WOLF CREEK
NUCLEAR OPERATING CORPORATION

Cynthia R. Hafenstine
Manager Regulatory Affairs

May 4, 2016

RA 16-0040

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Subject: Docket No. 50-482: Transmittal of 2015 Annual Financial Reports

Gentlemen:

Wolf Creek Nuclear Operating Corporation (WCNOC) is transmitting one copy each of the enclosed 2015 annual reports, including financial statements, for its owners: Kansas Gas and Electric Company (KGE), a wholly-owned subsidiary of Westar Energy, Inc., Kansas City Power & Light Company (KCPL), a wholly-owned subsidiary of Great Plains Energy Incorporated, and Kansas Electric Power Cooperative, Inc. (KEPCo). This information is being submitted in accordance with 10 CFR 50.71(b).

This letter contains no commitments. If you have any questions concerning this matter, please contact me at (620) 364-4204.

Sincerely,

Cynthia R. Hafenstine

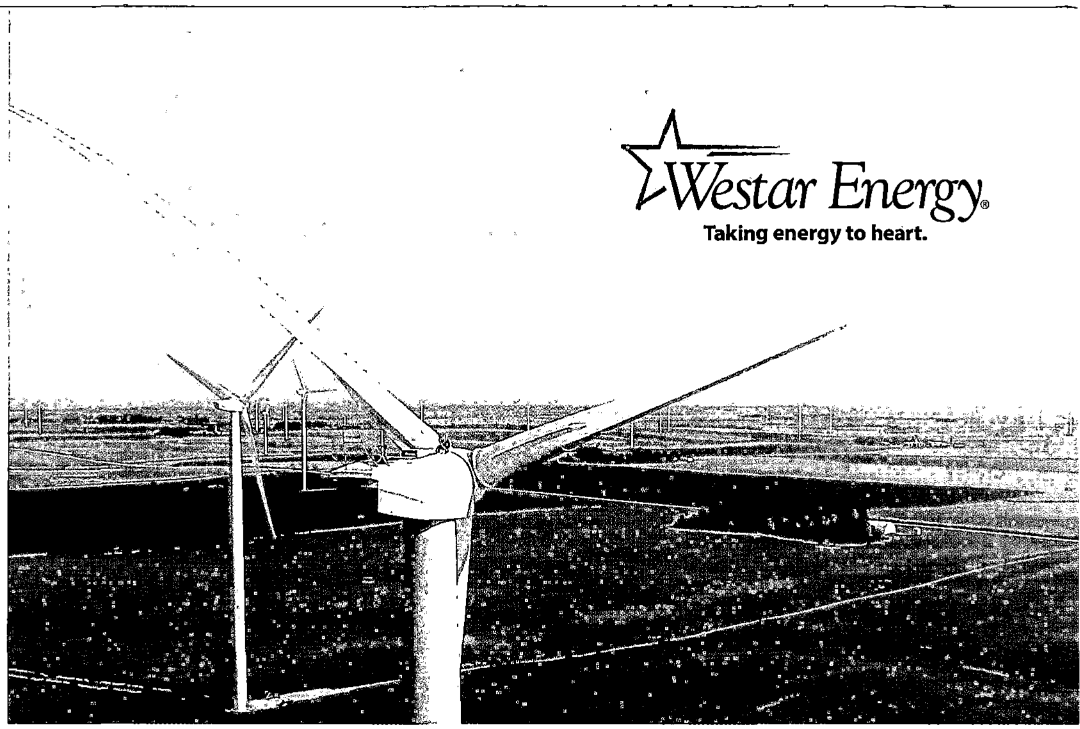
Cynthia R. Hafenstine

CRH/rlt

Enclosure: I Westar Energy 2015 Annual Report
II Great Plains Energy 2015 Annual Report
III Kansas Electric Power Cooperative, Inc. 2015 Annual Report

cc: M. L. Dapas (NRC), w/e
C. F. Lyon (NRC), w/e
N. H. Taylor (NRC), w/e
Senior Resident Inspector (NRC), w/e

M004
NRR



Westar Energy
Taking energy to heart.

2015 Annual Report

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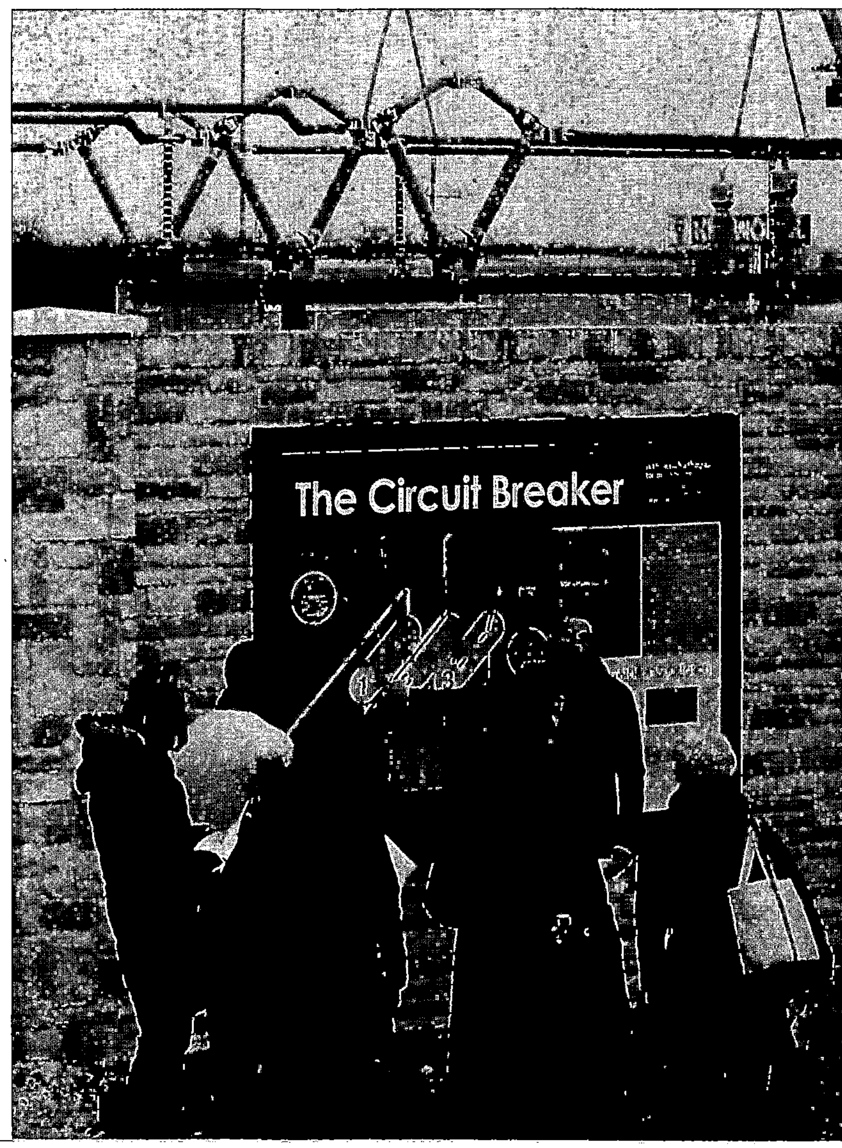


Dear Shareholders,

Election years always take me back to the civics lessons of my youth—the power of democracy, the right to vote and a reminder that with privilege comes responsibility. At Westar Energy, we are privileged to serve our customers with clean, safe, reliable and affordable energy that makes modern life possible. With that comes great responsibility.

That responsibility extends beyond keeping the lights on, though. At Westar, corporate responsibility means taking to heart the interests of our investors, customers, employees and the communities we serve. We keep those interests at the forefront of our decision-making by tracking our progress in five areas: financial performance, customer and community satisfaction, operational effectiveness, navigating regulatory changes and building an engaging culture in which we can attract, retain and develop talent for the future.

I'm pleased to share with you how we did in 2015 across those five areas and to share our plans to keep moving forward.

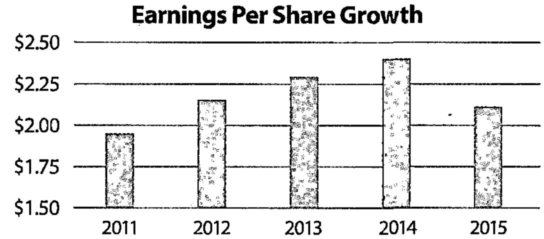
Financial Performance

I'm happy to report that **Westar was a bright spot among utilities**, even as the market wasn't very kind to utilities last year. Our **total shareholder return—from share price appreciation plus the dividends we paid—was 7 percent** versus negative 1 percent on average for our peers with which we compare. In fact, **we outperformed 14 of our 15 peers.** We again **increased your dividend—for the 11th consecutive year**.

Though our market performance was good, **earnings were disappointing.** Mostly this resulted from the effects of mild weather, softer sales to a few of our large customers most affected by low oil prices and global industrial demand, and lower allowed returns on investment. We were able to offset some—but not all—of those effects by aggressively managing our expenses and refinancing to take advantage of lower interest rates.

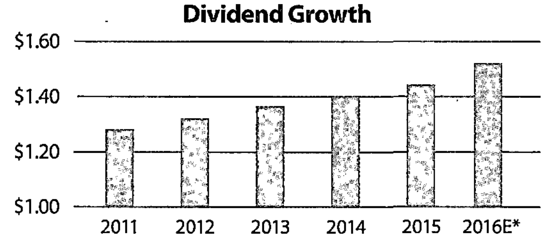
Westar stock continued to provide growth and income opportunities for you last year.

Earnings Per Share Growth



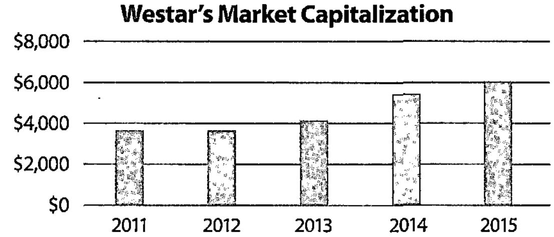
EPS from continuing operations

Dividend Growth

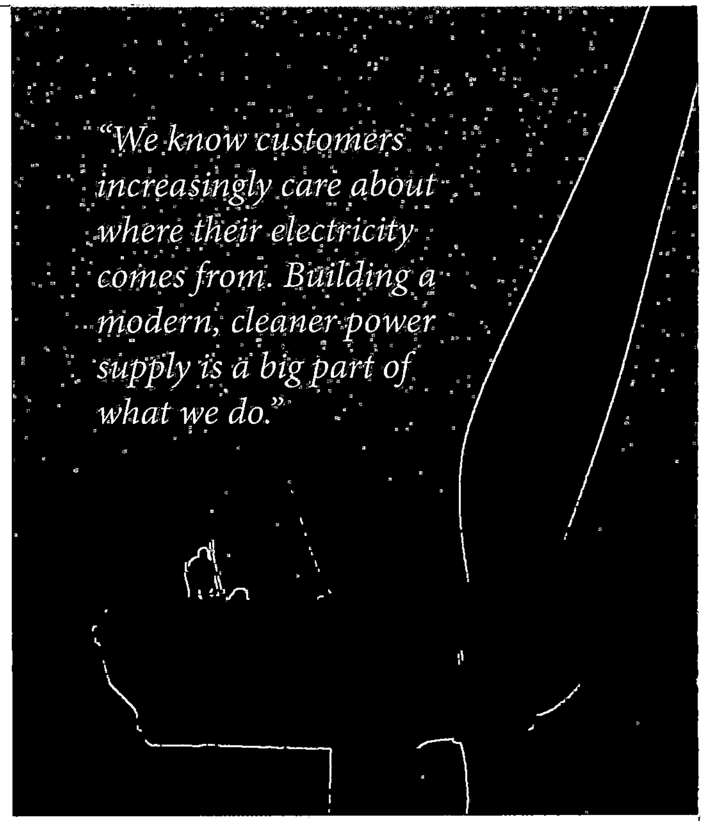


**Estimated*

Westar's Market Capitalization



Dollars in Millions



We've put plans together that we expect will continue that trend. I'm pleased to announce that our board of directors recently expressed confidence in our business by approving an even **larger step-up in our dividend this year.**

Earlier this year our stock price reached an all-time high. At year end, our **market capitalization—the value of all Westar shares outstanding—was about $6 billion, double what it was in 2009.**

Our senior secured credit ratings held steady at strong investment grade: A2/A.

Customer and Community Satisfaction

Creating an exceptional customer experience for those we serve continues to be at the heart of what we do. We met our customer satisfaction goals in 2015 and will continue to raise the bar this year.

We know customers increasingly care about where their electricity comes from. Building a modern, cleaner power supply is a big part of what we do. Late in the year we announced our plans to expand our green energy. With the addition of our newest wind turbines, which will start producing power late this year, we'll produce carbon-free electricity (renewables and nuclear) equal to more than half the electricity needs of every home, business, farm and ranch we serve by 2017.

Some of our customers want to increase their green energy even further. Westar Wind is an easy, affordable way of supporting renewable energy. Those who choose to participate can designate as much as 100 percent of their energy to be supplied through wind for a small additional cost.

Last year we installed 18 solar arrays for Kansas schools and charitable organizations. In 2016, we're launching a **community solar pilot** to give our customers the opportunity to access solar energy whether or not they have the option to install their own solar panels. This lets everyone have the option of getting some of their power from the sun.

We introduced additional services to **make our customers' lives a little easier.** We're offering several new options to help customers protect their households from unexpected, costly repairs without the hassle and frustration of trying to find a qualified technician.

Customers continue to be more engaged in their communities and are eager to learn more about how our employees and our company give back. So we began telling our story through our ***Imagine Kansas* video series**, and we were proud to receive positive feedback. One of the films was included in the Lawrence Free State Film Festival.

These were truly beautiful videos and—with everything produced in Kansas by Kansans—they serve as a subtle reminder of all we do to take care of our customers, our communities and to move Kansas forward. If you haven't seen them, I encourage you to visit **ImagineKansas.com.**

We don't do what we do for accolades, but it's gratifying to see others recognize our people for their progress. Not least of all, we earned the **Corporate Diversity Award from the Kansas Urban League** to recognize our building a more diverse culture. We also were honored to receive the **Edison Electric Institute Advocacy Excellence Award for our Education Station partnership with Topeka Public Schools.** Education Station features a substation and other educational resources helping educators teach and students learn more about the fields of science, technology, engineering and math by observing some of our actual network technology in operation.

We're proud of our commitment to the communities we serve. To help you learn more about how we give back, we've added a **corporate responsibility report, Moving Kansas Forward, to the back of this year's annual report.** This brief summary will give you a glimpse at our 2015 activities regarding **Environmental Leadership, People, Strong Communities, Safety and Investment.**

Operational Effectiveness

At the heart of what we do remains making, transmitting, distributing and selling the electricity that powers our customers' lives—enabling their comfort, convenience, learning, entertainment and productivity. So doing that well—and, importantly, safely—is critical.

We **kept our focus on safety**, ranking in the top quartile of comparable companies, doing so while being more productive by **reducing power plant outages and retiring older power generators**. We met our goal of **improving the performance of Wolf Creek, our state's only nuclear plant—and an important source of emission-free electricity**. We saw a slight increase in our customer outages, due in part to the always unpredictable Kansas storms, but **reduced the time it took to restore power after an outage.**

Technology is no longer an aid to what we do; it is so integral that in many respects it has become the work itself. An example is our new meter technology. By the end of 2015, we had **deployed this technology to more than a third of our customers, allowing them to get almost instantaneous information about how they use electricity, and reducing our costs to serve that electricity—not to mention reducing our emissions and fossil fuels, since we have fewer trucks on the road for service calls that can now be handled with technology**.

In 2016, we're launching pilot programs to improve the strength and resiliency of the power grid. These pilots include testing out **new technology to send us data about power line problems,** which will help us locate and fix downed power lines more quickly.

Navigating Regulatory Changes

Clean, safe, reliable—and affordable. These are the things we constantly strive for, and they involve trade-offs. The first three come at a cost. Fortunately, we've been able to manage the wave of regulatory mandates yet still keep electricity affordable in Kansas, keeping the prices our customers pay below the national average. In terms of clean, we met our goal, **producing 6.1 million emission-free, renewable megawatt hours, enough to power more than**

500,000 Kansas homes. And as I wrote earlier, we'll expand our green energy again this year.

Petitioning our regulators to reflect higher costs in our prices is never enjoyable, but we successfully navigated a general rate case last year, settling for about half of what we requested and aggressively managing expenses in response.

We continue to monitor and manage disruptive forces that could affect our business. Adapting to these changes is key. **Adaptability drives innovation.** Innovation—and the talent behind it—is the only thing that will sustain our continued success. Our employees continue to produce innovative ideas, like using **unmanned aerial vehicles** equipped with cameras to complete routine maintenance checks of our equipment in remote locations. This program will improve both safety and efficiency.

In 2016, we'll participate in a proceeding before our state regulators to address **cost structures for customers who generate some of their own power while continuing to rely on the benefits of being connected to the power network.** While we don't have a lot of those customers in Kansas yet, proactively addressing the issue helps keep energy affordable for all our customers while giving them more choice. Having a game plan for how we move forward will also help promote the continued development of solar as part of a diverse energy mix for Kansas.

Sustainable Talent, Engaging Culture

Every business is a people business. People are the difference between success and failure in everything we do. Our success—more than a century of it—has been the direct result of our employees and their passion for serving our customers. Many of them are baby boomers and more of them are retiring each year. We work hard to find, recruit and hire the kind of people who will carry on our mission—for every community we have the privilege of serving.

Recruiting young people right out of college or technical school is a big part of how we are filling the gap. We **earned top honors for "quality of life" and "providing the best intern experience in the energy industry" in recent internship rankings.** We also launched PowerGEN, a group for our young professionals, as we mentor our next generation of Westar leaders.

Summary

I have had the privilege—and responsibility—of being Westar's CEO now for more than four years. I'm proud to be associated with people who take our customers, investors, co-workers and communities to heart. Thank you for your confidence and your continuing investment in our company. In 2016, we'll continue working hard to power lives—one home, one business, one community at a time—with safe, clean, reliable electricity and the highest dedication to those we serve.

With Warmest Regards,

Mark A. Ruelle
President and Chief Executive Officer

DIRECTORS

CHARLES Q. CHANDLER IV (62)
Chairman of the Board
Director since 1999
Chairman since 2002
Chairman of the Board and Chief Executive Officer
INTRUST Bank, N.A.
Wichita, Kansas
Committees: Nominating, Corporate Governance

MOLLIE HALE CARTER (53)
Director since 2003
Chairman of the Board, President and Chief Executive Officer
Sunflower Financial, Inc.
Salina, Kansas
Committees: Compensation, Finance

R.A. EDWARDS III (70)
Director since 2001
Chairman of the Board
First National Bank of Hutchinson
Hutchinson, Kansas
Committees: Audit, Nominating, Corporate Governance

JERRY B. FARLEY (69)
Director since 2004
President
Washburn University
Topeka, Kansas
Committees: Audit, Nominating, Corporate Governance

RICHARD L. HAWLEY (66)
Director since 2011
Executive Vice President and Chief Financial Officer (Retired)
Nicor, Inc.
Bellevue, Washington
Committees: Audit, Compensation

B. ANTHONY ISAAC (63)
Director since 2003
Senior Vice President and Head Select Service Strategy and Development
Hyatt Hotels Corporation
Wichita, Kansas
Committees: Compensation, Finance

SANDRA A.J. LAWRENCE (58)
Director since 2004
Executive Vice President and Chief Financial Officer
Children's Mercy Hospital
Kansas City, Missouri
Committees: Compensation, Nominating, Corporate Governance

MARK A. RUELLE (54)
Director since 2011
President and Chief Executive Officer
Westar Energy, Inc.
Topeka, Kansas

S. CARL SODERSTROM, JR. (62)
Director since 2010
Senior Vice President and Chief Financial Officer (Retired)
ArvinMeritor
Longwood, Florida
Committees: Audit, Finance

OFFICERS

MARK A. RUELLE (54)
23 years of service
Director, President and Chief Executive Officer

ANTHONY D. SOMMA (52)
21 years of service
Senior Vice President, Chief Financial Officer and Treasurer

GREGORY A. GREENWOOD (50)
22 years of service
Senior Vice President, Strategy

BRUCE A. AKIN (51)
28 years of service
Senior Vice President, Power Delivery

JERL L. BANNING (55)
7 years of service
Senior Vice President, Operations Support and Administration

JEFFREY L. BEASLEY (58)
38 years of service
Vice President, Customer Care

JOHN T. BRIDSON (46)
22 years of service
Senior Vice President, Generation and Marketing

MICHEL' PHILIPP COLE (53)
12 years of service
Vice President, Corporate Communications and Public Affairs

DEBRA A. GRUNST (50)
5 years of service
Vice President, Information Technology

KELLY B. HARRISON (57)
34 years of service
Vice President, Transmission

LARRY D. IRICK (59)
16 years of service
Vice President, General Counsel and Corporate Secretary

KEVIN L. KONGS (54)
26 years of service
Vice President, Controller

JEFFREY L. MARTIN (45)
22 years of service
Vice President, Regulatory Affairs

Ages and years of service are as of March 31, 2016.

2015 FINANCIAL MEASURES

	2015	2014
FINANCIAL DATA *(Dollars in Millions)*		
INCOME HIGHLIGHTS		
Revenues	**$2,459**	$2,602
Net income	**301**	322
Net income attributable to Westar Energy, Inc.	**292**	313
BALANCE SHEET HIGHLIGHTS		
Total assets	**$10,706**	$10,289
Common stock equity	**3,657**	3,295
Capital structure:		
Common equity	**52%**	49%
Noncontrolling interests	**<1%**	<1%
Long-term debt, including VIEs	**48%**	51%
OPERATING DATA		
Sales (Thousands of MWh)		
Retail	**19,450**	19,788
Wholesale	**8,492**	9,544
Customers	**700,000**	698,000
COMMON STOCK DATA		
PER SHARE HIGHLIGHTS		
Basic earnings per common share	**$2.11**	$2.40
Dividends declared per common share	**$1.44**	$1.40
Book value per share	**$25.87**	$25.02
STOCK PRICE PERFORMANCE		
Common stock price range:		
High	**$44.03**	$43.15
Low	**$33.88**	$31.67
Stock price at year end	**$42.41**	$41.24
Average equivalent common shares outstanding (in thousands)	**137,958**	130,015
Dividend yield (based on year end annualized dividend)	**3.4%**	3.4%

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2015

OR

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

For the transition period from __________ to __________

Commission File Number 1-3523

WESTAR ENERGY, INC.

(Exact name of registrant as specified in its charter)

Kansas	**48-0290150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

818 South Kansas Avenue, Topeka, Kansas 66612 **(785) 575-6300**

(Address, including Zip code and telephone number, including area code, of registrant's principal executive offices)

Securities registered pursuant to section 12(b) of the Act:

Common Stock, par value $5.00 per share	**New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

Securities registered pursuant to section 12(g) of the Act: **None**

Indicate by check mark whether the registrant is a well-known seasoned issuer (as defined in Rule 405 of the Act). Yes [X] No [ ]

Indicate by check mark whether the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the 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 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 (as defined in Rule 12b-2 of the Act). Check one:

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $4,831,132,308 at June 30, 2015.

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

Common Stock, par value $5.00 per share	**141,622,586 shares**
(Class)	(Outstanding at February 17, 2016)

DOCUMENTS INCORPORATED BY REFERENCE:

Description of the document	Part of the Form 10-K
Portions of the Westar Energy, Inc. definitive proxy statement to be used in connection with the registrant's 2016 Annual Meeting of Shareholders	Part III (Item 10 through Item 14) (Portions of Item 10 are not incorporated by reference and are provided herein)

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GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found throughout this report.

Abbreviation or Acronym	Definition
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
BNSF	BNSF Railway Company
Btu	British thermal units
CAA	Clean Air Act
CCB	Coal combustion byproducts
CO	Carbon monoxide
CO_2	Carbon dioxide
COLI	Corporate-owned life insurance
CPP	Clean Power Plan
CWA	Clean Water Act
CWIP	Construction work in progress
DOE	Department of Energy
DSPP	Direct Stock Purchase Plan
ECRR	Environmental Cost Recovery Rider
EPA	Environmental Protection Agency
EPS	Earnings per share
Exchange Act	Securities Exchange Act of 1934
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gas
IM	Integrated Marketplace
JEC	Jeffrey Energy Center
KCC	Kansas Corporation Commission
KCPL	Kansas City Power & Light Company
KDHE	Kansas Department of Health and Environment
KGE	Kansas Gas and Electric Company

Abbreviation or Acronym	Definition
La Cygne	La Cygne Generating Station
LTISA Plan	Long-term incentive and share award plan
MATS	Mercury and Air Toxics Standards
MMBtu	Millions of British thermal units
Moody's	Moody's Investors Service
MW	Megawatt(s)
MWh	Megawatt hour(s)
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NOx	Nitrogen oxides
NRC	Nuclear Regulatory Commission
PCB	Polychlorinated biphenyl
PM	Particulate matter
PPB	Parts per billion
PRB	Powder River Basin
Prairie Wind	Prairie Wind Transmission, LLC
ROE	Return on equity
RSU	Restricted share unit
RTO	Regional transmission organization
S&P	Standard & Poor's Ratings Services
S&P 500	Standard & Poor's 500 Index
S&P Electric Utilities	Standard & Poor's Electric Utility Index
SEC	Securities and Exchange Commission
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
SSCGP	Southern Star Central Gas Pipeline
TFR	Transmission formula rate
VaR	Value-at-Risk
VIE	Variable interest entity
Wolf Creek	Wolf Creek Generating Station

FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Annual Report on Form 10-K are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we "believe," "anticipate," "target," "expect," "estimate," "intend" and words of similar meaning. Forward-looking statements describe our future plans, objectives, expectations or goals. Such statements address future events and conditions concerning matters such as, but not limited to:

- amount, type and timing of capital expenditures,
- earnings,
- cash flow,
- liquidity and capital resources,
- litigation,
- accounting matters,
- possible corporate restructurings, acquisitions and dispositions,
- compliance with debt and other restrictive covenants,
- interest rates and dividends,
- environmental matters,
- regulatory matters,
- nuclear operations, and
- the overall economy of our service area and its impact on our customers' demand for electricity and their ability to pay for service.

What happens in each case could vary materially from what we expect because of such things as:

- risks related to operating in a heavily regulated industry that is subject to unpredictable political, legislative, judicial and regulatory developments, which can impact our operations, results of operations, and financial condition,
- the difficulty of predicting the magnitude and timing of changes in demand for electricity, including with respect to emerging competing services and technologies and conservation and energy efficiency measures,
- the impact of weather conditions, including as it relates to sales of electricity and prices of energy commodities,
- equipment damage from storms and extreme weather,
- economic and capital market conditions, including the impact of inflation or deflation, changes in interest rates, the cost and availability of capital and the market for trading wholesale energy,
- the impact of changes in market conditions on employee benefit liability calculations and funding obligations, as well as actual and assumed investment returns on invested plan assets,
- the impact of changes in estimates regarding our Wolf Creek Generating Station (Wolf Creek) decommissioning obligation,
- the existence or introduction of competition into markets in which we operate,
- the impact of changing laws and regulations relating to air and greenhouse gas (GHG) emissions, water emissions, waste management and other environmental matters,
- risks associated with execution of our planned capital expenditure program, including timing and receipt of regulatory approvals necessary for planned construction and expansion projects as well as the ability to complete planned construction projects within the terms and time frames anticipated,
- cost, availability and timely provision of equipment, supplies, labor and fuel we need to operate our business,
- availability of generating capacity and the performance of our generating plants,
- changes in regulation of nuclear generating facilities and nuclear materials and fuel, including possible shutdown or required modification of nuclear generating facilities,
- additional regulation due to Nuclear Regulatory Commission (NRC) oversight to ensure the safe operation of Wolf Creek, either related to Wolf Creek's performance, or potentially relating to events or performance at a nuclear plant anywhere in the world,
- uncertainty regarding the establishment of interim or permanent sites for spent nuclear fuel storage and disposal,
- homeland and information and operating systems security considerations,
- changes in accounting requirements and other accounting matters,
- changes in the energy markets in which we participate resulting from the development and implementation of real time and next day trading markets, and the effect of the retroactive repricing of transactions in such markets following execution because of changes or adjustments in market pricing mechanisms by regional transmission organizations (RTOs) and independent system operators,
- reduced demand for coal-based energy because of actual or potential climate impacts and the development of alternate energy sources,
- current and future litigation, regulatory investigations, proceedings or inquiries,
- cost of fuel used in generation and wholesale electricity prices, and
- other factors discussed elsewhere in this report, including in "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and in other reports we file from time to time with the Securities and Exchange Commission (SEC).

These lists are not all-inclusive because it is not possible to predict all factors. This report should be read in its entirety. No one section of this report deals with all aspects of the subject matter. The reader should not place undue reliance on any forward-looking statement, as forward-looking statements speak only as of the date such statements were made. We undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made.

PART I

ITEM 1. BUSINESS

GENERAL

Overview

We are the largest electric utility in Kansas. Unless the context otherwise indicates, all references in this Annual Report on Form 10-K to "the company," "we," "us," "our" and similar words are to Westar Energy, Inc. and its consolidated subsidiaries. The term "Westar Energy" refers to Westar Energy, Inc., a Kansas corporation incorporated in 1924, alone and not together with its consolidated subsidiaries.

We provide electric generation, transmission and distribution services to approximately 700,000 customers in Kansas. Westar Energy provides these services in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric Company (KGE), Westar Energy's wholly-owned subsidiary, provides these services in south-central and southeastern Kansas, including the city of Wichita. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

Strategy

We expect to continue operating as a vertically integrated, regulated, electric utility. Significant elements of our strategy include maintaining a flexible, clean and diverse energy supply portfolio. In doing so, we continue to expand renewable generation, build and upgrade our electrical infrastructure and develop systems and programs with regard to how our customers use energy and interact with us.

OPERATIONS

General

As noted above, we supply electric energy at retail to customers in Kansas. We also supply electric energy at wholesale to municipalities and electric cooperatives in Kansas, and have contracts for the sale or purchase of wholesale electricity with other utilities.

Following is the percentage of our revenues by customer classification. Classification of customers as residential, commercial and industrial requires judgment and our classifications may be different from other companies. Assignment of tariffs is not dependent on classification.

Year Ended December 31,	2015	2014	2013
Residential	31%	31%	31%
Commercial	29%	28%	28%
Industrial	16%	16%	16%
Wholesale	13%	15%	15%
Transmission	10%	9%	9%
Other	1%	1%	1%
Total	100%	100%	100%

The percentage of our retail electricity sales by customer class was as follows.

Year Ended December 31,	2015	2014	2013
Residential	33%	34%	34%
Commercial	39%	38%	38%
Industrial	28%	28%	28%
Total	100%	100%	100%

Generating Capability and Firm Capacity Purchases

We have 6,267 megawatts (MW) of generating capability in service. See "Item 2. Properties" for additional information about our generating units. Further, we purchase electricity pursuant to long-term contracts from renewable generation facilities with an installed design capacity of 920 MW. Our generating capability and net generation by source are summarized below.

Source	Capability (MW)	Percent of Total Capability	Net Generation (MWh)	Percent of Total Net Generation
Coal	3,213	44%	17,352,379	71%
Nuclear	551	8%	4,056,184	16%
Natural gas/diesel	2,354	33%	1,301,884	5%
Renewable	1,069	15%	2,061,255	8%
Total	7,187	100%	24,771,702	100%

We have entered into four additional wind energy agreements. One agreement is for approximately 200 MW of additional installed designed capability. In addition, we have begun constructing a wind generating facility expected to have a designed installed capability of approximately 280 MW. The last two agreements are for approximately 100 MW each with Westar holding an option for the purchase of one of the facilities. These four agreements are to provide approximately 680 MW generating capability by early 2017.

Our aggregate 2015 peak system net load of 5,167 MW occurred in July 2015. Because of the intermittent nature of wind generation, only 152 MW of net accredited generating capacity is associated with our wind generation facilities. Our net accredited generating capacity, combined with firm capacity purchases and sales and potentially interruptible load, provided a capacity margin of 20% above system peak responsibility at the time of our 2015 peak system net load, which satisfied Southwest Power Pool, Inc. (SPP) planning requirements.

Under wholesale agreements, we provide firm generating capacity to other entities as set forth below.

Utility[(a)]	Capacity (MW)	Expiration
Midwest Energy, Inc.	120	May 2017
Midwest Energy, Inc.	35	May 2017
Mid-Kansas Electric Company, LLC	172	January 2019
Kansas Power Pool	59	December 2022
Midwest Energy, Inc.	150	May 2025
Total	536	

[(a)] *Under a wholesale agreement that expires in May 2039, we provide base load capacity to the city of McPherson, Kansas, and in return the city provides peaking capacity to us. During 2015, we provided approximately 89 MW to, and received approximately 148 MW from, the city. The amount of base load capacity provided to the city is based on a fixed percentage of its annual peak system load. The city is a full requirements customer of Westar Energy. The agreement for the city to provide capacity to us is treated as a capital lease.*

Fossil Fuel Generation

The effectiveness of a fuel to produce heat is measured in British thermal units (Btu). The higher the Btu content of a fuel, the smaller the volume of fuel that is required to produce a given amount of electricity. We measure the quantity of heat consumed during the generation of electricity in millions of British thermal units (MMBtu).

Coal

Jeffrey Energy Center (JEC): The three coal-fired units at JEC have an aggregate capacity of 2,146 MW, of which we own or consolidate through a variable interest entity (VIE) a combined 92% share, or 1,975 MW. We have a long-term coal supply contract with Alpha Natural Resources, Inc. to supply coal to JEC from surface mines located in the Powder River Basin (PRB) in Wyoming. The contract contains a schedule of minimum annual MMBtu quantities. All of the coal used at JEC is purchased under this contract, which expires December 31, 2020. The contract provides for price escalation based on certain costs of production. The price for quantities purchased in excess of the scheduled annual minimum is subject to renegotiation every five years to provide an adjusted price for the ensuing five years that reflects the market prices at the time of renegotiation. The most recent price adjustment was effective January 1, 2013.

The BNSF Railway Company (BNSF) and Union Pacific Railroad Company transport coal to JEC under a long-term rail transportation contract. The contract term continues through December 31, 2020, at which time we plan to enter into a new contract. The contract price is subject to price escalation based on certain costs incurred by the railroads.

The average delivered cost of coal consumed at JEC during 2015 was approximately $1.74 per MMBtu, or $29.01 per ton.

La Cygne Generating Station (La Cygne): The two coal-fired units at La Cygne have an aggregate generating capacity of 1,398 MW. Our share of the units is 50%, or 699 MW, of which we either own directly or consolidate through a VIE. La Cygne uses primarily PRB coal but one of the two units also uses a small portion of locally-mined coal. The operator of La Cygne, Kansas City Power & Light Company (KCPL), arranges coal purchases and transportation services for La Cygne. Approximately 95%, 90% and 35% of La Cygne's PRB coal requirements are under contract for 2016, 2017 and 2018, respectively. About 90%, 85% and 100% of those commitments under contract are fixed price for 2016, 2017 and 2018, respectively. As the PRB coal contracts expire, we anticipate that KCPL will negotiate new supply contracts or purchase coal on the spot market.

All of the La Cygne PRB coal is transported under KCPL's rail transportation agreements with BNSF through 2018 and Kansas City Southern Railroad through 2020. During 2015, our share of average delivered cost of coal consumed at La Cygne was approximately $1.88 per MMBtu, or $32.64 per ton.

Lawrence and Tecumseh Energy Centers: Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 539 MW. We purchase PRB coal for these energy centers under a contract with Arch Coal, Inc. that provides for 100% of the coal requirements for these facilities through 2017. BNSF transports coal for these energy centers under a contract that expires in December 2020.

During 2015, the average delivered cost of coal consumed in the Lawrence units was approximately $1.75 per MMBtu, or $31.30 per ton. The average delivered cost of coal consumed in the Tecumseh units was approximately $1.76 per MMBtu, or $31.46 per ton.

Natural Gas

We use natural gas as a primary fuel at our Gordon Evans, Murray Gill, Hutchinson, Spring Creek and Emporia Energy Centers and at the State Line facility. We can also use natural gas as a supplemental fuel in the coal-fired units at Lawrence and Tecumseh Energy Centers. During 2015, we consumed 13.4 million MMBtu of natural gas for a total cost of $48.9 million, or approximately $3.64 per MMBtu. Natural gas accounted for approximately 5% of the total MMBtu of fuel we consumed and approximately 11% of our total fuel expense in 2015. From time to time, we may enter into contracts, including the use of derivatives, in an effort to manage the cost of natural gas. For additional information about our exposure to commodity price risks, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

We maintain a natural gas transportation arrangement for Hutchinson Energy Center with Kansas Gas Service. The agreement has historically expired on April 30 of each year and is renegotiated for an additional one year term. We meet a portion of our natural gas transportation requirements for Gordon Evans, Murray Gill, Lawrence, Tecumseh and Emporia Energy Centers through firm natural gas transportation capacity agreements with Southern Star Central Gas Pipeline (SSCGP). We meet all of the natural gas transportation requirements for the State Line facility through a firm transportation agreement with SSCGP. The firm transportation agreement that serves Gordon Evans and Murray Gill Energy Centers expires in April 2020, and the agreement for Lawrence and Tecumseh Energy Centers expires in April 2030. The agreement for the State Line facility extends through October 2022, while the agreement for Emporia Energy Center is in place until December 2028, and is renewable for five-year terms thereafter. We meet all of the natural gas transportation requirements for Spring Creek Energy Center through an interruptible month-to-month transportation agreement with ONEOK Gas Transportation, LLC.

Diesel

We use diesel to start some of our coal generating stations, as a primary fuel in the Hutchinson No. 4 combustion turbine and in our diesel generators. We purchase No. 2 diesel in the spot market. We maintain quantities in inventory that we believe will allow us to facilitate economic dispatch of power and satisfy emergency requirements. We do not use significant amounts of diesel in our operations.

Nuclear Generation

General

Wolf Creek is a 1,171 MW nuclear power plant located near Burlington, Kansas. KGE owns a 47% interest in Wolf Creek, or 551 MW. Wolf Creek's operating license, issued by the NRC, is effective until 2045. Wolf Creek Nuclear Operating Corporation, an operating company owned by each of the plant's owners in proportion to their ownership share of the plant, operates the plant. The plant's owners pay operating costs proportionate to their respective ownership share.

Fuel Supply

Wolf Creek has on hand or under contract all of the uranium and conversion services needed to operate through March 2018 and approximately 37% of the uranium and conversion services needed after that date through September 2022. The owners also have under contract all of the uranium enrichment and fabrication services required to operate Wolf Creek through March 2027 and September 2025, respectively. All such agreements have been entered into in the ordinary course of business.

Operations and Regulation

Plant performance, including extended or unscheduled shutdowns of Wolf Creek, could cause us to purchase replacement power, rely more heavily on our other generating units and/or reduce amounts of power available for us to sell in the wholesale market. Plant performance also affects the degree of regulatory oversight and related costs.

Wolf Creek normally operates on an 18-month planned refueling and maintenance outage schedule. As authorized by our regulators, incremental maintenance costs of planned refueling and maintenance outages are deferred and amortized ratably over the period between planned refueling and maintenance outages. In early 2015, Wolf Creek underwent a planned refueling and maintenance outage. Our share of the outage costs were approximately $31.9 million. The next refueling and maintenance outage is planned for the fall of 2016.

The NRC evaluates, monitors and rates various inspection findings and performance indicators for Wolf Creek based on safety significance. Although not expected, the NRC could impose an unscheduled plant shutdown due to security or safety concerns. Those concerns need not be related to Wolf Creek specifically, but could be due to concerns about nuclear power generally or circumstances at other nuclear plants in which we have no ownership.

See Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies," for additional information regarding our nuclear operations.

Wind Generation

Wind is our primary source of renewable energy. As of December 31, 2015, we owned approximately 149 MW of designed installed wind capability and had under contract the purchase of wind energy produced from approximately 1,314 MW of designed installed wind capability. Of the 1,314 MW under contract, 914 MW are currently in operation and approximately 400 MW are associated with agreements that are scheduled to deliver power beginning in early 2017. We have begun constructing a wind generating facility that is expected to have a designed installed capability of approximately 280 MW and is scheduled to begin delivering power in early 2017.

Other Fuel Matters

The table below provides our weighted average cost of fuel, including transportation costs.

	2015	2014	2013
Per MMBtu:			
Nuclear	$ 0.66	$ 0.66	$ 0.75
Coal	1.77	1.80	1.82
Natural gas	3.64	5.71	4.41
Diesel	15.55	21.31	22.89
All generating stations	1.74	1.90	1.91
Per MWh Generation:			
Nuclear	$ 6.72	$ 6.79	$ 7.86
Coal	19.78	20.04	20.26
Natural gas/diesel	37.16	62.84	46.38
All generating stations	18.44	20.27	20.45

Our wind production has no associated fuel costs and is, therefore, not included in the table above.

Purchased Power

In addition to generating electricity, we also purchase power. Factors that cause us to purchase power include contractual arrangements, planned and unscheduled outages at our generating plants, favorable wholesale energy prices compared to our costs of production, weather conditions and other factors. In 2015, purchased power comprised approximately 28% of our total fuel and purchased power expense. Our weighted average cost of purchased power per Megawatt hour (MWh) was $27.28 in 2015, $37.26 in 2014 and $33.63 in 2013.

Transmission

Regional Transmission Organization

The Federal Energy Regulatory Commission (FERC) requires owners of regulated transmission assets to allow third parties nondiscriminatory access to their transmission systems. We are a member of the SPP RTO and transferred the functional control of our transmission system, including the approval of transmission service, to the SPP. The SPP coordinates the operation of our transmission system within an interconnected transmission system that covers all or portions of 14 states. The SPP collects revenues for the use of each transmission owner's transmission system. Transmission customers transmit power purchased and generated for sale or bought for resale in the wholesale market throughout the entire SPP system. Transmission capacity is sold on a first come/first served non-discriminatory basis. All transmission customers are charged rates applicable to the transmission system in the zone where energy is delivered, including transmission customers that may sell power inside our certificated service territory. The SPP then distributes as revenue to transmission owners the amounts it collects from transmission users less an amount it retains to cover administrative expenses.

Southwest Power Pool Integrated Market

The SPP launched their new Integrated Marketplace (IM) in March 2014. The IM is similar to organized power markets currently operating in other RTOs. The IM impacts how we commit and sell the output from our generation facilities and buy power to meet the needs of our customers. The SPP has the authority to start and stop generating units participating in the market and selects the lowest cost resource mix to meet the needs of the various SPP customers while ensuring reliable operations of the transmission system.

Transmission Investments

We own a 50% interest in Prairie Wind Transmission, LLC (Prairie Wind), which is a joint venture between us and Electric Transmission America, LLC, which itself is a joint venture between affiliates of American Electric Power Company, Inc. and Berkshire Hathaway Energy Company. In 2014, Prairie Wind completed construction on, and energized, a 108 mile 345 kV double-circuit transmission line that is now being used to provide transmission service in the SPP.

In 2011, the FERC issued Order No. 1000, which revised the FERC's existing regulations governing the process for planning enhancements and expansions of the electric transmission grid, along with the corresponding process for allocating the costs of such expansions. Among other things, Order No. 1000 sets forth a framework pursuant to which certain transmission projects that are approved by the RTOs become subject to a competitive bidding process whereby qualified entities can build and own the transmission facilities, even if the entities are not located in the service territory covered by the transmission facilities. This process is complicated, and is governed by Order No. 1000 and the tariff each RTO has with the FERC. In addition, notwithstanding the competitive processes created by Order No. 1000, incumbent utilities maintain a right of first refusal for certain transmission projects, depending on, among other things, the date by which the projects must be completed, the size of the projects and whether the incumbent utilities have pre-existing facilities that are being impacted by the projects.

We are actively participating in transmission planning activities and implementation of Order No. 1000 in the SPP and the Midcontinent Independent System Operator, Inc. We believe we have opportunities to develop transmission infrastructure, including projects pursuant to which we, as the incumbent, have a right of first refusal and those projects that are subject to the Order No. 1000 competitive processes. However, due in part to the long-term nature of transmission planning activities, the uncertainty surrounding the implementation of the Clean Power Plan (CPP) and its impact on the region's generating fleet and the infancy of implementation of Order No. 1000, we are unable to predict the impact of Order No. 1000. Accordingly, in our forecasted capital expenditure table, there are no dollars of investment associated with Order No. 1000 projects.

Regulation and Our Prices

Kansas law gives the Kansas Corporation Commission (KCC) general regulatory authority over our retail prices, extensions and abandonments of service and facilities, the classification of accounts, the issuance of some securities and various other matters. We are also subject to the jurisdiction of FERC, which has authority over wholesale electricity sales, including prices, the transmission of electric power and the issuance of some securities. We are subject to the jurisdiction of the NRC for nuclear plant operations and safety. Regulatory authorities have established various methods permitting adjustments to our prices for the recovery of costs. For portions of our cost of service, regulators allow us to adjust our prices periodically through the application of a formula that tracks changes in our costs, which reduces the time between making expenditures or investments and reflecting them in the prices we charge customers. However, for the remaining portions of our cost of service, we must file a general rate review, which lengthens the period of time between when we make and recover expenditures and a return on our investments. See Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," for information regarding our rate proceedings with the KCC and FERC.

Environmental Matters

We are subject to various federal, state and local environmental laws and regulations. Environmental laws and regulations affecting our operations are overlapping, complex, subject to changes, have become more stringent over time and are expensive to implement. Such laws and regulations relate primarily to air quality, water quality, the use of water and the handling, disposal and clean-up of hazardous and non-hazardous substances and wastes, including coal combustion byproducts (CCBs). These laws and regulations oftentimes require a lengthy and complex process for obtaining licenses, permits and approvals from governmental agencies for new, existing or modified facilities. If we fail to comply with such laws, regulations and permits, or fail to obtain and maintain necessary permits, we could be fined or otherwise sanctioned by regulators, and such fines or the cost of sanctions may not be recoverable in our prices. We have incurred and will continue to incur significant capital and other expenditures to comply with environmental laws and regulations.

Historically, we were permitted to recover certain of the costs associated with environmental projects through an environmental cost recovery rider, which, in general, allowed us to annually file with the KCC to adjust our prices for qualifying environmental improvements. In connection with the 2015 state general rate review, we agreed to no longer make annual filings with the KCC to adjust our prices to include costs associated with investments in air quality control equipment made during the prior year. The existing balance of costs associated with these investments were rolled into base prices. In the future, we will need to seek approval from the KCC for individual projects.

See "Item 1A. Risk Factors" and Notes 3 and 13 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation — KCC Proceedings — Environmental Costs" and "Commitments and Contingencies — Environmental Matters," respectively, for more information regarding environmental trends, risks and laws and regulations.

Renewable Energy Standard

In May 2015, Kansas repealed a state mandate to maintain a minimum amount of renewable energy sources, effective January 1, 2016.

Safety and Health Regulation

The safety and health of our employees is vital to our business. We are subject to a number of federal and state laws and regulations, including the Occupational Safety and Health Act of 1970. We have measures in place to promote the safety and health of our employees and to monitor our compliance with such laws and regulations.

Information Technology

We rely upon information technology networks and systems to process, transmit and store electronic information, and to manage or support a variety of business processes and activities, including the generation, transmission and distribution of electricity, supply chain functions and the invoicing and collection of payments from our customers. These networks and systems are in some cases owned or managed by third-party service providers. Cybersecurity breaches, criminal activity, terrorist attacks and other disruptions to our information technology infrastructure, including infrastructure owned by third-parties we utilize, could interfere with our operations, could expose us or our customers or employees to a risk of loss and could expose us to liability or regulatory penalties or cause us reputational damage or other harm to our business. We have taken measures to secure our network and systems, but such measures may not be sufficient, especially due to the increasing sophistication of cyberattacks. See "Item 1A. Risk Factors" for additional information.

SEASONALITY

Our electricity sales and revenues are seasonal, with the third quarter typically accounting for the greatest of each. Our electricity sales are impacted by weather conditions, the economy of our service territory and other factors affecting customers' demand for electricity.

EMPLOYEES

As of February 17, 2016, we had 2,330 employees, 1,235 of which were covered by a contract with Locals 304 and 1523 of the International Brotherhood of Electrical Workers that extends through June 30, 2017.

ACCESS TO COMPANY INFORMATION

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K are available free of charge either on our Internet website at www.westarenergy.com or through requests addressed to our investor relations department. These reports are available as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. The information contained on our Internet website is not part of this document.

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During the Past Five Years
Mark A. Ruelle	54	Director, President and Chief Executive Officer (since August 2011)	**Westar Energy, Inc.** Director, President and Chief Financial Officer (May 2011 to July 2011) Executive Vice President and Chief Financial Officer (January 2003 to April 2011)
Bruce A. Akin	51	Senior Vice President, Power Delivery (since January 2015)	**Westar Energy, Inc.** Vice President, Power Delivery (February 2012 to December 2014) Vice President, Operations Strategy and Support (July 2007 to February 2012)
Jerl L. Banning	55	Senior Vice President, Operations Support and Administration (since January 2015)	**Westar Energy, Inc.** Vice President, Human Resources and IT (January 2014 to December 2014) Vice President, Human Resources (February 2010 to December 2013)
John T. Bridson	46	Senior Vice President, Generation and Marketing (since January 2015)	**Westar Energy, Inc.** Vice President, Generation (February 2011 to December 2014) Executive Director, Generation (May 2010 to February 2011)
Gregory A. Greenwood	50	Senior Vice President, Strategy (since August 2011)	**Westar Energy, Inc.** Vice President, Major Construction Projects (December 2009 to July 2011)
Anthony D. Somma	52	Senior Vice President, Chief Financial Officer and Treasurer (since August 2011)	**Westar Energy, Inc.** Vice President, Treasurer (February 2009 to July 2011)
Larry D. Irick	59	Vice President, General Counsel and Corporate Secretary (since February 2003)	
Kevin L. Kongs	53	Vice President, Controller (since November 2013)	**Westar Energy, Inc.** Assistant Controller (October 2006 to November 2013)

Executive officers serve at the pleasure of the board of directors. There are no family relationships among any of the executive officers, nor any arrangements or understandings between any executive officer and other persons pursuant to which he was appointed as an executive officer.

ITEM 1A. RISK FACTORS

We operate in market and regulatory environments that involve significant risks, many of which are beyond our control. In addition to other information in this Form 10-K, including "Item 1. Business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and in other documents we file with the SEC from time to time, the following factors may affect our results of operations, our cash flows and the value of our equity and debt securities. These factors may cause results to differ materially from those expressed in any forward-looking statements made by us or on our behalf. The factors listed below are not intended to be an exhaustive discussion of all such risks, and the statements below must be read together with factors discussed elsewhere in this document and in our other filings with the SEC.

Weather conditions, including mild and severe weather, may adversely impact our consolidated financial results.

Weather conditions directly influence the demand for electricity. Our customers use electricity for heating in winter months and cooling in summer months. Because of air conditioning demand, typically we produce our highest revenues in the third quarter. Milder temperatures reduce demand for electricity and have a corresponding impact on our revenues. Unusually mild weather in the future could adversely affect our consolidated financial results.

In addition, severe weather conditions can produce storms that can inflict extensive damage to our equipment and facilities, which can require us to incur additional operating and maintenance expense and additional capital expenditures. Our prices may not always be adjusted timely or adequately to reflect these higher costs. Additionally, because many of our power plants use water for cooling, persistent or severe drought conditions could result in limited power production. High water conditions can also impair planned deliveries of fuel to our plants.

Our prices are subject to regulatory review and may not prove adequate to recover our costs and provide a fair return.

We must obtain from state and federal regulators the authority to establish terms and prices for our services. The KCC and, for most of our wholesale customers, FERC, use a cost-of-service approach that takes into account operating expenses, fixed obligations and recovery of and return on capital investments. Using this approach, the KCC and FERC set prices at levels calculated to recover such costs and a permitted return on investment. Except for wholesale transactions for which the price is not so regulated, and except to the extent the KCC and FERC permit us to modify our prices through the application of a formula that tracks changes in certain of our costs, our prices generally remain fixed until changed following a rate review. Further, the adjustments may be modified, limited or eliminated by regulatory or legislative actions. We may apply to change our prices or intervening parties may request that our prices be reviewed for possible adjustment.

Rate proceedings through which our prices and terms of service are determined typically involve numerous parties including electricity consumers, consumer advocates and governmental entities, some of whom take positions adverse to us. In addition, regulators' decisions may be appealed to the courts by us or other parties to the proceedings. These factors may lead to uncertainty and delays in obtaining or implementing changes to our prices or terms of service. There can be no assurance that our regulators will find all of our costs to have been prudently incurred. A finding that costs have been imprudently incurred can lead to disallowance of recovery for those costs. Further, the prices approved by the applicable regulatory body may not be sufficient for us to recover our costs and to provide for an adequate return on and of capital investments.

We cannot predict the outcome of any rate review or the actions of our regulators. The outcome of rate proceedings, or delays in implementing price changes to reflect changes in our costs, could have a material effect on our consolidated financial results.

Our costs of compliance with environmental laws and regulations, including those relating to GHG emissions, are significant, and the future costs of compliance with environmental laws and regulations could adversely impact our operations and consolidated financial results.

We are subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, the use of water, the handling, disposal and clean-up of hazardous and non-hazardous substances and wastes, natural resources and health and safety. Compliance with these legal requirements, which change frequently and have tended to become more restrictive, requires us to commit significant capital and operating resources toward permitting, emission fees, environmental monitoring, installation and operation of air and water quality control equipment and purchases of air emission allowances and/or offsets. These laws and regulations oftentimes require a lengthy and complex process for obtaining licenses, permits and approvals from governmental agencies for new, existing or modified facilities. If we fail to comply with such laws, regulations and permits, or fail to obtain and maintain necessary permits, we could be fined or otherwise sanctioned by regulators, and such fines or the cost of sanctions may not be recoverable in our prices.

Costs of compliance with environmental laws and regulations or fines or penalties resulting from non-compliance, if not recovered in our prices, could adversely impact our operations and/or consolidated financial results, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated or the number and types of assets we operate increases. We cannot estimate our compliance costs or any possible fines or penalties with certainty, or the degree to which such costs might be recovered in our prices, due to our inability to predict the requirements and timing of implementation of environmental rules or regulations.

See "Item 1. Business — Environmental Matters," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Executive Summary — Current Trends and Uncertainties — Environmental Regulation" and Notes 3 and 13 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation — KCC Proceedings — Environmental Costs" and "Commitments and Contingencies — Environmental Matters," respectively, for additional information.

In addition, we combust large amounts of fossil fuels as we produce electricity. This results in significant emissions of carbon dioxide (CO_2) and other GHGs through the operation of our power plants. Federal legislation regulates the emission of GHGs and numerous states and regions have adopted programs to stabilize or reduce GHG emissions. The Environmental Protection Agency (EPA) regulates GHGs under the Clean Air Act. In October 2015, the EPA published a rule establishing new source performance standards that limit CO_2 emissions for new, modified and reconstructed coal and natural gas fueled electric generating units to various levels per MWh depending on various characteristics of the units. In October 2015, the EPA also published a rule establishing guidelines for states to regulate CO_2 emissions from existing power plants. The standards for existing plants are known as the CPP. Under the CPP, interim emissions performance rates must be achieved beginning in 2022 and final emissions performance rates must be achieved by 2030. Legal challenges to the CPP were filed by groups of states and industry members, and in February 2016 the U.S. Supreme Court temporarily stayed implementation of the CPP. See Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies — Environmental Matters" for additional information. We believe these rules, if implemented, could have a material impact on our operations, future generation plants and/or results of operations.

Further, in the course of operating our coal generation plants, we produce CCBs, including fly ash, gypsum and bottom ash, which we must handle, recycle, process or dispose of. We historically have recycled some of our ash production, principally by selling to the aggregate industry. The EPA published a rule to regulate CCBs in April 2015, which will require additional CCB handling, processing and storage equipment and potential closure of certain ash disposal areas. See Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies — Environmental Matters" for additional information. The impact of this rule on our operations and consolidated financial results could be material.

We could be subject to penalties as a result of mandatory reliability standards, which could adversely affect our consolidated financial results.

As a result of the Energy Policy Act of 2005, owners and operators of the bulk power transmission system, including Westar Energy and KGE, are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by FERC. If we were found to be out of compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which we might not be able to recover in the prices we charge our customers. This could have a material adverse effect on our consolidated financial results.

Adverse economic conditions could adversely impact our operations and consolidated financial results.

Our operations are impacted by economic conditions. Adverse economic conditions, including a prolonged recession or capital market disruptions, may:

- reduce demand for our service;
- increase delinquencies or non-payment by customers;
- adversely impact the financial condition of suppliers, which may in turn limit our access to inventory, including coal and natural gas, or capital equipment or increase our costs; and
- increase deductibles and premiums and result in more restrictive policy terms under insurance policies regarding risks we typically insure against, or make insurance claims more difficult to collect.

A number of commercial and industrial customers have geographically dispersed facilities, and localized factors, including economic conditions, governmental or other incentives and other factors that influence customer operating or capital expenses, which may cause these customers to curtail or eliminate operations at facilities in our service territory and move them to other facilities with competitive advantages. In addition, unexpectedly strong economic conditions can result in increased costs and shortages. Any of the aforementioned events, and others we may not be able to identify, could have an adverse impact on our consolidated financial results.

We are exposed to various risks associated with the ownership and operation of Wolf Creek, any of which could adversely impact our consolidated financial results.

Through KGE's ownership interest in Wolf Creek, we are subject to the risks of nuclear generation, which include:

- the risks associated with storing, handling and disposing of radioactive materials and the current lack of a long-term off-site disposal solution for radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations;
- uncertainties with respect to the technological and financial aspects of decommissioning Wolf Creek at the end of its life; and
- costs of measures associated with public safety.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements enacted by the NRC could necessitate substantial capital expenditures at Wolf Creek.

An incident at Wolf Creek could have a material impact on our consolidated financial results. Furthermore, the non-compliance of other nuclear facilities operators with applicable regulations or the occurrence of a serious nuclear incident at other facilities anywhere in the world could result in increased regulation of the industry as a whole, which could in turn increase Wolf Creek's compliance costs and impact our consolidated financial results. Such events could also result in a shutdown of Wolf Creek.

Significant decisions about capital investments are based on forecasts of long-term demand for energy incorporating assumptions about multiple, uncertain factors. Our actual experience may differ significantly from our assumptions, which may adversely impact our consolidated financial results.

We attempt to forecast demand to determine the timing and adequacy of our energy and energy delivery resources. Long-term forecasts involve risks because they rely on assumptions we make concerning uncertain factors including weather, technological change, environmental and other regulatory requirements, economic conditions, social pressures and the responsiveness of customers' electricity demand to conservation measures and prices. Both actual future demand and our ability to satisfy such demand depend on these and other factors and may vary materially from our forecasts. If our actual experience varies significantly from our forecasts, our consolidated financial results may be adversely impacted.

Our planned capital investment for the next few years is large in relation to our size, subjecting us to significant risks.

Our anticipated capital expenditures for 2016 through 2018 are approximately $2.7 billion. In addition to risks discussed above associated with recovering capital investments through our prices, and risks associated with our reliance on the capital markets and short-term credit to fund those investments, our capital expenditure program poses risks, including, but not necessarily limited to:

- shortages, disruption in the delivery and inconsistent quality of equipment, materials and labor;
- contractor or supplier non-performance;
- delays in or failure to receive necessary permits, approvals and other regulatory authorizations;
- impacts of new and existing laws and regulations, including environmental and health and safety laws, regulations and permit requirements;
- adverse weather;
- unforeseen engineering problems or changes in project design or scope;
- environmental and geological conditions; and
- unanticipated cost increases with respect to labor or materials, including basic commodities needed for our infrastructure such as steel, copper and aluminum.

These and other factors, or any combination of them, could cause us to defer or limit our capital expenditure program and could adversely impact our consolidated financial results.

Our ability to fund our capital expenditures and meet our working capital and liquidity needs may be limited by conditions in the bank and capital markets, by our credit ratings or the market price of Westar Energy's common stock. Further, capital market conditions can cause fluctuations in the values of assets set aside for employee benefit obligations and the Wolf Creek nuclear decommissioning trust (NDT) and may increase our funding requirements related to these obligations.

To fund our capital expenditures and for working capital and liquidity, we rely on access to capital markets and to short-term credit. Disruption in capital markets, deterioration in the financial condition of the financial institutions on which we rely, any credit rating downgrade or any decrease in the market price of Westar Energy's common stock may make capital more difficult and costly for us to obtain, may restrict liquidity available to us, may require us to defer or limit capital investments or impact operations or may reduce the value of our financial assets. These could adversely impact our business and consolidated financial results, including our ability to pay dividends and to make investments or undertake programs necessary to meet regulatory mandates and customer demand.

Further, we have significant future financial obligations with respect to employee benefit obligations and the Wolf Creek NDT. The value of the assets needed to meet those obligations are subject to market fluctuations and will yield uncertain returns, which may fall below our expectations for meeting our obligations. Additionally, inflation and changes in interest rates impact the value of future liabilities. In general, when interest rates decline, the value of future liabilities increase. While the KCC allows us to implement a regulatory accounting mechanism to track certain of our employee benefit plan expenses, this mechanism does not allow us to make automatic price adjustments. Only in future rate proceedings may we be allowed to adjust our prices to reflect changes in our funding requirements. Further, the tracking mechanism for these benefit plan expenses is part of our overall rate structure, and as such, it is subject to KCC review and may be modified, limited or eliminated in the future. If these assets are not managed successfully, our consolidated financial results and cash flows could be adversely impacted.

Physical and cybersecurity breaches, criminal activity, terrorist attacks and other disruptions to our facilities or our information technology infrastructure could interfere with our operations, expose us or our customers or employees to a risk of loss and expose us to liability or regulatory penalties or cause reputational damage and other harm to our business.

We rely upon information technology networks and systems to process, transmit and store electronic information, and to manage or support a variety of business processes and activities, including the generation, transmission and distribution of electricity, supply chain functions, and the invoicing and collection of payments from our customers. We also use information technology networks and systems to record, process and summarize financial information and results of operations for internal reporting purposes and to

comply with financial reporting, legal and tax requirements. These networks and systems are in some cases owned or managed by third-party service providers. In the ordinary course of business, we collect, store and transmit sensitive data including operating information, proprietary business information belonging to us and third parties and personal information belonging to our customers and employees.

Our information technology networks and infrastructure, as well as the networks and infrastructure belonging to third-party service providers that we utilize, may be vulnerable to damage, disruptions or shutdowns due to attacks or breaches by hackers or other unauthorized third parties; error or malfeasance by one or more of our or our service providers' employees; software or hardware upgrades; additions or replacements; malicious software code; telecommunication failures; natural disasters or other catastrophic events. The occurrence of any of these events could, among other things, impact the reliability or safety of our generation, transmission and distribution systems; result in the erasure of data or render our equipment unusable; impact our ability to conduct business in the ordinary course; expose us and our customers, employees and vendors to a risk of loss or misuse of information; and result in legal claims or proceedings, liability or regulatory penalties against us, damage our reputation or otherwise harm our business. We can provide no assurance that we will identify and remedy all security or system vulnerabilities or that unauthorized access or error will be identified and remedied.

Additionally, we cannot predict the impact that any future information technology or terrorist attack may have on the energy industry in general. Our facilities could be direct targets or indirect casualties of such attacks. The effects of such attacks could include disruption to our generation, transmission and distribution systems or to the electrical grid in general, and could increase the cost of insurance coverage or result in a decline in the U.S. economy. Any of the foregoing could adversely impact our operations or financial results.

Equipment failures and other events beyond our control may cause extended or unplanned plant outages, which may adversely impact our consolidated financial results.

The generation, distribution and transmission of electricity require the use of expensive and complicated equipment, much of which is aged, and all of which requires significant ongoing maintenance. Our power plants and equipment are subject to extended outages because of equipment failure, weather, transmission system disruption, operator error, contractor or subcontractor failure and other factors. In such events, we must either produce replacement power from our other plants, which may be less efficient or more expensive to operate, purchase power from others at unpredictable and potentially higher costs in order to meet our sales obligations, or suffer outages. Such events could also limit our ability to make sales to customers. Therefore, the occurrence of extended or unplanned outages could adversely affect our consolidated financial results.

Our regulated business model may be threatened by technological advancements that could adversely affect our financial condition and results of operations.

Significant technological advancements are taking place in the electric industry, including advancements related to self-generation and distributed energy technologies such as fuel cells, micro turbines, wind turbines and solar cells, as well as related to the storage of energy produced by these systems. Adoption of these technologies may increase because of advancements or government subsidies reducing the cost of generating or storing electricity through these technologies to a level that is competitive with our current methods of generating electricity. There is also a perception that generating or storing electricity through these technologies is more environmentally friendly than generating electricity with fossil fuels. Increased adoption of these technologies could reduce electricity demand and the pool of customers from whom fixed costs are recovered, resulting in under recovery of our fixed costs. Increased self-generation and the related use of net energy metering, which allows self-generating customers to receive bill credits for surplus power, could put upward price pressure on our remaining customers. If we were unable to adjust our prices to reflect reduced electricity demand and increased self-generation and net energy metering, our financial condition and results of operations could be adversely affected.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

					Unit Capability (MW) By Owner[a]				
Name	Location	Unit No.	Year Installed	Principal Fuel	Westar Energy	KGE	Total Company Generation	Renewable Purchased Power	Total Generation and Renewable Purchased Power
Renewable Generation:									
Central Plains	Wichita County, Kansas	[a]	2009	Wind	99	—	99	—	99
Flat Ridge	Barber County, Kansas	[a]	2009	Wind	50	—	50	50	100
Cedar Bluff	Ness & Trego Counties, Kansas	[a]	2015	Wind	—	—	—	199	199
Ironwood	Ford County, Kansas	[a]	2012	Wind	—	—	—	168	168
Kay Wind	Kay County, Kansas	[a]	2015	Wind	—	—	—	200	200
Meridian Way	Cloud County, Kansas	[a]	2008	Wind	—	—	—	96	96
Post Rock	Ellsworth & Lincoln Counties, Kansas	[a]	2012	Wind	—	—	—	201	201
Rolling Meadows	Shawnee County, Kansas		2010	Landfill Gas	—	—	—	6	6
Nuclear:									
Wolf Creek Generating Station (47%):	Burlington, Kansas	1[b]	1985	Uranium	—	551	551	—	551
Coal:									
Jeffrey Energy Center (92%):	St. Marys, Kansas								
Steam Turbines		1[b]	1978	Coal	524	146	670	—	670
		2[b]	1980	Coal	509	142	651	—	651
		3[b]	1983	Coal	512	142	654	—	654
La Cygne Station (50%):	La Cygne, Kansas								
Steam Turbines		1[b]	1973	Coal	—	368	368	—	368
		2[c]	1977	Coal	—	331	331	—	331
Lawrence Energy Center:	Lawrence, Kansas								
Steam Turbines		4	1960	Coal	104	—	104	—	104
		5	1971	Coal	370	—	370	—	370
Tecumseh Energy Center:	Tecumseh, Kansas								
Steam Turbines		7	1957	Coal	65	—	65	—	65
Gas and Diesel:									
Emporia Energy Center:	Emporia, Kansas								
Combustion Turbines		1	2008	Gas	45	—	45	—	45
		2	2008	Gas	44	—	44	—	44
		3	2008	Gas	43	—	43	—	43
		4	2008	Gas	44	—	44	—	44
		5	2008	Gas	158	—	158	—	158
		6	2009	Gas	155	—	155	—	155
		7	2009	Gas	156	—	156	—	156
Gordon Evans Energy Center:	Colwich, Kansas								
Steam Turbines		1	1961	Gas	—	153	153	—	153
		2	1967	Gas	—	370	370	—	370
Combustion Turbines		1	2000	Gas	73	—	73	—	73
		2	2000	Gas	71	—	71	—	71
		3	2001	Gas	148	—	148	—	148
Hutchinson Energy Center:	Hutchinson, Kansas								
Combustion Turbines		1	1974	Gas	56	—	56	—	56
		2	1974	Gas	52	—	52	—	52
		3	1974	Gas	57	—	57	—	57
		4	1975	Diesel	70	—	70	—	70
Murray Gill Energy Center:	Wichita, Kansas								
Steam Turbines		3	1956	Gas	—	104	104	—	104
		4	1959	Gas	—	86	86	—	86
Spring Creek Energy Center:	Edmond, Oklahoma								
Combustion Turbines		1	2001	Gas	69	—	69	—	69
		2	2001	Gas	69	—	69	—	69
		3	2001	Gas	67	—	67	—	67
		4	2001	Gas	68	—	68	—	68
State Line (40%):	Joplin, Missouri								
Combined Cycle		2-1[b]	2001	Gas	62	—	62	—	62
		2-2[b]	2001	Gas	64	—	64	—	64
		2-3[b]	2001	Gas	70	—	70	—	70
Total					3,874	2,393	6,267	920	7,187

[a] *Capability (except for wind generating facilities) represents accredited net generating capacity approved by the SPP. Capability for our wind generating facilities represents the installed design capacity. Due to the intermittent nature of wind generation, these facilities are associated with a total of 152 MW of accredited generating capacity.*

[b] *Westar Energy jointly owns State Line (40%) while KGE jointly owns La Cygne unit 1 (50%) and Wolf Creek (47%). We jointly own and consolidate as a VIE 92% of JEC. Unit capacity amounts reflect our ownership and leased percentages only.*

[c] *In 1987, KGE entered into a sale-leaseback transaction involving its 50% interest in the La Cygne unit 2. We consolidate the leasing entity as a VIE as discussed in Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities."*

We own and have in service approximately 6,400 miles of transmission lines, approximately 24,000 miles of overhead distribution lines and approximately 4,900 miles of underground distribution lines.

Substantially all of our utility properties are encumbered by first priority mortgages pursuant to which bonds have been issued and are outstanding.

In 2015, Westar retired three older, smaller generating units at Lawrence Energy Center, Tecumseh Energy Center, and Hutchinson Energy Center with a combined capability of 354 MW.

ITEM 3. LEGAL PROCEEDINGS

Information on legal proceedings is set forth in Notes 3, 13 and 15 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," "Commitments and Contingencies" and "Legal Proceedings," respectively, which are incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

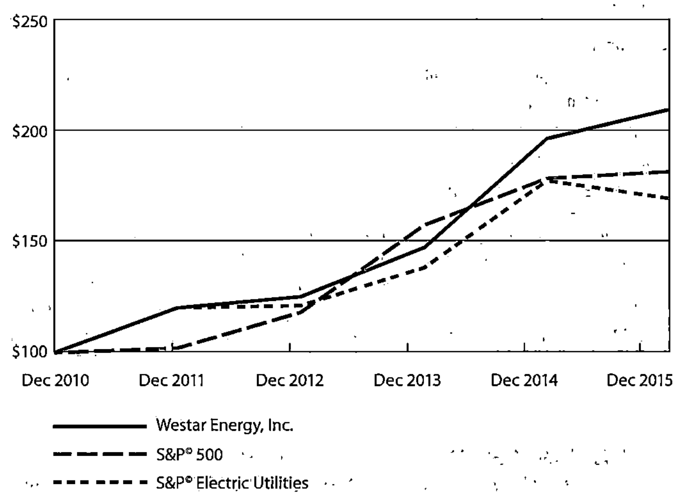
STOCK TRADING

Westar Energy's common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 17, 2016, Westar Energy had 17,670 common shareholders of record. For information regarding quarterly common stock price ranges for 2015 and 2014, see Note 19 of the Notes to Consolidated Financial Statements, "Quarterly Results (Unaudited)."

STOCK PERFORMANCE GRAPH

The following graph compares the performance of Westar Energy's common stock during the period that began on December 31, 2010, and ended on December 31, 2015, to the performance of the Standard & Poor's 500 Index (S&P 500) and the Standard & Poor's Electric Utility Index (S&P Electric Utilities). The graph assumes a $100 investment in Westar Energy's common stock and in each of the indices at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.

CUMULATIVE TOTAL RETURN
Based on an initial investment of $100 on December 31, 2010 with dividends reinvested



	Dec-2010	Dec-2011	Dec-2012	Dec-2013	Dec-2014	Dec-2015
Westar Energy, Inc.	$100	$120	$125	$147	$196	$209
S&P® 500..............	$100	$102	$118	$157	$178	$181
S&P® Electric Utilities	$100	$120	$121	$138	$177	$169

DIVIDENDS

Holders of Westar Energy's common stock are entitled to dividends when and as declared by Westar Energy's board of directors.

Quarterly dividends on common stock have historically been paid on or about the first business day of January, April, July and October to shareholders of record as of or about the ninth day of the preceding month. Westar Energy's board of directors reviews the common stock dividend policy from time to time. Among the factors the board of directors considers in determining Westar Energy's dividend policy are earnings, cash flows, capitalization ratios, regulation, competition and financial loan covenants. In 2015, Westar Energy's board of directors declared four quarterly dividends of $0.36 per share, reflecting an annual dividend of $1.44 per share, compared to four quarterly dividends of $0.35 per share in 2014, reflecting an annual dividend of $1.40 per share. On February 24, 2016, Westar Energy's board of directors declared a quarterly dividend of $0.38 per share payable to shareholders on April 1, 2016. The indicated annual dividend rate is $1.52 per share.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31,	2015	2014	2013	2012	2011
			(In Thousands)		
Income Statement Data:					
Total revenues	$ 2,459,164	$ 2,601,703	$ 2,370,654	$ 2,261,470	$ 2,170,991
Net income	301,796	322,325	300,863	282,462	236,180
Net income attributable to Westar Energy, Inc.	291,929	313,259	292,520	273,530	229,269

As of December 31,	2015	2014	2013	2012	2011
			(In Thousands)		
Balance Sheet Data:					
Total assets	$10,705,666	$ 10,288,906	$ 9,597,138	$ 9,265,231	$ 8,682,851
Long-term obligations[(a)]	3,379,219	3,433,320	3,495,292	3,124,831	2,818,030

Year Ended December 31,	2015	2014	2013	2012	2011
Common Stock Data:					
Basic earnings per share available for common stock	$ 2.11	$ 2.40	$ 2.29	$ 2.15	$ 1.95
Diluted earnings per share available for common stock	2.09	2.35	2.27	2.15	1.93
Dividends declared per share	1.44	1.40	1.36	1.32	1.28
Book value per share	25.87	25.02	23.88	22.89	22.03
Average equivalent common shares outstanding (in thousands)[(b)(c)(d)]	137,958	130,015	127,463	126,712	116,891

[(a)] Includes long-term debt, net, current maturities of long-term debt, capital leases, long-term debt of VIEs, net and current maturities of long-term debt of VIEs. See Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," for additional information regarding VIEs.
[(b)] In 2011, Westar Energy issued and sold approximately 13.6 million shares of common stock realizing proceeds of $294.9 million.
[(c)] In 2014, Westar Energy issued and sold approximately 3.4 million shares of common stock realizing proceeds of $87.7 million.
[(d)] In 2015, Westar Energy issued and sold approximately 9.7 million shares of common stock realizing proceeds of $258.0 million.

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

Certain matters discussed in Management's Discussion and Analysis are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we "believe," "anticipate," "target," "expect," "estimate," "intend" and words of similar meaning. Forward-looking statements describe our future plans, objectives, expectations or goals. See "Forward-Looking Statements" above for additional information.

EXECUTIVE SUMMARY

Description of Business

We are the largest electric utility in Kansas. We produce, transmit and sell electricity at retail to approximately 700,000 customers in Kansas under the regulation of the KCC. We also supply electric energy at wholesale to municipalities and electric cooperatives in Kansas under the regulation of FERC. We have contracts for the sale or purchase of wholesale electricity with other utilities.

Earnings Per Share

Following is a summary of our net income and basic earnings per share (EPS) for the years ended December 31, 2015 and 2014.

Year Ended December 31,	2015	2014	Change
	(Dollars In Thousands, Except Per Share Amounts)		
Net income attributable to Westar Energy, Inc.	$ 291,929	$ 313,259	$ (21,330)
Earnings per common share, basic	2.11	2.40	(0.29)

Net income attributed to common stock and basic EPS for the year ended December 31, 2015, decreased due primarily to a reduction in equity allowance for funds used during construction (AFUDC), a reduction in transmission revenues for our estimated refund obligation associated with a FERC proceeding and lower retail sales. See Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation — FERC Proceedings," for a discussion of the FERC proceeding. Also, energy marketing margins were lower in 2015 than in 2014 due to greater volatility in 2014 of wholesale power prices. Partially offsetting these reductions was a decrease in operations and maintenance expense. EPS was further reduced in 2015 by approximately $0.13 due to the issuance of common stock from our forward sales transactions. See the discussion under "— Operating Results" below for additional information.

Key Factors Affecting Our Performance

The principal business, economic and other factors that affect our operations and financial performance include:

- weather conditions;
- the economy;
- customer conservation efforts;
- the performance, operation and maintenance of our electric generating facilities and network;
- conditions in the fuel, wholesale electricity and energy markets;
- rate and other regulations and costs of addressing public policy initiatives including environmental laws and regulations;
- the availability of and our access to liquidity and capital resources; and
- capital market conditions.

Strategy

We expect to continue operating as a vertically integrated, regulated, electric utility. Significant elements of our strategy include maintaining a flexible, clean and diverse energy supply portfolio. In doing so, we continue to expand renewable generation, build and upgrade our electrical infrastructure and develop systems and programs with regard to how our customers use energy and interact with us.

Retirement of Generating Units

In 2015, we retired three older, smaller generating units at Lawrence Energy Center, Tecumseh Energy Center and Hutchinson Energy Center with a combined capability of 354 megawatts.

Current Trends and Uncertainties

Environmental Regulation

We are subject to various federal, state and local environmental laws and regulations. Environmental laws and regulations affecting our operations are overlapping, complex, subject to changes, have become more stringent over time and are expensive to implement. There are a variety of final and proposed laws and regulations that could have a material adverse effect on our operations and consolidated financial results, including those relating to:

- further regulation of GHGs by the EPA, including regulations pursuant to the CPP, and future legislation that could be proposed by the U.S. Congress;
- various proposed and expected regulations governing air emissions including those relating to National Ambient Air Quality Standards (particularly those relating to particulate matter, nitrogen oxide, ozone, CO and sulfur dioxide) and the Cross-State Air Pollution;
- the definition of Waters of the United States for purposes of the Clean Water Act; and,
- the regulation of CCB.

See Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies — Environmental Matters," for a discussion of environmental costs, laws, regulations and other contingencies.

Allowance for Funds Used During Construction

AFUDC represents the allowed cost of capital used to finance utility construction activity. We compute AFUDC by applying a composite rate to qualified construction work in progress (CWIP). We credit other income (for equity funds) and interest expense (for borrowed funds) for the amount of AFUDC capitalized as construction cost on the accompanying consolidated statements of income as follows:

Year Ended December 31,	2015	2014	2013
		(In Thousands)	
Borrowed funds	$ 3,505	$ 12,044	$ 11,706
Equity funds	2,075	17,029	14,143
Total	$ 5,580	$ 29,073	$ 25,849
Average AFUDC Rates	2.7%	6.7%	4.8%

We expect AFUDC for both borrowed funds and equity funds to fluctuate over the next several years as major projects within our capital expenditure program are being completed.

Interest Expense

We expect interest expense to increase over the next several years as we issue new debt securities to fund our capital expenditure program. We continue to believe this increase will be reflected in the prices we are permitted to charge customers, as cost of capital will be a component of future rate proceedings and is also recognized in some of the other rate adjustments we are permitted to make. In addition, short-term interest rates are extremely low by historical standards. We cannot predict to what extent these conditions will continue. See Note 9 of the Notes to Consolidated Financial Statements, "Long-Term Debt" for additional information regarding the issuance of long-term debt.

Outstanding Shares of Common Stock

We do not expect to issue additional shares of Westar Energy common stock in 2016, other than modest amounts under our dividend reinvestment plan and for the vesting of restricted share unit (RSU) awards. The shares previously priced through forward sales agreements were issued in 2015. See Note 16 of the Notes to Consolidated Financial Statements, "Common Stock," for additional information regarding our share issuances.

Customer Growth and Usage

Residential customer additions have moderated since the 2008 recession and residential electricity demand has stabilized and is growing modestly. Overall retail sales have grown as well, and are approaching pre-recession levels. We believe that our overall retail sales growth will be modest driven by industrial demand and stable residential and commercial growth. In addition, with the numerous energy efficiency policy initiatives promulgated through federal, state and local governments, as well as industry initiatives, environmental regulations and the need to strengthen and modernize the grid, which will increase price pressure, we believe customers will continue to adopt more energy efficiency and conservation measures, which will slow or possibly suppress the growth of demand for electricity.

2016 Outlook

In 2016, we expect to maintain our current business strategy and regulatory approach. Assuming normal weather, we expect 2016 retail electricity sales to be in line with our projected retail customer growth of about 0.5%.

Absent increases in SPP transmission expense and property tax expense, which are increasing at a much higher rate than inflation and are offset with higher revenues pursuant to our regulatory mechanisms, we anticipate operating and maintenance and selling, general and administrative expenses to be relatively flat in 2016 as compared to 2015. To help fund our capital spending as provided under "— Future Cash Requirements" below, in 2016 we may issue long-term debt, and utilize short-term borrowings by issuing commercial paper until permanent financing is in place.

CRITICAL ACCOUNTING ESTIMATES

Our discussion and analysis of financial condition and results of operations are based on our consolidated financial statements, which have been prepared in conformity with Generally Accepted Accounting Principles (GAAP). Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies," contains a summary of our significant accounting policies, many of which require the use of estimates and assumptions by management. The policies highlighted below have an impact on our reported results that may be material due to the levels of judgment and subjectivity necessary to account for uncertain matters or their susceptibility to change.

Regulatory Accounting

We apply accounting standards that recognize the economic effects of rate regulation. Accordingly, we have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in our prices. Regulatory liabilities represent probable future reductions in revenue or refunds to customers.

The deferral of costs as regulatory assets is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific regulatory orders, regulatory precedent and the current regulatory environment. If we deem it no longer probable that we would recover such costs, we would record a charge against income in the amount of the related regulatory assets.

As of December 31, 2015, we had recorded regulatory assets currently subject to recovery in future prices of approximately $860.9 million and regulatory liabilities of $292.8 million, as discussed in greater detail in Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation."

Pension and Post-retirement Benefit Plans Actuarial Assumptions

We and Wolf Creek calculate our pension benefit and post-retirement medical benefit obligations and related costs using actuarial concepts within the guidance provided by GAAP.

In accounting for our retirement plans and post-retirement benefits, we make assumptions regarding the valuation of benefit obligations and the performance of plan assets. The reported costs of our pension plans are impacted by estimates regarding earnings on plan assets, contributions to the plan, discount rates used to determine our projected benefit obligation and pension costs and employee demographics including age, life expectancy and compensation levels and employment periods. Changes in these assumptions result primarily in changes to regulatory assets, regulatory liabilities or the amount of related pension and post-retirement benefit liabilities reflected on our consolidated balance sheets. Such changes may also require cash contributions.

The following table shows the impact of a 0.5% change in our pension plan discount rate, salary scale and rate of return on plan assets.

Actuarial Assumption	Change in Assumption	Change in Projected Benefit Obligation[a]	Annual Change in Projected Pension Costs[a]
		(Dollars In Thousands)	
Discount rate	0.5% decrease	$ 87,042	$ 8,008
	0.5% increase	(77,767)	(7,254)
Compensation	0.5% decrease	(17,147)	(3,319)
	0.5% increase	18,219	3,551
Rate of return on plan assets	0.5% decrease	—	3,930
	0.5% increase	—	(3,930)

[a] *Increases or decreases due to changes in actuarial assumptions result primarily in changes to regulatory assets and liabilities.*

The following table shows the impact of a 0.5% change in the discount rate and rate of return on plan assets and a 1% change in the annual medical trend on our post-retirement benefit plans.

Actuarial Assumption	Change in Assumption	Change in Projected Benefit Obligation[a]	Annual Change in Projected Post-retirement Costs[a]
		(Dollars In Thousands)	
Discount rate	0.5% decrease	$ 7,587	$ 374
	0.5% increase	(7,081)	(347)
Rate of return on plan assets	0.5% decrease	—	570
	0.5% increase	—	(570)
Annual medical trend	1.0% decrease	97	15
	1.0% increase	(95)	(15)

[a] *Increases or decreases due to changes in actuarial assumptions result primarily in changes to regulatory assets and liabilities.*

Revenue Recognition

We record revenue at the time we deliver electricity to customers. We determine the amounts delivered to individual customers through systematic monthly readings of customer meters. At the end of each month, we estimate how much electricity we have delivered since the prior meter reading and record the corresponding unbilled revenue.

Our unbilled revenue estimate is affected by factors including fluctuations in energy demand, weather, line losses and changes in the composition of customer classes. We recorded estimated unbilled revenue of $66.0 million as of December 31, 2015 and $61.0 million as of December 31, 2014.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under this method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over

the lives of the related properties as required by tax laws and regulatory practices. We recognize production tax credits in the year that electricity is generated to the extent that realization of such benefits is more likely than not.

We record deferred tax assets to the extent capital losses, operating losses or tax credits will be carried forward to future periods. However, when we believe based on available evidence that we do not, or will not, have sufficient future capital gains or taxable income in the appropriate taxing jurisdiction to realize the entire benefit during the applicable carryforward period, we record a valuation allowance against the deferred tax asset.

The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Accordingly, we must make judgments regarding income tax exposure. Interpretations of and guidance surrounding income tax laws and regulations change over time. As a result, changes in our judgments can materially affect amounts we recognize in our consolidated financial statements. See Note 10, "Taxes," for additional detail on our accounting for income taxes.

Bonus Depreciation Extension

In December 2015, Congress passed and the President signed into law the "Protecting Americans from Tax Hikes (PATH) Act of 2015" which, among other things, extended bonus depreciation for an additional five-year period encompassing the years 2015 through 2019. Bonus depreciation provides for additional first-year tax depreciation allowance for qualifying property. As a result of the five-year extension in 2015, should we continue to fully utilize the depreciation deductions under bonus depreciation, certain tax credits provided by the State of Kansas related to investments in utility plant may not be realizable requiring us to record a valuation allowance. At this time, we expect to utilize bonus depreciation deductions to the extent necessary to fully utilize the aforementioned Kansas tax credits.

Asset Retirement Obligations

Legal Liability

We have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of the asset retirement obligation (ARO) is capitalized and depreciated over the remaining life of the asset. We estimate our AROs based on the fair value of the AROs we incurred at the time the related long-lived assets were either acquired, placed in service or when regulations establishing the obligation became effective.

We initially recorded AROs at fair value for the estimated cost to decommission Wolf Creek (our 47% share), retire our wind generating facilities, dispose of asbestos insulating material at our power plants, remediate ash disposal ponds and dispose of polychlorinated biphenyl contaminated oil. In determining our AROs, we make assumptions regarding probable future disposal costs. A change in these assumptions could have a significant impact on the AROs reflected on our consolidated balance sheets.

As of December 31, 2015 and 2014, we have recorded AROs of $275.3 million and $230.7 million, respectively. For additional information on our legal AROs, see Note 14 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations."

Contingencies and Litigation

We and our subsidiaries are involved in various legal, environmental and regulatory proceedings, and we have estimated the probable cost for the resolution of these proceedings. These estimates are based on an analysis of potential results, assuming a combination of litigation and settlement strategies. It is possible that our future consolidated financial results could be materially affected by changes in our assumptions. See Notes 3, 13 and 15 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulations", "Commitments and Contingencies," and "Legal Proceedings," for additional information.

OPERATING RESULTS

We evaluate operating results based on EPS. We have various classifications of revenues, defined as follows:

Retail: Sales of electricity to residential, commercial and industrial customers. Classification of customers as residential, commercial or industrial requires judgment and our classifications may be different from other companies. Assignment of tariffs is not dependent on classification. Other retail sales of electricity include lighting for public streets and highways, net of revenue subject to refund.

Wholesale: Sales of electricity to electric cooperatives, municipalities, other electric utilities and RTOs, the prices for which are either based on cost or prevailing market prices as prescribed by FERC authority. Revenues from these sales are either included in the retail energy cost adjustment or used in the determinations of base rates at the time of our next general rate review.

Transmission: Reflects transmission revenues, including those based on tariffs with the SPP.

Other: Miscellaneous electric revenues including ancillary service revenues and rent from electric property leased to others. This category also includes transactions unrelated to the production of our generating assets and fees we earn for services that we provide for third parties.

Electric utility revenues are impacted by things such as rate regulation, fuel costs, technology, customer behavior, the economy and competitive forces. Changing weather also affects the amount of electricity our customers use as electricity sales are seasonal. As a summer peaking utility, the third quarter typically accounts for our greatest electricity sales. Hot summer temperatures and cold winter temperatures prompt more demand, especially among residential and commercial customers, and to a lesser extent, industrial customers. Mild weather reduces customer demand. Our wholesale revenues are impacted by, among other factors, demand, cost and availability of fuel and purchased power, price volatility, available generation capacity, transmission availability and weather.

2015 Compared to 2014

Below we discuss our operating results for the year ended December 31, 2015, compared to the results for the year ended December 31, 2014. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

Year Ended December 31,	2015	2014	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 768,618	$ 793,586	$ (24,968)	(3.1)
Commercial	712,400	727,964	(15,564)	(2.1)
Industrial	400,687	414,997	(14,310)	(3.4)
Other retail	(17,155)	(24,180)	7,025	29.1
Total Retail Revenues	1,864,550	1,912,367	(47,817)	(2.5)
Wholesale	318,371	392,730	(74,359)	(18.9)
Transmission	241,835	256,838	(15,003)	(5.8)
Other	34,408	39,768	(5,360)	(13.5)
Total Revenues	2,459,164	2,601,703	(142,539)	(5.5)
OPERATING EXPENSES:				
Fuel and purchased power	561,065	705,450	(144,385)	(20.5)
SPP network transmission costs	229,043	218,924	10,119	4.6
Operating and maintenance	330,289	367,188	(36,899)	(10.0)
Depreciation and amortization	310,591	286,442	24,149	8.4
Selling, general and administrative	250,278	250,439	(161)	(0.1)
Taxes other than income tax	156,901	140,302	16,599	11.8
Total Operating Expenses	1,838,167	1,968,745	(130,578)	(6.6)
INCOME FROM OPERATIONS	620,997	632,958	(11,961)	(1.9)
OTHER INCOME (EXPENSE):				
Investment earnings	7,799	10,622	(2,823)	(26.6)
Other income	19,438	31,522	(12,084)	(38.3)
Other expense	(17,636)	(18,389)	753	4.1
Total Other Income	9,601	23,755	(14,154)	(59.6)
Interest expense	176,802	183,118	(6,316)	(3.4)
INCOME BEFORE INCOME TAXES	453,796	473,595	(19,799)	(4.2)
Income tax expense	152,000	151,270	730	0.5
NET INCOME	301,796	322,325	(20,529)	(6.4)
Less: Net income attributable to noncontrolling interests	9,867	9,066	801	8.8
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 291,929	$ 313,259	$ (21,330)	(6.8)
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 2.11	$ 2.40	$ (0.29)	(12.1)
DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 2.09	$ 2.35	$ (0.26)	(11.1)

Rate Review Agreement

In September 2015, the KCC issued an order in our state general rate review allowing us to adjust our prices to include, among other things, additional investment in La Cygne environmental upgrades and investment to extend the life of Wolf Creek. The new prices were effective late October 2015 and are expected to increase our annual retail revenues by approximately $78.3 million.

Gross Margin

Fuel and purchased power costs fluctuate with electricity sales and unit costs. As permitted by regulators, we adjust our retail prices to reflect changes in the costs of fuel and purchased power. Fuel and purchased power costs for wholesale customers are recovered at prevailing market prices or based on a predetermined formula with a price adjustment approved by FERC. As a result, changes in fuel and purchased power costs are offset in revenues with minimal impact on net income. In addition, SPP network transmission costs fluctuate due primarily to investments by us and other members of the SPP for upgrades to the transmission grid within the SPP RTO. As with fuel and purchased power costs, changes in SPP network transmission costs are mostly reflected in the prices we charge customers with minimal impact on net income. For these reasons, we believe gross margin is useful for understanding and analyzing changes in our operating performance from one period to the next. We calculate gross margin as total revenues, including transmission revenues, less the sum of fuel and purchased power costs and amounts billed by the SPP for network transmission costs. Accordingly, gross margin reflects transmission revenues and costs on a net basis. The following table summarizes our gross margin for the years ended December 31, 2015 and 2014.

Year Ended December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Revenues	$ 2,459,164	$ 2,601,703	$ (142,539)	(5.5)
Less: Fuel and purchased power expense	561,065	705,450	(144,385)	(20.5)
SPP network transmission costs	229,043	218,924	10,119	4.6
Gross Margin	$ 1,669,056	$ 1,677,329	$ (8,273)	(0.5)

The following table reflects changes in electricity sales for the years ended December 31, 2015 and 2014. No electricity sales are shown for transmission or other as they are not directly related to the amount of electricity we sell.

Year Ended December 31,	2015	2014	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,364	6,580	(216)	(3.3)
Commercial	7,500	7,521	(21)	(0.3)
Industrial	5,502	5,601	(99)	(1.8)
Other retail	84	86	(2)	(2.3)
Total Retail	19,450	19,788	(338)	(1.7)
Wholesale	8,492	9,544	(1,052)	(11.0)
Total	27,942	29,332	(1,390)	(4.7)

Gross margin decreased due primarily to an estimated $13.8 million transmission revenues refund obligation associated with a FERC proceeding. See Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation — FERC Proceedings," for a discussion of this proceeding. Energy marketing margin decreased $11.2 million due to greater volatility in 2014 of wholesale power prices. Also contributing to the decrease in gross margin was lower retail electricity sales. The lower residential and commercial electric sales were due to warm winter weather. During 2015, there were approximately 19% fewer heating degree days compared to 2014. The lower industrial sales were due to a few of our larger customers who experienced weaker global demand for their products.

Income from operations is the most directly comparable measure to our presentation of gross margin that is calculated and presented in accordance with GAAP in our consolidated statements of income. Our presentation of gross margin should not be considered in isolation or as a substitute for income from operations. Additionally, our presentation of gross margin may not be comparable to similarly titled measures reported by other companies. The following table reconciles income from operations with gross margin for the years ended December 31, 2015 and 2014.

Year Ended December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Gross margin	$ 1,669,056	$ 1,677,329	$ (8,273)	(0.5)
Less: Operating and maintenance expense	330,289	367,188	(36,899)	(10.0)
Depreciation and amortization expense	310,591	286,442	24,149	8.4
Selling, general and administrative expense	250,278	250,439	(161)	(0.1)
Taxes other than income tax	156,901	140,302	16,599	11.8
Income from operations	$ 620,997	$ 632,958	$ (11,961)	(1.9)

Operating Expenses and Other Income and Expense Items

Year Ended December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Operating and maintenance expense	$ 330,289	$ 367,188	$ (36,899)	(10.0)

Operating and maintenance expense decreased due principally to:

- lower transmission and distribution operations and maintenance expense of $14.8 million due partially to focus on capital replacement for longer term grid resiliency;
- lower costs at our coal fired plants of $10.5 million, which were principally the result of higher operating and maintenance costs incurred during a 2014 scheduled outage at JEC; and
- lower costs at Wolf Creek of $10.3 million, which were principally the result of higher operating and maintenance costs incurred during a 2014 scheduled outage.

Year Ended December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Depreciation and amortization expense	$ 310,591	$ 286,442	$ 24,149	8.4

Depreciation and amortization expense increased due to additions at our power plants, including air quality controls, additions at Wolf Creek to enhance reliability and the addition of transmission facilities. Depreciation related to environmental equipment placed in-service at La Cygne, as approved by the KCC, was deferred until new retail prices became effective in late October 2015.

Year Ended December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Selling, general and administrative expense	$ 250,278	$ 250,439	$ (161)	(0.1)

Selling, general and administrative expense decreased due primarily to a reduction of $4.2 million in amortization for previously deferred amounts with various energy efficiency programs; however, partially offsetting this decrease was higher labor and employee benefit costs of $5.1 million partially related to restructuring charges.

Year Ended December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Taxes other than income tax	$ 156,901	$ 140,302	$ 16,599	11.8

Taxes other than income tax increased due primarily to an increase of $16.9 million in property tax expense. This increase is mostly offset in retail revenue.

Year Ended December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Investment earnings	$ 7,799	$ 10,622	$ (2,823)	(26.6)

Investment earnings decreased due primarily to recording a $2.2 million lower gain on a trust to secure certain retirement benefit obligations.

Year Ended December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Other income	$ 19,438	$ 31,522	$ (12,084)	(38.3)

Other income decreased due primarily to our having recorded about $15.0 million less in equity AFUDC due primarily to completion of major construction projects. The decrease was partially offset by our having recorded $2.7 million more in corporate-owned life insurance (COLI) benefits.

Year Ended December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Interest expense	$ 176,802	$ 183,118	$ (6,316)	(3.4)

Interest expense decreased due primarily to a decrease in long-term interest expense of $14.7 million due to refinancing debt. However, partially offsetting this decrease was a reduction in debt AFUDC of $8.5 million primarily due to reduced CWIP.

2014 Compared to 2013

Below we discuss our operating results for the year ended December 31, 2014, compared to the results for the year ended December 31, 2013. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

Year Ended December 31,	2014	2013	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 793,586	$ 728,852	$ 64,734	8.9
Commercial	727,964	667,106	60,858	9.1
Industrial	414,997	374,825	40,172	10.7
Other retail	(24,180)	8,939	(33,119)	(370.5)
Total Retail Revenues	1,912,367	1,779,722	132,645	7.5
Wholesale	392,730	348,239	44,491	12.8
Transmission	256,838	210,281	46,557	22.1
Other	39,768	32,412	7,356	22.7
Total Revenues	2,601,703	2,370,654	231,049	9.7
OPERATING EXPENSES:				
Fuel and purchased power	705,450	634,797	70,653	11.1
SPP network transmission costs	218,924	178,604	40,320	22.6
Operating and maintenance	367,188	359,060	8,128	2.3
Depreciation and amortization	286,442	272,593	13,849	5.1
Selling, general and administrative	250,439	224,133	26,306	11.7
Taxes other than income tax	140,302	122,282	18,020	14.7
Total Operating Expenses	1,968,745	1,791,469	177,276	9.9
INCOME FROM OPERATIONS	632,958	579,185	53,773	9.3
OTHER INCOME (EXPENSE):				
Investment earnings	10,622	10,056	566	5.6
Other income	31,522	35,609	(4,087)	(11.5)
Other expense	(18,389)	(18,099)	(290)	(1.6)
Total Other Income (Expense)	23,755	27,566	(3,811)	(13.8)
Interest expense	183,118	182,167	951	0.5
INCOME BEFORE INCOME TAXES	473,595	424,584	49,011	11.5
Income tax expense	151,270	123,721	27,549	22.3
NET INCOME	322,325	300,863	21,462	7.1
Less: Net income attributable to noncontrolling interests	9,066	8,343	723	8.7
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 313,259	$ 292,520	$ 20,739	7.1
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 2.40	$ 2.29	$ 0.11	4.8
DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 2.35	$ 2.27	$ 0.08	3.5

Rate Review Agreement

In November 2013, the KCC issued an order allowing us to adjust our prices to include the additional investment in the La Cygne environmental upgrades, as discussed below, and to reflect cost reductions elsewhere. The new prices were expected to increase our annual retail revenues by approximately $30.7 million.

Gross Margin

The following table summarizes our gross margin for the years ended December 31, 2014 and 2013.

Year Ended December 31,	2014	2013	Change	% Change
	(Dollars In Thousands)			
Revenues	$ 2,601,703	$ 2,370,654	$ 231,049	9.7
Less: Fuel and purchased power expense	705,450	634,797	70,653	11.1
SPP network transmission costs	218,924	178,604	40,320	22.6
Gross Margin	$ 1,677,329	$ 1,557,253	$ 120,076	7.7

The following table reflects changes in electricity sales for the years ended December 31, 2014 and 2013. No electricity sales are shown for transmission or other as they are not directly related to the amount of electricity we sell.

Year Ended December 31,	2014	2013	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,580	6,523	57	0.9
Commercial	7,521	7,480	41	0.5
Industrial	5,601	5,407	194	3.6
Other retail	86	86	—	—
Total Retail	19,788	19,496	292	1.5
Wholesale	9,544	8,593	951	11.1
Total	29,332	28,089	1,243	4.4

Gross margin increased due primarily to higher retail revenues, principally the result of higher retail prices. Average retail prices were about 6% higher than 2013, resulting from recovery of investments we made in our transmission infrastructure and air quality controls at our power plants. Retail revenues were also impacted by more electricity sales resulting principally from increased sales to industrial customers.

The following table reconciles income from operations with gross margin for the years ended December 31, 2014 and 2013.

Year Ended December 31,	2014	2013	Change	% Change
	(Dollars In Thousands)			
Gross margin	$ 1,677,329	$ 1,557,253	$ 120,076	7.7
Less: Operating and maintenance expense	367,188	359,060	8,128	2.3
Depreciation and amortization expense	286,442	272,593	13,849	5.1
Selling, general and administrative expense	250,439	224,133	26,306	11.7
Taxes other than income tax	140,302	122,282	18,020	14.7
Income from operations	$ 632,958	$ 579,185	$ 53,773	9.3

Operating Expenses and Other Income and Expense Items

Year Ended December 31,	2014	2013	Change	% Change
	(Dollars In Thousands)			
Operating and maintenance expense	$ 367,188	$ 359,060	$ 8,128	2.3

Operating and maintenance expense increased due principally to:

- a $6.4 million increase in operating and maintenance costs at our plants primarily for planned outages at our coal fired plants;
- a $4.3 million increase in operating and maintenance costs to enhance reliability of our transmission systems; and,
- an approximately $3.9 million increase in costs at Wolf Creek attributable primarily to a planned outage in the first and second quarters of 2014; however,
- partially offsetting these increases was a $7.8 million decrease in amounts expensed for previously deferred storm costs.

Year Ended December 31,	2014	2013	Change	% Change
	(Dollars In Thousands)			
Depreciation and amortization expense	$ 286,442	$ 272,593	$ 13,849	5.1

Depreciation and amortization expense increased due to plant additions, including air quality controls, and transmission facilities as well as increased amortization related primarily to implementing new software systems.

Year Ended December 31,	2014	2013	Change	% Change
	(Dollars In Thousands)			
Selling, general and administrative expense	$ 250,439	$ 224,133	$ 26,306	11.7

Selling, general and administrative expense increased due primarily to:

- higher labor and employee benefit costs of $10.6 million;
- a $6.1 million increase in fees related primarily to implementing new software systems; and,
- an increase in the allowance for uncollectible accounts of $2.7 million.

Year Ended December 31,	2014	2013	Change	% Change
	(Dollars In Thousands)			
Taxes other than income tax	$ 140,302	$ 122,282	$ 18,020	14.7

Taxes other than income tax increased due primarily to a $16.2 million increase in property taxes, which are offset in retail revenues.

Year Ended December 31,	2014	2013	Change	% Change
	(Dollars In Thousands)			
Other income	$ 31,522	$ 35,609	$ (4,087)	(11.5)

Other income decreased due primarily to our having recorded about $6.9 million less in COLI benefits. The decrease was partially offset by our having recorded $2.9 million more in equity AFUDC.

Year Ended December 31,	2014	2013	Change	% Change
	(Dollars In Thousands)			
Income tax expense	$ 151,270	$ 123,721	$ 27,549	22.3

Income tax expense increased due primarily to higher income before income taxes.

Financial Condition

A number of factors affected amounts recorded on our balance sheet as of December 31, 2015, compared to December 31, 2014.

As of December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Fuel inventory and supplies	$ 301,294	$ 247,406	$ 53,888	21.8

Coal inventory increased $44.3 million due to improved rail performance and due to reduced coal plant utilization. In addition, materials and supplies increased $10.9 million due primarily to improved substation reliability.

As of December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Property, plant and equipment, net	$ 8,524,902	$ 8,162,908	$ 361,994	4.4

Property, plant and equipment, net of accumulated depreciation, increased due primarily to plant additions for air quality controls, additional transmission facilities, additions for our wind energy project and revisions to our AROs.

As of December 31,	2015	2014	Change	% Change
	(Dollars In Thousands)			
Regulatory assets	$ 860,918	$ 859,778	$ 1,140	0.1
Regulatory liabilities	292,811	343,485	(50,674)	(14.8)
Net regulatory assets	$ 568,107	$ 516,293	$ 51,814	10.0

Total regulatory assets increased due primarily to the following items:

- a $60.6 million increase in debt reacquisition costs related to the redemption of Westar Energy first mortgage bonds;
- a $15.4 million increase in deferred depreciation expense and carrying costs related to our capital investment associated with environmental upgrades at La Cygne;
- a $5.9 million increase in conditional AROs;
- a $5.4 million increase in amounts deferred for Wolf Creek refueling and maintenance outages;
- a $5.0 million increase in amounts deferred for property taxes; however,
- partially offsetting these increases was an $81.8 million decrease in deferred employee benefit costs, due principally to an increase in the discount rates used to calculate our and Wolf Creek's pension benefit obligations and the adoption of updated mortality tables; and
- a $9.9 million decrease in amounts due from customers for future income taxes.

Total regulatory liabilities decreased due primarily to the following reasons:

- a $34.4 million decrease in amounts collected but not yet spent to dispose of plant assets; and
- a $20.6 million decrease in refund obligations related to amounts we have collected from our customers in excess of our actual cost of fuel and purchased power; however,
- partially offsetting these decreases was a $16.7 million increase in pension and other post-retirement benefit costs.

As of December 31,	2015	2014	Change	% Change
		(Dollars In Thousands)		
Short-term debt	$ 250,300	$ 257,600	$ (7,300)	(2.8)

Short-term debt decreased due to decreased issuances of commercial paper.

As of December 31,	2015	2014	Change	% Change
		(Dollars In Thousands)		
Long-term debt, net	$ 3,163,950	$ 3,187,080	$ (23,130)	(0.7)

In 2015, Westar Energy issued $550.0 million in principal amount of first mortgage bonds. Proceeds of these issuances were used to retire $575.0 million in principal amount of Westar Energy first mortgage bonds. For more information on our long-term debt, see Note 9 of the Notes to Consolidated Financial Statements, "Long-term Debt."

As of December 31,	2015	2014	Change	% Change
		(Dollars In Thousands)		
Current maturities of long-term debt of variable interest entities	$ 28,309	$ 27,933	$ 376	1.3
Long-term debt of variable interest entities	138,097	166,565	(28,468)	(17.1)
Total long-term debt of variable interest entities	$ 166,406	$ 194,498	$ (28,092)	(14.4)

Total long-term debt of VIEs decreased due principally to the VIEs that hold the JEC and La Cygne leasehold interests having made principal payments totaling $27.9 million.

As of December 31,	2015	2014	Change	% Change
		(Dollars In Thousands)		
Deferred income tax liabilities	$ 1,591,430	$ 1,445,851	$ 145,579	10.1

Long-term deferred income tax liabilities increased due primarily to the use of bonus and accelerated depreciation methods during the year.

As of December 31,	2015	2014	Change	% Change
		(Dollars In Thousands)		
Accrued employee benefits	$ 462,304	$ 532,622	$ (70,318)	(13.2)

Accrued employee benefits decreased due primarily to lower pension and post-retirement benefit obligations as a result of increases in the discount rates used to calculate our and Wolf Creek's pension benefit obligations and the adoption of updated mortality tables.

As of December 31,	2015	2014	Change	% Change
		(Dollars In Thousands)		
Asset retirement obligations	$ 275,285	$ 230,668	$ 44,617	19.3

AROs increased due primarily to a new ARO of approximately $34.4 million as a result of the CCB regulation published by the EPA. See Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies." and Note 14 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations," for additional information.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Available sources of funds to operate our business include internally generated cash, short-term borrowings under Westar Energy's commercial paper program and revolving credit facilities and access to capital markets. We expect to meet our day-to-day cash requirements including, among other items, fuel and purchased power, dividends, interest payments, income taxes and pension contributions, using primarily internally generated cash and short-term borrowings. To meet the cash requirements for our capital investments, we expect to use internally generated cash, short-term borrowings and proceeds from the issuance of debt and equity securities in the capital markets. When such balances are of sufficient size and it makes economic sense to do so, we also use proceeds from the issuance of long-term debt and equity securities to repay short-term borrowings, which are principally related to investments in capital equipment and the redemption of bonds and for working capital and general corporate purposes. In 2016, we expect to continue our significant capital spending program and plan to contribute to our pension trust. We continue to believe that we will have the ability to pay dividends. Uncertainties affecting our ability to meet cash requirements include, among others, factors affecting revenues described in "Item 1A. Risk Factors" and "— Operating Results" above, economic conditions, regulatory actions, compliance with environmental regulations and conditions in the capital markets. For additional information on our future cash requirements, see "— Future Cash Requirements" below.

Capital Structure

As of December 31, 2015 and 2014, our capital structure, excluding short-term debt, was as follows:

As of December 31,	2015	2014
Common equity	52%	49%
Noncontrolling interests	<1%	<1%
Long-term debt, including VIEs	48%	51%

Short-Term Borrowings

Westar Energy maintains a commercial paper program pursuant to which it may issue commercial paper up to a maximum aggregate amount outstanding at any one time of $1.0 billion. This program is supported by Westar Energy's revolving credit facilities. Maturities of commercial paper issuances may not exceed 365 days from the date of issuance and proceeds from such issuances will be used to temporarily fund capital expenditures, to redeem debt on an interim basis, for working capital and/or for other general corporate purposes. As of February 17, 2016, Westar Energy had $308.9 million of commercial paper issued and outstanding.

Westar Energy has two revolving credit facilities in the amounts of $730.0 million and $270.0 million. In September 2015, Westar Energy extended the term of the $730.0 million facility by one year

to terminate in September 2019, $20.7 million of which will expire in September 2017. The $270.0 million facility will expire in February 2017. As long as there is no default under the facilities, the $730.0 million facility may be extended an additional year and the aggregate amount of borrowings under the $730.0 million and $270.0 million facilities may be increased to $1.0 billion and $400.0 million, respectively, subject to lender participation. All borrowings under the facilities are secured by KGE first mortgage bonds. Total combined borrowings under the revolving credit facilities and the commercial paper program may not exceed $1.0 billion at any given time. As of February 17, 2016, no amounts were borrowed and $19.2 million of letters of credit had been issued under the $730.0 million facility. No amounts were borrowed and no letters of credit were issued under the $270.0 million facility as of the same date.

A default by Westar Energy or KGE under other indebtedness totaling more than $25.0 million would be a default under both revolving credit facilities. Westar Energy is required to maintain a consolidated indebtedness to consolidated capitalization ratio of 65% or less at all times. At December 31, 2015, our ratio was 49%. See Note 8 of the Notes to Consolidated Financial Statements, "Short-Term Debt," for additional information regarding our short-term borrowings.

Long-Term Debt Financing

As of December 31, 2015, we had $121.9 million of variable rate, tax-exempt bonds outstanding. While the interest rates for these bonds have been extremely low, we continue to monitor the credit markets and evaluate our options with respect to these bonds.

In February 2016, KGE, as lessee to the La Cygne sale-leaseback, effected a refunding of $162.1 million in outstanding bonds held by the trustee of the lease maturing March 2021. The stated interest rate of the bonds was reduced from 5.647% to 2.398%. See Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," for additional information regarding our La Cygne sale-leaseback.

In November 2015, Westar Energy issued $250.0 million in principal amount of first mortgage bonds bearing stated interest at 3.25% and maturing December 2025. Concurrently, Westar Energy issued $300.0 million in principal amount of first mortgage bonds bearing stated interest at 4.25% and maturing December 2045.

Also in November 2015, Westar Energy redeemed $300.0 million in principal amount of first mortgage bonds bearing stated interest at 8.625% maturing in December 2018 for $360.9 million which included a call premium. The call premium was recorded as a regulatory asset and is being amortized over the term of the new bonds.

In August 2015, Westar Energy redeemed $150.0 million in principal amount of first mortgage bonds bearing stated interest at 5.875% and maturing July 2036.

In January 2015, Westar Energy redeemed $125.0 million in principal amount of first mortgage bonds bearing stated interest at 5.95% and maturing January 2035.

The Westar Energy and KGE mortgages each contain provisions restricting the amount of first mortgage bonds that can be issued by each entity. We must comply with such restrictions prior to the issuance of additional first mortgage bonds or other secured indebtedness.

Under the Westar Energy mortgage, the issuance of bonds is subject to limitations based on the amount of bondable property additions. In addition, so long as any bonds issued prior to January 1, 1997, remain outstanding, the mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless Westar Energy's unconsolidated net earnings available for interest, depreciation and property retirement (which as defined, does not include earnings or losses attributable to the ownership of securities of subsidiaries), for a period of 12 consecutive months within 15 months preceding the issuance, are not less than the greater of twice the annual interest charges on or 10% of the principal amount of all first mortgage bonds outstanding after giving effect to the proposed issuance. As of December 31, 2015, approximately $851.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

Under the KGE mortgage, the amount of first mortgage bonds authorized is limited to a maximum of $3.5 billion and the issuance of bonds is subject to limitations based on the amount of bondable property additions. In addition, the mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless KGE's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than either two and one-half times the annual interest charges on or 10% of the principal amount of all KGE first mortgage bonds outstanding after giving effect to the proposed issuance. As of December 31, 2015, approximately $1.5 billion principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

Some of our debt instruments contain restrictions that require us to maintain leverage ratios as defined in the credit agreements. We calculate these ratios in accordance with the agreements and they are used to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2015.

Impact of Credit Ratings on Debt Financing

Moody's Investors Service (Moody's) and Standard & Poor's Ratings Services (S&P) are independent credit-rating agencies that rate our debt securities. These ratings indicate each agency's assessment of our ability to pay interest and principal when due on our securities.

In general, more favorable credit ratings increase borrowing opportunities and reduce the cost of borrowing. Under Westar Energy's revolving credit facilities and commercial paper program, our cost of borrowings is determined in part by credit ratings. However, Westar Energy's ability to borrow under the credit facilities and commercial paper program are not conditioned on maintaining a particular credit rating. We may enter into new credit agreements that contain credit rating conditions, which could affect our liquidity and/or our borrowing costs.

Factors that impact our credit ratings include a combination of objective and subjective criteria. Objective criteria include typical financial ratios, such as total debt to total capitalization and funds from operations to total debt, among others, future capital expenditures and our access to liquidity including committed lines of credit. Subjective criteria include such items as the quality and credibility of management, the political and regulatory environment we operate in and an assessment of our governance and risk management practices.

As of February 17, 2016, our ratings with the agencies are as shown in the table below.

	Westar Energy First Mortgage Bond Rating	KGE First Mortgage Bond Rating	Westar Energy Commercial Paper	Rating Outlook
Moody's	A2	A2	P-2	Stable
S&P	A	A	A-2	Stable

Common Stock

Westar Energy's Restated Articles of Incorporation, as amended, provide for 275.0 million authorized shares of common stock. As of December 31, 2015, Westar Energy had 141.4 million shares issued and outstanding.

In September 2013, Westar Energy entered into two forward sale agreements with two banks. Under the terms of the agreements, the banks, as forward sellers, borrowed 8.0 million shares of Westar Energy's common stock from third parties and sold them to a group of underwriters for $31.15 per share. Pursuant to over-allotment options granted to the underwriters, the underwriters purchased in October 2013 an additional 0.9 million shares from the banks as forward sellers, increasing the total number of shares under the forward sale agreements to approximately 8.9 million. The underwriters received a commission equal to 3.5% of the sales price of all shares sold under each agreement.

In March 2013, Westar Energy entered into a three-year sales agency financing agreement and master forward sale agreement with a bank. The maximum amount that Westar Energy may offer and sell under the March 2013 agreements is the lesser of an aggregate of $500.0 million or approximately 25.0 million shares, subject to adjustment for share splits, share combinations and share dividends. Under the terms of the sales agency financing agreement, Westar Energy may offer and sell shares of its common stock from time to time. In addition, under the terms of the sales agency financing agreement and master forward sale confirmation, Westar Energy may from time to time enter into one or more forward sale transactions with the bank, as forward purchaser, and the bank will borrow shares of Westar Energy's common stock from third parties and sell them through its agent. The agent receives a commission equal to 1% of the sales price of all shares sold under the agreements.

In April 2010, Westar Energy entered into a three-year sales agency financing agreement and master forward sale agreement with a bank that was terminated in March 2013. The maximum amount that Westar Energy could offer and sell under the agreements was the lesser of an aggregate of $500.0 million or approximately 22.0 million shares, subject to adjustment for share splits, share combinations and share dividends. Terms under these agreements are generally similar to the March 2013 agreements described above.

The following table summarizes our common stock activity pursuant to the three forward sale agreements.

Year Ended December 31,	2015	2014	2013
Shares that could be settled at beginning of year	9,160,500	12,052,976	1,753,415
Transactions entered	—	—	11,367,673
Transactions settled[(a)]	9,160,500	2,892,476	1,068,112
Shares that could be settled at end of year	—	9,160,500	12,052,976

[(a)] *The shares settled during the years ended December 31, 2015, 2014 and 2013, were settled with a physical settlement amount of approximately $254.6 million, $82.9 million and $27.0 million, respectively.*

The forward sale transactions were entered into at market prices; therefore, the forward sale agreements had no initial fair value. Westar Energy did not receive any proceeds from the sale of common stock under the forward sale agreements until transactions were settled. Westar Energy settled the forward sale transactions through physical share settlement and recorded the forward sale agreements within equity. The shares under the forward sale agreements were initially priced when the transactions were entered into and were subject to certain fixed pricing adjustments during the term of the agreements. The net proceeds from the forward sale transactions represent the prices established by the forward sale agreements applicable to the time periods in which physical settlement occurred.

Westar Energy used the proceeds from the transactions described above to repay short-term borrowings, with such borrowed amounts principally used for investments in capital equipment, as well as for working capital and general corporate purposes.

Summary of Cash Flows

Year Ended December 31,	2015	2014	2013
		(In Thousands)	
Cash flows from (used in):			
Operating activities	$ 714,543	$ 824,355	$ 702,803
Investing activities	(649,704)	(838,748)	(641,901)
Financing activities	(66,164)	14,462	(62,244)
Net (decrease) increase in cash and cash equivalents	$ (1,325)	$ 69	$ (1,342)

Cash Flows from Operating Activities

Cash flows from operating activities decreased $109.8 million in 2015 compared to 2014 due principally to our having received $62.8 million less for wholesale power sales and transmission services, our having received $51.8 million less from retail customers, our having paid $25.2 million more for the Wolf Creek refueling outage and our having received $10.0 million less for energy marketing activities. Partially offsetting these decreases was our having paid $40.1 million less for coal and natural gas.

Cash flows from operating activities increased $121.6 million in 2014 compared to 2013 due principally to our having received $384.2 million more from retail and wholesale customers. This increase was offset partially by our having paid $227.4 million more for fuel and purchased power.

Cash Flows used in Investing Activities

Cash flows used in investing activities decreased $189.0 million from 2015 to 2014 due primarily to our having invested $151.8 million less in additions to property, plant and equipment and our having received $23.6 million more from our investment in COLI.

Cash flows used in investing activities increased $196.8 million from 2013 to 2014 due primarily to decreased proceeds from investment in COLI of $104.4 million and increased investment in property, plant and equipment of $72.0 million.

Cash Flows from (used in) Financing Activities

Cash flows from financing activities decreased $80.6 million in 2015 compared to 2014. The decrease was due primarily to our having redeemed $208.4 million more in long-term debt, issuing $129.7 million less in commercial paper, and repaying $23.3 million more for borrowings against the cash surrender value of COLI. Partially offsetting these decreases was our having issued $170.3 million more in common stock and issuing $125.9 million more in long-term debt.

Cash flows from financing activities increased $76.7 million in 2014 compared to 2013. The increase was due primarily to our having borrowed $327.6 million more in short-term debt, our having repaid $104.2 million less for borrowings against the cash surrender value of COLI, and also an increase in issuances of common stock of $54.8 million. This was partially offset by our having paid $327.5 million more to retire, and our having received $74.4 million less from issuances, of long-term debt.

Future Cash Requirements

Our business requires significant capital investments. Through 2018, we expect to need cash primarily for utility construction programs designed to improve and expand facilities related to providing electric service, which include, but are not limited to, expenditures to develop renewable generation, new transmission lines and other improvements to our power plants, transmission and distribution lines and equipment. We expect to meet these cash needs with internally generated cash, short-term borrowings and the issuance of securities in the capital markets.

We have incurred and expect to continue to incur significant costs to comply with existing and future environmental laws and regulations, which are subject to changing interpretations and amendments. Changes to environmental regulations could result in significantly more stringent laws and regulations or interpretations thereof that could affect us and our industry in particular. These laws, regulations and interpretations could result in more stringent terms in our existing operating permits or a failure to obtain new permits could cause a material increase in our capital or operational costs and could otherwise have a material effect on our operations and consolidated financial results.

Capital expenditures for 2015 and anticipated capital expenditures, including costs of removal, for 2016 through 2018 are shown in the following table.

	Actual 2015	2016	Projected 2017	2018
		(In Thousands)		
Generation:				
Replacements and other	$ 162,367	$ 167,300	$ 178,700	$ 184,400
Environmental	94,620	39,200	17,600	24,000
Wind development	32,760	398,500	800	1,100
Nuclear fuel	15,644	22,600	45,800	25,500
Transmission	158,649	224,900	267,300	251,700
Distribution	182,011	216,300	208,500	192,600
Other	54,177	64,200	75,300	71,700
Total capital expenditures	$ 700,228	$1,133,000	$ 794,000	$ 751,000

We prepare these estimates for planning purposes and revise them from time to time. Actual expenditures will differ, perhaps materially, from our estimates due to changing regulatory requirements, changing costs, delays or advances in engineering, construction or permitting, changes in the availability and cost of capital and other factors discussed in "Item 1A. Risk Factors." We and our generating plant co-owners periodically evaluate these estimates and this may result in possibly material changes in actual costs.

We will also need significant amounts of cash in the future to meet our long-term debt obligations. The principal amounts of our long-term debt maturities as of December 31, 2015, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2016	$ —	$ 28,309
2017	125,000	26,842
2018	—	28,538
2019	300,000	31,485
2020	250,000	32,254
Thereafter	2,526,940	18,843
Total maturities	$ 3,201,940	$ 166,271

Pension Obligation

The amount we contribute to our pension plan for future periods is not yet known, however, in general we expect to fund our pension plan each year at least to a level equal to current year pension expense. We must also meet minimum funding requirements under the Employee Retirement Income Security Act, as amended by the Pension Protection Act. We may contribute additional amounts from time to time as deemed appropriate.

We contributed $41.0 million to our pension trust in 2015 and $26.4 million in 2014. We expect to contribute approximately $28.0 million in 2016. In 2015 and 2014, we also funded $5.8 million and $7.1 million, respectively, of Wolf Creek's pension plan contributions. In 2016, we plan to contribute $8.0 million to fund Wolf Creek's pension plan contributions. See Notes 11 and 12 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans" and "Wolf Creek Employee Benefit Plans," for additional discussion of Westar Energy and Wolf Creek benefit plans, respectively.

OFF-BALANCE SHEET ARRANGEMENTS

As discussed under "— Common Stock" above and in Note 16 of the Notes to Consolidated Financial Statements, "Common Stock," Westar Energy entered into several forward sale agreements with banks in 2013 which were fully settled in 2015. The forward sale agreements are off-balance sheet arrangements. We also have off-balance sheet arrangements in the form of operating leases and letters of credit entered into in the ordinary course of business. We did not have any additional off-balance sheet arrangements as of December 31, 2015.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

In the course of our business activities, we enter into a variety of contracts and commercial commitments. Some of these result in direct obligations reflected on our consolidated balance sheets while others are commitments, some firm and some based on uncertainties, not reflected in our underlying consolidated financial statements.

Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2015.

	Total	2016	2017-2018	2019-2020	Thereafter
		(In Thousands)			
Long-term debt[a]	$ 3,201,940	$ —	$ 125,000	$ 550,000	$ 2,526,940
Long-term debt of VIEs[a]	166,271	28,309	55,380	63,739	18,843
Interest on long-term debt[b]	2,790,205	146,384	283,113	249,744	2,110,964
Interest on long-term debt of VIEs	27,595	8,697	12,594	5,772	532
Long-term debt, including interest	6,186,011	183,390	476,087	869,255	4,657,279
Pension and post-retirement benefit expected contributions[c]	36,600	36,600	—	—	—
Capital leases[d]	81,133	5,812	10,619	8,652	56,050
Operating leases[e]	59,132	13,550	21,862	14,803	8,917
Other obligations of VIEs[f]	12,866	2,550	10,316	—	—
Fossil fuel[g]	947,522	195,654	358,930	336,560	56,378
Nuclear fuel[h]	113,705	17,895	40,114	36,547	19,149
Transmission service[i]	7,114	7,114	—	—	—
Wind development obligations	259,491	259,491	—	—	—
Unconditional purchase obligations	591,422	497,759	61,943	31,720	—
Total contractual obligations[j]	$ 8,294,996	$1,219,815	$ 979,871	$1,297,537	$ 4,797,773

[a] *See Note 9 of the Notes to Consolidated Financial Statements, "Long-Term Debt," for individual maturities.*

[b] *We calculate interest on our variable rate debt based on the effective interest rates as of December 31, 2015.*

[c] *Our contribution amounts for future periods are not yet known. See Notes 11 and 12 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans" and "Wolf Creek Employee Benefit Plans," for additional information regarding pension and post-retirement benefits.*

[d] *Includes principal and interest on capital leases.*

[e] *Includes leases for operating facilities, operating equipment, office space, office equipment, vehicles and rail cars as well as other miscellaneous commitments.*

[f] *See Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," for additional information on VIEs.*

[g] *Coal and natural gas commodity and transportation contracts.*

[h] *Uranium concentrates, conversion, enrichment and fabrication.*

[i] *Includes obligations to SPP for transmission service payments. See Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies — Fuel, Purchase Power and Transmission Commitments" for additional information.*

[j] *We have $1.5 million of unrecognized income tax benefits, including interest, that are not included in this table because we cannot reasonably estimate the timing of the cash payments to taxing authorities assuming those unrecognized income tax benefits are settled at the amounts accrued as of December 31, 2015.*

Commercial Commitments

Our commercial commitments as of December 31, 2015, consist of outstanding letters of credit that expire in 2016, some of which automatically renew annually. The letters of credit are comprised of $13.7 million related to transmission projects, $3.9 million related to energy marketing and trading activities, $0.9 million related to workers' compensation and $1.5 million related to other operating activities for a total outstanding balance of $20.0 million.

OTHER INFORMATION

Changes in Prices

See Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," for information on our prices.

Wolf Creek Outage

Wolf Creek normally operates on an 18-month planned refueling and maintenance outage schedule. As authorized by our regulators, incremental maintenance costs of planned refueling and maintenance outages are deferred and amortized ratably over the period between planned refueling and maintenance outages. In early 2015, Wolf Creek underwent a planned refueling and maintenance outage. Our share of the outage costs was approximately $31.9 million. The next refueling and maintenance outage is planned for the fall of 2016.

Stock-Based Compensation

We use two types of RSUs for our stock-based compensation awards; those with service requirements and those with performance measures. See Note 11 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans," for additional information. Total unrecognized compensation cost related to RSU awards with only service requirements was $4.5 million as of December 31, 2015, and we expect to recognize these costs over a remaining weighted-average period of 1.7 years. Total unrecognized compensation cost related to RSU awards with performance measures was $4.0 million as of December 31, 2015, and we expect to recognize these costs over a remaining weighted-average period of 1.7 years.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our fuel procurement and energy marketing activities involve primary market risk exposures, including commodity price risk, credit risk and interest rate risk. Commodity price risk is the potential adverse price impact related to the purchase or sale of electricity and energy-related products. Credit risk is the potential adverse financial impact resulting from non-performance by a counterparty of its contractual obligations. Interest rate risk is the potential adverse financial impact related to changes in interest rates. In addition, our investments in trusts to fund nuclear plant decommissioning and to fund non-qualified retirement benefits give rise to security price risk. Many of the securities in these trusts are exposed to price fluctuations in the capital markets.

Commodity Price Risk

We engage in both financial and physical trading with the goal of managing our commodity price risk, enhancing system reliability and increasing profits. We procure and trade electricity, coal, natural gas and other energy-related products by utilizing energy commodity contracts and a variety of financial instruments, including futures contracts, options and swaps.

We use various types of fuel, including coal, natural gas, uranium and diesel to operate our plants and also purchase power to meet customer demand. Our prices and consolidated financial results are exposed to market risks from commodity price changes for electricity and other energy-related products as well as from interest rates. Volatility in these markets impacts our costs of purchased power, costs of fuel for our generating plants and our participation in energy markets. We strive to manage our customers' and our exposure to these market risks through regulatory, operating and financing activities and, when we deem appropriate, we economically hedge a portion of these risks through the use of derivative financial instruments for non-trading purposes.

Factors that affect our commodity price exposure are the quantity and availability of fuel used for generation, the availability of our power plants and the quantity of electricity customers consume. Quantities of fossil fuel we use to generate electricity fluctuate from period to period based on availability, price and deliverability of a given fuel type, as well as planned and unscheduled outages at our generating plants that use fossil fuels. Our commodity price exposure is also affected by our nuclear plant refueling and maintenance schedule. Our customers' electricity usage also varies based on weather, the economy and other factors.

We trade various types of fuel primarily to reduce exposure related to the volatility of commodity prices. A significant portion of our coal requirements is purchased under long-term contracts to hedge much of the fuel exposure for customers. If we were unable to generate an adequate supply of electricity for our customers, we would purchase power in the wholesale market to the extent it is available, subject to possible transmission constraints, and/or implement curtailment or interruption procedures as permitted in our tariffs and terms and conditions of service.

One way by which we manage and measure the commodity price risk of our trading portfolio is by using a variance/covariance value-at-risk (VaR) model. In addition to VaR, we employ additional risk control processes such as stress testing, daily loss limits, credit limits and position limits. We expect to use similar control processes in the future. The use of VaR requires assumptions, including the selection of a confidence level and a measure of volatility associated with potential losses and the estimated holding period. We express VaR as a potential dollar loss based on a 95% confidence level using a one-day holding period and a 20-day historical observation period. It is possible that actual results may differ significantly from assumptions. Accordingly, VaR may not accurately reflect our levels of exposure. The energy trading and market-based wholesale portfolio VaR amounts for 2015 and 2014 were as follows:

	2015	2014
	(In Thousands)	
High	$ 514	$ 614
Low	56	14
Average	199	76

Interest Rate Risk

We have entered into numerous fixed and variable rate debt obligations. For details, see Note 9 of the Notes to Consolidated Financial Statements, "Long-Term Debt." We manage our interest rate risk related to these debt obligations by limiting our exposure to variable interest rate debt, diversifying maturity dates and entering into treasury yield hedge transactions. We may also use other financial derivative instruments such as interest rate swaps. We compute and present information about the sensitivity to changes in interest rates for variable rate debt and current maturities of fixed rate debt by assuming a 100 basis point change in the current interest rates applicable to such debt over the remaining time the debt is outstanding.

We had approximately $400.5 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2015. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $3.9 million. As of December 31, 2015, we had $121.9 million of variable rate bonds insured by bond insurers. Interest rates payable under these bonds are normally set through periodic auctions. However, conditions in the credit markets over the past few years caused a dramatic reduction in the demand for auction bonds, which led to failed auctions. The contractual provisions of these securities set forth an indexing formula method by which interest will be paid in the event of an auction failure. Depending on the level of these reference indices, our interest costs may be higher or lower than what they would have been had the securities been auctioned successfully. Additionally, should insurers of those bonds experience a decrease in their credit ratings, such event could increase our borrowing costs. Furthermore, a decline in interest rates generally can serve to increase our pension and post-retirement benefit obligations.

Security Price Risk

We maintain the NDT, as required by the NRC and Kansas statute, to fund certain costs of nuclear plant decommissioning. As of December 31, 2015, investments in the NDT were allocated 50% to equity securities, 29% to debt securities, 6% to combination debt/equity/other securities, 9% to alternative investments, 6% to real estate securities and less than 1% to cash equivalents. As of December 31, 2015 and 2014, the fair value of the NDT investments was $184.1 million and $185.0 million, respectively. Changes in interest rates and/or other market changes resulting in a 10% decrease in the value of the securities would have resulted in an $18.4 million decrease in the value of the NDT as of December 31, 2015.

We also maintain a trust to fund non-qualified retirement benefits. As of December 31, 2015, investments in the trust were comprised of 66% equity securities, 34% debt securities and less than 1% cash equivalents. The fair value of the investments in this trust was $33.9 million as of December 31, 2015, and $35.5 million as of December 31, 2014. Changes in interest rates and/or other market changes resulting in a 10% decrease in the value of the securities would have resulted in a $3.4 million decrease in the value of the trust as of December 31, 2015.

By maintaining diversified portfolios of securities, we seek to optimize the returns to fund the aforementioned obligations within acceptable risk tolerances, including interest rate risk. However, many of the securities in the portfolios are exposed to price fluctuations in the capital markets. If the value of the securities diminishes, the cost of funding the obligations rises. We actively monitor the portfolios by benchmarking the performance of the investments against relevant indices and by maintaining and periodically reviewing the asset allocations in relation to established policy targets. Our exposure to security price risk related to the NDT is in part mitigated because we are currently allowed to recover decommissioning costs in the prices we charge our customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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SCHEDULES OMITTED

The following schedules are omitted because of the absence of the conditions under which they are required or the information is included in our consolidated financial statements and schedules presented:

I, III, IV and V.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We are responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles (GAAP) and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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.

We assessed the effectiveness of our internal control over financial reporting as of December 31, 2015. In making this assessment, we used the criteria set forth in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, we concluded that, as of December 31, 2015, our internal control over financial reporting is effective based on those criteria. Our independent registered public accounting firm has issued an audit report on the company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Westar Energy, Inc.
Topeka, Kansas

We have audited the internal control over financial reporting of Westar Energy, Inc. and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management's report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule of the Company as of and for the year ended December 31, 2015 of the Company and our report dated February 24, 2016 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 24, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Westar Energy, Inc.
Topeka, Kansas

We have audited the accompanying consolidated balance sheets of Westar Energy, Inc. and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Westar Energy, Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 24, 2016

WESTAR ENERGY, INC. CONSOLIDATED BALANCE SHEETS

As of December 31,	2015	2014
(Dollars in Thousands, Except Par Values)		
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,231	$ 4,556
Accounts receivable, net of allowance for doubtful accounts of $5,294 and $5,309, respectively	258,286	267,327
Fuel inventory and supplies	301,294	247,406
Prepaid expenses	16,864	15,793
Regulatory assets	109,606	105,549
Other	27,860	28,772
Total Current Assets	717,141	669,403
PROPERTY, PLANT AND EQUIPMENT, NET	8,524,902	8,162,908
PROPERTY, PLANT AND EQUIPMENT OF VARIABLE INTEREST ENTITIES, NET	268,239	278,573
OTHER ASSETS:		
Regulatory assets	751,312	754,229
Nuclear decommissioning trust	184,057	185,016
Other	260,015	238,777
Total Other Assets	1,195,384	1,178,022
TOTAL ASSETS	$10,705,666	$10,288,906
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt of variable interest entities	$ 28,309	$ 27,933
Short-term debt	250,300	257,600
Accounts payable	220,969	219,351
Accrued dividends	49,829	44,971
Accrued taxes	83,773	74,356
Accrued interest	71,426	79,707
Regulatory liabilities	25,697	55,142
Other	106,632	90,571
Total Current Liabilities	836,935	849,631
LONG-TERM LIABILITIES:		
Long-term debt, net	3,163,950	3,187,080
Long-term debt of variable interest entities, net	138,097	166,565
Deferred income taxes	1,591,430	1,445,851
Unamortized investment tax credits	209,763	211,040
Regulatory liabilities	267,114	288,343
Accrued employee benefits	462,304	532,622
Asset retirement obligations	275,285	230,668
Other	88,825	75,799
Total Long-Term Liabilities	6,196,768	6,137,968
COMMITMENTS AND CONTINGENCIES (SEE NOTES 3, 13 AND 15)		
EQUITY:		
Westar Energy, Inc. Shareholders' Equity:		
Common stock, par value $5 per share; authorized 275,000,000 shares; issued and outstanding 141,353,426 shares and 131,687,454 shares, respective to each date	706,767	658,437
Paid-in capital	2,004,124	1,781,120
Retained earnings	945,830	855,299
Total Westar Energy, Inc. Shareholders' Equity	3,656,721	3,294,856
Noncontrolling Interests	15,242	6,451
Total Equity	3,671,963	3,301,307
TOTAL LIABILITIES AND EQUITY	$10,705,666	$10,288,906

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31,	2015	2014	2013
(Dollars in Thousands, Except Per Share Amounts)			
REVENUES	$ 2,459,164	$ 2,601,703	$ 2,370,654
OPERATING EXPENSES:			
Fuel and purchased power	561,065	705,450	634,797
SPP network transmission costs	229,043	218,924	178,604
Operating and maintenance	330,289	367,188	359,060
Depreciation and amortization	310,591	286,442	272,593
Selling, general and administrative	250,278	250,439	224,133
Taxes other than income tax	156,901	140,302	122,282
Total Operating Expenses	1,838,167	1,968,745	1,791,469
INCOME FROM OPERATIONS	620,997	632,958	579,185
OTHER INCOME (EXPENSE):			
Investment earnings	7,799	10,622	10,056
Other income	19,438	31,522	35,609
Other expense	(17,636)	(18,389)	(18,099)
Total Other Income	9,601	23,755	27,566
Interest expense	176,802	183,118	182,167
INCOME BEFORE INCOME TAXES	453,796	473,595	424,584
Income tax expense	152,000	151,270	123,721
NET INCOME	301,796	322,325	300,863
Less: Net income attributable to noncontrolling interests	9,867	9,066	8,343
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 291,929	$ 313,259	$ 292,520
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY (SEE NOTE 2):			
Basic earnings per common share	$ 2.11	$ 2.40	$ 2.29
Diluted earnings per common share	$ 2.09	$ 2.35	$ 2.27
AVERAGE EQUIVALENT COMMON SHARES OUTSTANDING	137,957,515	130,014,941	127,462,994
DIVIDENDS DECLARED PER COMMON SHARE	$ 1.44	$ 1.40	$ 1.36

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31,	2015	2014	2013
(Dollars in Thousands)			
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	**$ 301,796**	$ 322,325	$ 300,863
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**310,591**	286,442	272,593
Amortization of nuclear fuel	**26,974**	26,051	22,690
Amortization of deferred regulatory gain from sale leaseback	**(5,495)**	(5,495)	(5,495)
Amortization of corporate-owned life insurance	**19,850**	20,202	15,149
Non-cash compensation	**8,345**	7,280	8,188
Net deferred income taxes and credits	**151,332**	151,451	123,307
Stock-based compensation excess tax benefits	**(1,307)**	(875)	(576)
Allowance for equity funds used during construction	**(2,075)**	(17,029)	(14,143)
Changes in working capital items:			
Accounts receivable	**9,042**	(17,291)	(24,649)
Fuel inventory and supplies	**(53,263)**	(8,773)	10,124
Prepaid expenses and other	**(23,145)**	36,717	(12,316)
Accounts payable	**6,636**	6,189	7,856
Accrued taxes	**13,073**	6,596	14,218
Other current liabilities	**(80,396)**	(31,624)	(52,829)
Changes in other assets	**2,199**	6,378	(4,167)
Changes in other liabilities	**30,386**	35,811	41,990
Cash Flows from Operating Activities	**714,543**	824,355	702,803
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	**(700,228)**	(852,052)	(780,098)
Purchase of securities - trusts	**(37,557)**	(9,075)	(66,668)
Sale of securities - trusts	**37,930**	11,125	81,994
Investment in corporate-owned life insurance	**(14,845)**	(16,250)	(17,724)
Proceeds from investment in corporate-owned life insurance	**66,794**	43,234	147,658
Proceeds from federal grant	**—**	—	876
Investment in affiliated company	**(575)**	(8,000)	(4,947)
Other investing activities	**(1,223)**	(7,730)	(2,992)
Cash Flows used in Investing Activities	**(649,704)**	(838,748)	(641,901)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	**(7,300)**	122,406	(205,241)
Proceeds from long-term debt	**543,881**	417,943	492,347
Retirements of long-term debt	**(635,891)**	(427,500)	(100,000)
Retirements of long-term debt of variable interest entities	**(27,933)**	(27,479)	(25,942)
Repayment of capital leases	**(2,591)**	(3,340)	(2,995)
Borrowings against cash surrender value of corporate-owned life insurance	**59,431**	59,766	59,565
Repayment of borrowings against cash surrender value of corporate-owned life insurance	**(64,593)**	(41,249)	(145,418)
Stock-based compensation excess tax benefits	**1,307**	875	576
Issuance of common stock	**257,998**	87,669	32,906
Distributions to shareholders of noncontrolling interests	**(1,076)**	(1,030)	(2,419)
Cash dividends paid	**(186,120)**	(171,507)	(162,904)
Other financing activities	**(3,277)**	(2,092)	(2,719)
Cash Flows (used in) from Financing Activities	**(66,164)**	14,462	(62,244)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**(1,325)**	69	(1,342)
CASH AND CASH EQUIVALENTS:			
Beginning of period	**4,556**	4,487	5,829
End of period	**$ 3,231**	$ 4,556	$ 4,487

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Westar Energy, Inc. Shareholders					
	Common stock shares	Common stock	Paid-in capital	Retained earnings	Non-controlling interests	Total equity
			(Dollars in Thousands)			
Balance as of December 31, 2012	126,503,748	$ 632,519	$ 1,656,972	$ 606,649	$ 14,115	$ 2,910,255
Net income	—	—	—	292,520	8,343	300,863
Issuance of stock	1,256,391	6,282	26,624	—	—	32,906
Issuance of stock for compensation and reinvested dividends	494,090	2,470	7,171	—	—	9,641
Tax withholding related to stock compensation	—	—	(2,719)	—	—	(2,719)
Dividends declared on common stock ($1.36 per share)	—	—	—	(174,393)	—	(174,393)
Stock compensation expense	—	—	8,103	—	—	8,103
Tax benefit on stock compensation	—	—	576	—	—	576
Deconsolidation of noncontrolling interests	—	—	—	—	(14,282)	(14,282)
Distributions to shareholders of noncontrolling interests	—	—	—	—	(2,419)	(2,419)
Balance as of December 31, 2013	128,254,229	641,271	1,696,727	724,776	5,757	3,068,531
Net income	—	—	—	313,259	9,066	322,325
Issuance of stock	3,026,239	15,131	72,538	—	—	87,669
Issuance of stock for compensation and reinvested dividends	406,986	2,035	7,120	—	—	9,155
Tax withholding related to stock compensation	—	—	(2,092)	—	—	(2,092)
Dividends declared on common stock ($1.40 per share)	—	—	—	(182,736)	—	(182,736)
Stock compensation expense	—	—	7,193	—	—	7,193
Tax benefit on stock compensation	—	—	875	—	—	875
Deconsolidation of noncontrolling interests	—	—	—	—	(7,342)	(7,342)
Distributions to shareholders of noncontrolling interests	—	—	—	—	(1,030)	(1,030)
Other	—	—	(1,241)	—	—	(1,241)
Balance as of December 31, 2014	131,687,454	658,437	1,781,120	855,299	6,451	3,301,307
Net income	—	—	—	291,929	9,867	301,796
Issuance of stock	9,249,986	46,250	211,748	—	—	257,998
Issuance of stock for compensation and reinvested dividends	415,986	2,080	8,373	—	—	10,453
Tax withholding related to stock compensation	—	—	(3,277)	—	—	(3,277)
Dividends declared on common stock ($1.44 per share)	—	—	—	(201,398)	—	(201,398)
Stock compensation expense	—	—	8,250	—	—	8,250
Tax benefit on stock compensation	—	—	1,307	—	—	1,307
Distributions to shareholders of noncontrolling interests	—	—	—	—	(1,076)	(1,076)
Other	—	—	(3,397)	—	—	(3,397)
Balance as of December 31, 2015	**141,353,426**	**$ 706,767**	**$ 2,004,124**	**$ 945,830**	**$ 15,242**	**$ 3,671,963**

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

We are the largest electric utility in Kansas. Unless the context otherwise indicates, all references in this Annual Report on Form 10-K to "the company," "we," "us," "our" and similar words are to Westar Energy, Inc. and its consolidated subsidiaries. The term "Westar Energy" refers to Westar Energy, Inc., a Kansas corporation incorporated in 1924, alone and not together with its consolidated subsidiaries.

We provide electric generation, transmission and distribution services to approximately 700,000 customers in Kansas. Westar Energy provides these services in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric Company (KGE), Westar Energy's wholly-owned subsidiary, provides these services in south-central and southeastern Kansas, including the city of Wichita. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

We prepare our consolidated financial statements in accordance with generally accepted accounting principles (GAAP) for the United States of America. Our consolidated financial statements include all operating divisions, majority owned subsidiaries and variable interest entities (VIEs) of which we maintain a controlling interest or are the primary beneficiary reported as a single reportable segment. Undivided interests in jointly-owned generation facilities are included on a proportionate basis. Intercompany accounts and transactions have been eliminated in consolidation.

Use of Management's Estimates

When we prepare our consolidated financial statements, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities, at the date of our consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an ongoing basis, including those related to depreciation, unbilled revenue, valuation of investments, forecasted fuel costs included in our retail energy cost adjustment billed to customers, income taxes, pension and post-retirement benefits, our asset retirement obligations (AROs) including the decommissioning of Wolf Creek Generating Station (Wolf Creek), environmental issues, VIEs, contingencies and litigation. Actual results may differ from those estimates under different assumptions or conditions.

Regulatory Accounting

We apply accounting standards that recognize the economic effects of rate regulation. Accordingly, we have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent. See Note 3, "Rate Matters and Regulation," for additional information regarding our regulatory assets and liabilities.

Cash and Cash Equivalents

We consider investments that are highly liquid and have maturities of three months or less when purchased to be cash equivalents.

Fuel Inventory and Supplies

We state fuel inventory and supplies at average cost. Following are the balances for fuel inventory and supplies stated separately.

As of December 31,	2015	2014
	(In Thousands)	
Fuel inventory	$ 113,438	$ 70,416
Supplies	187,856	176,990
Fuel inventory and supplies	$ 301,294	$ 247,406

Property, Plant and Equipment

We record the value of property, plant and equipment, including that of VIEs, at cost. For plant, cost includes contracted services, direct labor and materials, indirect charges for engineering and supervision and an allowance for funds used during construction (AFUDC). AFUDC represents the allowed cost of capital used to finance utility construction activity. We compute AFUDC by applying a composite rate to qualified construction work in progress. We credit other income (for equity funds) and interest expense (for borrowed funds) for the amount of AFUDC capitalized as construction cost on the accompanying consolidated statements of income as follows:

Year Ended December 31,	2015	2014	2013
	(Dollars In Thousands)		
Borrowed funds	$ 3,505	$ 12,044	$ 11,706
Equity funds	2,075	17,029	14,143
Total	$ 5,580	$ 29,073	$ 25,849
Average AFUDC Rates	2.7%	6.7%	4.8%

We charge maintenance costs and replacements of minor items of property to expense as incurred, except for maintenance costs incurred for our planned refueling and maintenance outages at Wolf Creek. As authorized by regulators, we defer and amortize to expense ratably over the period between planned outages incremental maintenance costs incurred for such outages. When a unit of depreciable property is retired, we charge to accumulated depreciation the original cost less salvage value.

Depreciation

We depreciate utility plant using a straight-line method. The depreciation rates are based on an average annual composite basis using group rates that approximated 2.5% in 2015, 2.4% in 2014 and 2.5% in 2013.

Depreciable lives of property, plant and equipment are as follows.

	Years
Fossil fuel generating facilities	6 to 78
Nuclear fuel generating facility	55 to 71
Wind generating facilities	19 to 20
Transmission facilities	15 to 75
Distribution facilities	22 to 68
Other	5 to 30

Nuclear Fuel

We record as property, plant and equipment our share of the cost of nuclear fuel used in the process of refinement, conversion, enrichment and fabrication. We reflect this at original cost and amortize such amounts to fuel expense based on the quantity of heat consumed during the generation of electricity as measured in millions of British thermal units (MMBtu). The accumulated amortization of nuclear fuel in the reactor was $59.1 million as of December 31, 2015, and $72.3 million as of December 31, 2014. The cost of nuclear fuel charged to fuel and purchased power expense was $27.3 million in 2015, $27.3 million in 2014 and $26.5 million in 2013.

Cash Surrender Value of Life Insurance

We recorded on our consolidated balance sheets in other long-term assets the following amounts related to corporate-owned life insurance (COLI) policies.

As of December 31,	2015	2014
	(In Thousands)	
Cash surrender value of policies	$ 1,299,408	$ 1,306,777
Borrowings against policies	(1,168,794)	(1,173,956)
Corporate-owned life insurance, net	$ 130,614	$ 132,821

We record as income increases in cash surrender value and death benefits. We offset against policy income the interest expense that we incur on policy loans. Income from death benefits is highly variable from period to period.

Revenue Recognition

We record revenue at the time we deliver electricity to customers. We determine the amounts delivered to individual customers through systematic monthly readings of customer meters. At the end of each month, we estimate how much electricity we have delivered since the prior meter reading and record the corresponding unbilled revenue.

Our unbilled revenue estimate is affected by factors including fluctuations in energy demand, weather, line losses and changes in the composition of customer classes. We recorded estimated unbilled revenue of $66.0 million as of December 31, 2015, and $61.0 million as of December 31, 2014.

Allowance for Doubtful Accounts

We determine our allowance for doubtful accounts based on the age of our receivables. We charge receivables off when they are deemed uncollectible, which is based on a number of factors including specific facts surrounding an account and management's judgment.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under this method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over the lives of the related properties as required by tax laws and regulatory practices. We recognize production tax credits in the year that electricity is generated to the extent that realization of such benefits is more likely than not.

We record deferred tax assets to the extent capital losses, operating losses or tax credits will be carried forward to future periods. However, when we believe based on available evidence that we do not, or will not, have sufficient future capital gains or taxable income in the appropriate taxing jurisdiction to realize the entire benefit during the applicable carryforward period, we record a valuation allowance against the deferred tax asset.

The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Accordingly, we must make judgments regarding income tax exposure. Interpretations of and guidance surrounding income tax laws and regulations change over time. As a result, changes in our judgments can materially affect amounts we recognize in our consolidated financial statements. See Note 10, "Taxes," for additional detail on our accounting for income taxes.

Sales Tax

We account for the collection and remittance of sales tax on a net basis. As a result, we do not reflect sales tax in our consolidated statements of income.

Earnings Per Share

We have participating securities in the form of unvested restricted share units (RSUs) with nonforfeitable rights to dividend equivalents that receive dividends on an equal basis with dividends declared on common shares. As a result, we apply the two-class method of computing basic and diluted earnings per share (EPS).

To compute basic EPS, we divide the earnings allocated to common stock by the weighted average number of common shares outstanding. Diluted EPS includes the effect of issuable common shares resulting from our forward sale agreements, if any, and RSUs with forfeitable rights to dividend equivalents. We compute the dilutive effect of potential issuances of common shares using the treasury stock method.

The following table reconciles our basic and diluted EPS from net income.

Year Ended December 31,	2015	2014	2013
	(Dollars In Thousands, Except Per Share Amounts)		
Net income	$ 301,796	$ 322,325	$ 300,863
Less: Net income attributable to noncontrolling interests	9,867	9,066	8,343
Net income attributable to Westar Energy, Inc.	291,929	313,259	292,520
Less: Net income allocated to RSUs	646	790	810
Net income allocated to common stock	$ 291,283	$ 312,469	$ 291,710
Weighted average equivalent common shares outstanding – basic	137,957,515	130,014,941	127,462,994
Effect of dilutive securities:			
RSUs	299,198	181,397	17,195
Forward sale agreements	1,021,510	2,628,187	818,505
Weighted average equivalent common shares outstanding – diluted[(a)]	139,278,223	132,824,525	128,298,694
Earnings per common share, basic	$ 2.11	$ 2.40	$ 2.29
Earnings per common share, diluted	$ 2.09	$ 2.35	$ 2.27

[(a)] *For the years ended December 31, 2015, 2014 and 2013, we had no antidilutive securities.*

Supplemental Cash Flow Information

Year Ended December 31,	2015	2014	2013
		(In Thousands)	
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$ 161,484	$ 160,292	$ 148,691
Interest on financing activities of VIEs	10,430	12,183	13,892
Income taxes, net of refunds	(410)	458	(11)
NON-CASH INVESTING TRANSACTIONS:			
Property, plant and equipment additions	105,169	143,192	127,544
Property, plant and equipment of VIEs	—	(7,342)	(14,282)
NON-CASH FINANCING TRANSACTIONS:			
Issuance of stock for compensation and reinvested dividends	10,453	9,155	9,641
Deconsolidation of VIEs	—	(7,342)	(14,282)
Assets acquired through capital leases	3,130	8,717	334

New Accounting Pronouncements

We prepare our consolidated financial statements in accordance with GAAP for the United States of America. To address current issues in accounting, the Financial Accounting Standards Board (FASB) issued the following new accounting pronouncements which may affect our accounting and/or disclosure.

Presentation of Financial Statements

In November 2015, the FASB issued Accounting Standard Update (ASU) No. 2015-17 to simplify the presentation of deferred income taxes. This guidance requires that deferred tax liabilities and assets be classified as long-term in a classified statement of position. The guidance is effective for fiscal years beginning after December 15, 2016, with early adoption permitted. We have elected to retrospectively adopt effective December 31, 2015, resulting in reducing long-term deferred income tax liabilities as of December 31, 2014, by $29.6 million previously presented as current deferred tax assets.

In April 2015, the FASB issued ASU No. 2015-03 to simplify the presentation of debt issuance costs. This guidance requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The guidance is effective for fiscal years beginning after December 15, 2015, with early adoption permitted. We have elected to adopt effective December 31, 2015, resulting in reducing long-term debt as of December 31, 2014, by $1.9 million previously presented in other current assets and $26.6 million previously presented in other long-term assets.

Extraordinary and Unusual Items

In January 2015, the FASB issued ASU No. 2015-01, which eliminates the accounting concept of extraordinary items. The objective of the new guidance is to reduce complexity in accounting standards while maintaining or improving the usefulness of information provided. The guidance is effective for fiscal years beginning after December 15, 2015, with early adoption permitted. We elected to adopt effective January 1, 2015, without an impact to our financial statements.

Revenue Recognition

In May 2014, the FASB issued ASU No. 2014-09, which addresses revenue from contracts with customers. The objective of the new guidance is to establish principles to report useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue from contracts with customers. This guidance was effective for fiscal years beginning after December 15, 2016. However, in August 2015, the FASB deferred the effective date by one year. Early application of the standard is permitted for fiscal years beginning after December 15, 2016. The standard permits the use of either the retrospective application or cumulative effect transition method. We have not yet selected a transition method or determined the impact on our consolidated financial statements but we do not expect it to be material.

3. RATE MATTERS AND REGULATION

Regulatory Assets and Regulatory Liabilities

Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer prices. Regulatory liabilities represent probable future reductions in revenue or refunds to customers through the price setting process. Regulatory assets and liabilities reflected on our consolidated balance sheets are as follows.

As of December 31,	2015	2014
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$ 353,785	$ 435,590
Amounts due from customers for future income taxes, net	144,120	153,984
Debt reacquisition costs	121,631	61,079
Depreciation	65,797	68,422
Ad valorem tax	44,455	39,428
Asset retirement obligations	31,996	26,106
Treasury yield hedges	25,634	26,614
Wolf Creek outage	16,561	11,165
Disallowed plant costs	15,639	15,809
La Cygne environmental costs	15,446	—
Energy efficiency program costs	7,922	8,933
Other regulatory assets	17,932	12,648
Total regulatory assets	$ 860,918	$ 859,778
Regulatory Liabilities:		
Deferred regulatory gain from sale leaseback	$ 75,560	$ 81,055
Removal costs	53,834	88,242
Jurisdictional allowance for funds used during construction	32,673	33,103
Pension and other post-retirement benefits costs	32,181	15,473
Nuclear decommissioning	30,659	43,641
La Cygne leasehold dismantling costs	25,330	22,918
Kansas tax credits	12,857	12,725
Retail energy cost adjustment	12,686	33,274
Purchase power agreement	9,972	4,377
Other regulatory liabilities	7,059	8,677
Total regulatory liabilities	$ 292,811	$ 343,485

Below we summarize the nature and period of recovery for each of the regulatory assets listed in the table above.

- **Deferred employee benefit costs:** Includes $319.7 million for pension and post-retirement benefit obligations and $34.1 million for actual pension expense in excess of the amount of such expense recognized in setting our prices. The decrease from 2014 to 2015 is attributable primarily to an increase in the discount rates used to calculate our and Wolf Creek's pension benefit obligations and the adoption of updated mortality tables. During 2016, we will amortize to expense approximately $26.0 million of the benefit obligations and approximately $6.8 million of the excess pension expense. We are amortizing the excess pension expense over a five-year period. We do not earn a return on this asset.
- **Amounts due from customers for future income taxes, net:** In accordance with various orders, we have reduced our prices to reflect the income tax benefits associated with certain income tax deductions, thereby passing on these benefits to customers at the time we receive them. We believe it is probable that the net future increases in income taxes payable will be recovered from customers

when these temporary income tax benefits reverse in future periods. We have recorded a regulatory asset, net of the regulatory liability, for these amounts. We also have recorded a regulatory liability for our obligation to customers for income taxes recovered in earlier periods when corporate income tax rates were higher than current income tax rates. This benefit will be returned to customers as these temporary differences reverse in future periods. The income tax-related regulatory assets and liabilities as well as unamortized investment tax credits are also temporary differences for which deferred income taxes have been provided. These items are measured by the expected cash flows to be received or settled in future prices. We do not earn a return on this net asset.

- **Debt reacquisition costs:** Includes costs incurred to reacquire and refinance debt. These costs are amortized over the term of the new debt. We do not earn a return on this asset.
- **Depreciation:** Represents the difference between regulatory depreciation expense and depreciation expense we record for financial reporting purposes. We earn a return on this asset and amortize the difference over the life of the related plant.
- **Ad valorem tax:** Represents actual costs incurred for property taxes in excess of amounts collected in our prices. We expect to recover these amounts in our prices over a one-year period. We do not earn a return on this asset.
- **Asset retirement obligations:** Represents amounts associated with our AROs as discussed in Note 14, "Asset Retirement Obligations." We recover these amounts over the life of the related plant. We do not earn a return on this asset.
- **Treasury yield hedges:** Represents the effective portion of treasury yield hedge transactions. This amount will be amortized to interest expense over the term of the related debt. We do not earn a return on this asset.
- **Wolf Creek outage:** We defer the expenses associated with Wolf Creek's scheduled refueling and maintenance outages and amortize these expenses during the period between planned outages. We do not earn a return on this asset.
- **Disallowed plant costs:** Originally there was a decision to disallow certain costs related to the Wolf Creek plant. Subsequently, in 1987, the Kansas Corporation Commission (KCC) revised its original conclusion and provided for recovery of an indirect disallowance with no return on investment. This regulatory asset represents the present value of the future expected revenues to be provided to recover these costs, net of the amounts amortized.
- **La Cygne environmental costs:** Represents the deferral of depreciation and amortization expense and associated carrying charges related to the La Cygne Generating Station (La Cygne) environmental project from the in-service date until late October 2015, the effective date of our state general rate review. This amount will be amortized over the life of the related asset. We earn a return on this asset.
- **Energy efficiency program costs:** We accumulate and defer for future recovery costs related to our various energy efficiency programs. We will amortize such costs over a one-year period. We do not earn a return on this asset.
- **Other regulatory assets:** Includes various regulatory assets that individually are small in relation to the total regulatory asset balance. Other regulatory assets have various recovery periods. We do not earn a return on any of these assets.

Below we summarize the nature and period of amortization for each of the regulatory liabilities listed in the table above.

- **Deferred regulatory gain from sale leaseback:** Represents the gain KGE recorded on the 1987 sale and leaseback of its 50% interest in La Cygne unit 2. We amortize the gain over the lease term.
- **Removal costs:** Represents amounts collected, but not yet spent, to dispose of plant assets that do not represent legal retirement obligations. This liability will be discharged as removal costs are incurred.
- **Jurisdictional allowance for funds used during construction:** This item represents AFUDC that is accrued subsequent to the time the associated construction charges are included in our rates and prior to the time the related assets are placed in service. The AFUDC is amortized to depreciation expense over the useful life of the asset that is placed in service.
- **Pension and other post-retirement benefits costs:** Represents amount of pension and other post-retirement benefits expense recognized in setting our prices in excess of actual pension and other post-retirement benefits expense. We amortize the amount over a five-year period.
- **Nuclear decommissioning:** We have a legal obligation to decommission Wolf Creek at the end of its useful life. This amount represents the difference between the fair value of the assets held in a decommissioning trust and the amount recorded for the accumulated accretion and depreciation expense associated with our ARO. See Notes 4, 5 and 14, "Financial Instruments and Trading Securities," "Financial Investments" and "Asset Retirement Obligations," respectively, for information regarding our nuclear decommissioning trust (NDT) and our ARO.
- **La Cygne leasehold dismantling costs:** We are contractually obligated to dismantle a portion of La Cygne unit 2. This item represents amounts collected but not yet spent to dismantle this unit and the obligation will be discharged as we dismantle the unit.
- **Kansas tax credits:** This item represents Kansas tax credits on investments in utility plant. Amounts will be credited to customers subsequent to their realization over the remaining lives of the utility plant giving rise to the tax credits.
- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. We bill customers based on our estimated costs. This item represents the amount we collected from customers that was in excess of our actual cost of fuel and purchased power. We will refund to customers this excess recovery over a one-year period.
- **Purchase power agreement:** This item represents the amount included in retail electric rates from customers in excess of the costs incurred by us under the purchase power agreement with Westar Generating. We amortize the amount over a three-year period.
- **Other regulatory liabilities:** Includes various regulatory liabilities that individually are relatively small in relation to the total regulatory liability balance. Other regulatory liabilities will be credited over various periods.

KCC Proceedings

General and Abbreviated Rate Reviews

In September 2015, the KCC issued an order in our state general rate review allowing us to adjust our prices to include, among other things, additional investment in La Cygne environmental upgrades and investment to extend the life of Wolf Creek. The new prices were effective late October 2015 and are expected to increase our annual retail revenues by approximately $78.3 million. The KCC also approved our request to file an abbreviated rate review within 12 months of the effective date of this order to update our prices to include additional capital costs related to La Cygne environmental upgrades, investment to extend the life of Wolf Creek, costs related to programs to improve grid resiliency and costs associated with investments in other environmental projects during 2015.

In November 2013, the KCC issued an order in our state abbreviated rate review allowing us to adjust our prices to include additional investment in La Cygne environmental upgrades and to reflect cost reductions elsewhere. The new prices were expected to increase our annual retail revenues by approximately $30.7 million.

Environmental Costs

In October 2015, in connection with the state general rate review, we agreed to no longer make annual filings with the KCC to adjust our prices to include costs associated with investments in air quality equipment made during the prior year. The existing balance of costs associated with these investments were rolled into our base prices. In the future, we will need to seek approval from the KCC for individual projects. In the most recent three years, the KCC issued orders related to such filings allowing us to increase our annual retail revenues by approximately:

- $10.8 million effective in June 2015;
- $11.0 million effective in June 2014; and
- $27.3 million effective in June 2013.

Transmission Costs

We make annual filings with the KCC to adjust our prices to include updated transmission costs as reflected in our transmission formula rate (TFR) discussed below. In the most recent three years, the KCC issued orders related to such filings allowing us to increase our annual retail revenues by approximately:

- $7.2 million effective in April 2015;
- $41.0 million effective in April 2014; and
- $11.8 million effective in March 2013.

Property Tax Surcharge

We make annual filings with the KCC to adjust our prices to include the cost incurred for property taxes. In October 2015, in connection with the state general rate review, the existing balance of costs incurred for property taxes were rolled into our base prices. In the most recent four years, the KCC issued orders related to such filings allowing us to increase our annual retail revenues by approximately:

- $5.0 million effective in January 2016;
- $4.9 million effective in January 2015;
- $12.7 million effective in January 2014; and
- $15.2 million effective in January 2013.

FERC Proceedings

In October of each year, we post an updated TFR that includes projected transmission capital expenditures and operating costs for the following year. This rate provides the basis for our annual request with the KCC to adjust our retail prices to include updated transmission costs as noted above. In the most recent four years, we posted our TFR which was expected to adjust our annual transmission revenues by approximately:

- $21.6 million increase effective in January 2016;
- $4.6 million decrease effective in January 2015;
- $44.3 million increase effective in January 2014; and
- $12.2 million increase effective in January 2013.

In August 2014, the KCC filed a complaint against us with the Federal Energy Regulatory Commission (FERC) under Section 206 of the Federal Power Act (FPA). The complaint sought to lower our base return on equity (ROE) used in determining our TFR, which would result in a refund obligation and reduce our future transmission revenues. In June 2015, we filed a settlement agreement with the FERC, which if approved, would result in an ROE of 10.3%, which consists of a 9.8% base ROE plus a 0.5% incentive ROE for participation in an RTO. In July 2015, FERC staff filed comments supporting the proposed settlement. As a result, for the year ended December 31, 2015, we recorded a liability of $13.8 million for our estimated refund obligation from the refund effective date of August 20, 2014 through December 31, 2015. In addition, we estimate our future transmission revenues would be reduced by approximately $11.0 million on an annualized basis as a result of the reduced ROE.

4. FINANCIAL INSTRUMENTS AND TRADING SECURITIES

Values of Financial Instruments

GAAP establishes a hierarchical framework for disclosing the transparency of the inputs utilized in measuring assets and liabilities at fair value. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy levels. The three levels of the hierarchy and examples are as follows:

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities. The types of assets and liabilities included in level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed on public exchanges.
- Level 2 — Pricing inputs are not quoted prices in active markets, but are either directly or indirectly observable. The types of assets and liabilities included in level 2 are typically measured at net asset value, comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no transparency. The types of assets and liabilities included in level 3 are those with inputs requiring significant management judgment or estimation. Level 3 includes investments in private equity, real estate securities and other alternative investments, which are measured at net asset value.

We record cash and cash equivalents, short-term borrowings and variable rate debt on our consolidated balance sheets at cost, which approximates fair value. We measure the fair value of fixed rate debt, a level 2 measurement, based on quoted market prices for the same or similar issues or on the current rates offered for instruments of the same remaining maturities and redemption provisions. The recorded amount of accounts receivable and other current financial instruments approximates fair value.

All of our level 2 investments are held in investment funds that are measured at fair value using daily net asset values. In addition, we maintain certain level 3 investments in private equity, alternative investments and real estate securities that are also measured at fair value using net asset value, but require significant unobservable market information to measure the fair value of the underlying investments. The underlying investments in private equity are measured at fair value utilizing both market- and income-based models, public company comparables, investment cost or the value derived from subsequent financings. Adjustments are made when actual performance differs from expected performance; when market, economic or company-specific conditions change; and when other news or events have a material impact on the security. The underlying alternative investments include collateralized debt obligations, mezzanine debt and a variety of other investments. The fair value of these investments is measured using a variety of primarily market-based models utilizing inputs such as security prices, maturity, call features, ratings and other developments related to specific securities. The underlying real estate investments are measured at fair value using a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity.

We measure fair value based on information available as of the measurement date. The following table provides the carrying values and measured fair values of our fixed-rate debt.

	As of December 31, 2015		As of December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In Thousands)			
Fixed-rate debt	$ 3,080,000	$ 3,259,533	$ 3,105,000	$ 3,488,410
Fixed-rate debt of VIEs	166,271	179,030	194,204	213,579

Recurring Fair Value Measurements

The following table provides the amounts and their corresponding level of hierarchy for our assets that are measured at fair value.

As of December 31, 2015	Level 1	Level 2	Level 3	Total
	(In Thousands)			
Nuclear Decommissioning Trust:				
Domestic equity funds	$ —	$ 50,872	$ 6,050	$ 56,922
International equity funds	—	33,595	—	33,595
Core bond fund	—	25,976	—	25,976
High-yield bond fund	—	15,288	—	15,288
Emerging market bond fund	—	13,584	—	13,584
Combination debt/equity/ other funds	—	11,343	—	11,343
Alternative investment fund	—	—	16,439	16,439
Real estate securities fund	—	—	10,823	10,823
Cash equivalents	87	—	—	87
Total Nuclear Decommissioning Trust	87	150,658	33,312	184,057
Trading Securities:				
Domestic equity funds	—	17,876	—	17,876
International equity fund	—	4,430	—	4,430
Core bond fund	—	11,423	—	11,423
Cash equivalents	159	—	—	159
Total Trading Securities	159	33,729	—	33,888
Total Assets Measured at Fair Value	$ 246	$ 184,387	$ 33,312	$ 217,945

As of December 31, 2014	Level 1	Level 2	Level 3	Total
	(In Thousands)			
Nuclear Decommissioning Trust:				
Domestic equity funds	$ —	$ 54,925	$ 6,047	$ 60,972
International equity funds	—	30,791	—	30,791
Core bond fund	—	19,289	—	19,289
High-yield bond fund	—	13,198	—	13,198
Emerging market bond fund	—	10,988	—	10,988
Other fixed income fund	—	4,779	—	4,779
Combination debt/equity/ other funds	—	18,141	—	18,141
Alternative investment fund	—	—	16,970	16,970
Real estate securities fund	—	—	9,548	9,548
Cash equivalents	340	—	—	340
Total Nuclear Decommissioning Trust	340	152,111	32,565	185,016
Trading Securities:				
Domestic equity funds	—	18,698	—	18,698
International equity fund	—	4,252	—	4,252
Core bond fund	—	12,379	—	12,379
Cash equivalents	168	—	—	168
Total Trading Securities	168	35,329	—	35,497
Total Assets Measured at Fair Value	$ 508	$ 187,440	$ 32,565	$ 220,513

The following table provides reconciliations of assets held in the NDT measured at fair value using significant level 3 inputs for the years ended December 31, 2015 and 2014.

	Domestic Equity Funds	Alternative Investment Fund	Real Estate Securities Fund	Net Balance
	(In Thousands)			
Balance as of December 31, 2014	$ 6,047	$ 16,970	$ 9,548	$ 32,565
Total realized and unrealized gains and (losses) included in:				
Regulatory liabilities	899	(531)	1,275	1,643
Purchases	400	—	406	806
Sales	(1,296)	—	(406)	(1,702)
Balance as of December 31, 2015	$ 6,050	$ 16,439	$ 10,823	$ 33,312
Balance as of December 31, 2013	$ 5,817	$ 15,675	$ 8,511	$ 30,003
Total realized and unrealized gains and (losses) included in:				
Regulatory liabilities	391	1,295	1,037	2,723
Purchases	335	—	351	686
Sales	(496)	—	(351)	(847)
Balance as of December 31, 2014	$ 6,047	$ 16,970	$ 9,548	$ 32,565

Portions of the gains and losses contributing to changes in net assets in the above table are unrealized. The following table summarizes the unrealized gains and losses we recorded to regulatory liabilities on our consolidated financial statements during the years ended December 31, 2015 and 2014, attributed to level 3 assets. See Note 3, "Rate Matters and Regulation," for additional information regarding our regulatory assets and liabilities.

	Domestic Equity Funds	Alternative Investment Fund	Real Estate Securities Fund	Net Balance
	(In Thousands)			
Total unrealized gains (losses):				
Year ended December 31, 2015	$ (397)	$ (531)	$ 869	$ (59)
Year ended December 31, 2014	(105)	1,296	685	1,876

Some of our investments in the NDT and our trading securities portfolio are measured at net asset value and do not have readily determinable fair values. These investments are either with investment companies or companies that follow accounting guidance consistent with investment companies. In certain situations these investments may have redemption restrictions. The following table provides additional information on these investments.

	As of December 31, 2015		As of December 31, 2014		As of December 31, 2015	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
	(In Thousands)					
Nuclear Decommissioning Trust:						
Domestic equity funds	$ 6,050	$ 1,948	$ 6,047	$ 2,348	[a]	[a]
Alternative investment fund[b]	16,439	—	16,970	—	Quarterly	65 days
Real estate securities fund[c]	10,823	—	9,548	—	Quarterly	80 days
Total Nuclear Decommissioning Trust	$ 33,312	$ 1,948	$ 32,565	$ 2,348		
Trading Securities:						
Domestic equity funds	$ 17,876	$ —	$ 18,698	$ —	Upon Notice	1 day
International equity funds	4,430	—	4,252	—	Upon Notice	1 day
Core bond fund	11,423	—	12,379	—	Upon Notice	1 day
Total Trading Securities	33,729	—	35,329	—		
Total	$ 67,041	$ 1,948	$ 67,894	$ 2,348		

[a] *This investment is in three long-term private equity funds that do not permit early withdrawal. Our investments in these funds cannot be distributed until the underlying investments have been liquidated which may take years from the date of initial liquidation. Two funds have begun to make distributions. Our initial investment in the third fund occurred in the third quarter of 2013. This fund's term is expected to be 15 years, subject to the general partner's right to extend the term for up to three additional one-year periods.*

[b] *There is a holdback on final redemptions.*

[c] *In January 2016, we initiated a plan to sell this investment. We expect to receive proceeds in the amount of the investment's fair value, determined as of March 31, 2016.*

Derivative Instruments

Price Risk

We use various types of fuel, including coal, natural gas, uranium and diesel to operate our plants and also purchase power to meet customer demand. Our prices and consolidated financial results are exposed to market risks from commodity price changes for electricity and other energy-related products as well as from interest rates. Volatility in these markets impacts our costs of purchased power, costs of fuel for our generating plants and our participation in energy markets. We strive to manage our customers' and our exposure to market risks through regulatory, operating and financing activities and, when we deem appropriate, we economically hedge a portion of these risks through the use of derivative financial instruments for non-trading purposes.

Interest Rate Risk

We have entered into numerous fixed and variable rate debt obligations. For details, see Note 9, "Long-Term Debt." We manage our interest rate risk related to these debt obligations by limiting our exposure to variable interest rate debt, diversifying maturity dates and entering into treasury yield hedge transactions. We may also use other financial derivative instruments such as interest rate swaps.

5. FINANCIAL INVESTMENTS

We report our investments in equity and debt securities at fair value and use the specific identification method to determine their realized gains and losses. We classify these investments as either trading securities or available-for-sale securities as described below.

Trading Securities

We hold equity and debt investments which we classify as trading securities in a trust used to fund certain retirement benefit obligations. These obligations totaled $27.4 million and $29.8 million as of December 31, 2015 and 2014, respectively. For additional information on our benefit obligations, see Note 11, "Employee Benefit Plans."

As of December 31, 2015 and 2014, we measured the fair value of trust assets at $33.9 million and $35.5 million, respectively. We include unrealized gains or losses on these securities in investment earnings on our consolidated statements of income. For the years ended December 31, 2015, 2014 and 2013, we recorded unrealized gains of $0.4 million, $2.6 million and $6.7 million, respectively, on assets still held.

Available-for-Sale Securities

We hold investments in a trust for the purpose of funding the decommissioning of Wolf Creek. We have classified these investments as available-for-sale and have recorded all such investments at their fair market value as of December 31, 2015 and 2014.

Using the specific identification method to determine cost, we realized a loss on our available-for-sale securities of $0.9 million in 2015. In 2014 and 2013, we realized gains on our available-for-sale securities of $0.1 million and $5.3 million, respectively. We record net realized and unrealized gains and losses in regulatory liabilities on our consolidated balance sheets. This reporting is consistent with the method we use to account for the decommissioning costs we recover in our prices. Gains or losses on assets in the trust fund are recorded as increases or decreases, respectively, to regulatory liabilities and could result in lower or higher funding requirements for decommissioning costs, which we believe would be reflected in the prices paid by our customers.

The following table presents the cost, gross unrealized gains and losses, fair value and allocation of investments in the NDT fund as of December 31, 2015 and 2014.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Allocation
	(Dollars in Thousands)				
As of December 31, 2015:					
Domestic equity funds	$ 49,488	$ 7,436	$ (2)	$ 56,922	32%
International equity funds	33,458	1,372	(1235)	33,595	18%
Core bond fund	26,397	—	(421)	25,976	14%
High-yield bond fund	17,047	—	(1,759)	15,288	8%
Emerging market bond fund	16,306	—	(2,722)	13,584	7%
Combination debt/equity/other funds	8,239	3,104	—	11,343	6%
Alternative investment fund	15,000	1,439	—	16,439	9%
Real estate securities fund	11,026	—	(203)	10,823	6%
Cash equivalents	87	—	—	87	<1%
Total	$ 177,048	$ 13,351	$ (6,342)	$ 184,057	100%
As of December 31, 2014:					
Domestic equity funds	$ 46,126	$ 14,853	$ (7)	$ 60,972	33%
International equity funds	27,521	3,683	(413)	30,791	17%
Core bond fund	18,811	478	—	19,289	10%
High-yield bond fund	13,342	—	(144)	13,198	7%
Emerging market bond fund	12,556	—	(1,568)	10,988	6%
Other fixed income fund	4,798	—	(19)	4,779	3%
Combination debt/equity/other funds	14,975	3,786	(620)	18,141	10%
Alternative investment fund	15,000	1,970	—	16,970	9%
Real estate securities fund	10,619	—	(1,071)	9,548	5%
Cash equivalents	340	—	—	340	<1%
Total	$ 164,088	$ 24,770	$ (3,842)	$ 185,016	100%

The following table presents the fair value and the gross unrealized losses of the available-for-sale securities held in the NDT fund aggregated by investment category and the length of time that individual securities have been in a continuous unrealized loss position as of December 31, 2015 and 2014.

	Less than 12 Months		12 Months or Greater		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	(In Thousands)					
As of December 31, 2015:						
Domestic equity funds	$ —	$ —	$ 668	$ (2)	$ 668	$ (2)
International equity funds	—	—	6,717	(1,235)	6,717	(1,235)
Core bond funds	25,976	(421)	—	—	25,976	(421)
High-yield bond fund	15,288	(1,759)	—	—	15,288	(1,759)
Emerging market bond fund	—	—	13,584	(2,722)	13,584	(2,722)
Real estate securities fund	—	—	10,823	(203)	10,823	(203)
Total	$ 41,264	$ (2,180)	$31,792	$ (4,162)	$ 73,056	$ (6,342)
As of December 31, 2014:						
Domestic equity funds	$ —	$ —	$ 263	$ (7)	$ 263	$ (7)
International equity funds	5,905	(413)	—	—	5,905	(413)
High-yield bond fund	13,198	(144)	—	—	13,198	(144)
Emerging market bond fund	—	—	10,988	(1,568)	10,988	(1,568)
Other fixed income fund	4,779	(19)	—	—	4,779	(19)
Combination debt/equity/other funds	—	—	5,892	(620)	5,892	(620)
Real estate securities fund	—	—	9,548	(1,071)	9,548	(1,071)
Total	$ 23,882	$ (576)	$26,691	$ (3,266)	$ 50,573	$ (3,842)

6. PROPERTY, PLANT AND EQUIPMENT

The following is a summary of our property, plant and equipment balance.

As of December 31,	2015	2014
	(In Thousands)	
Electric plant in service	$ 11,449,933	$ 10,620,292
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(4,178,885)	(4,112,483)
	8,073,366	7,310,127
Construction work in progress	349,402	773,144
Nuclear fuel, net	68,349	79,637
Plant to be retired, net[(a)]	33,785	—
Net property, plant and equipment	$ 8,524,902	$ 8,162,908

[(a)] *Represents the retirement of analog meters prior to the end of their remaining useful lives due to modernization of meter technology.*

As of December 31,	2015	2014
	(In Thousands)	
Electric plant of VIEs	$ 497,999	$ 497,999
Accumulated depreciation of VIEs	(229,760)	(219,426)
Net property, plant and equipment of VIEs	$ 268,239	$ 278,573

We recorded depreciation expense on property, plant and equipment of $287.9 million in 2015, $263.8 million in 2014 and $249.9 million in 2013. Approximately $9.6 million, $9.7 million and $9.7 million of depreciation expense in 2015, 2014 and 2013, respectively, was attributable to property, plant and equipment of VIEs.

7. JOINT OWNERSHIP OF UTILITY PLANTS

Under joint ownership agreements with other utilities, we have undivided ownership interests in four electric generating stations. Energy generated and operating expenses are divided on the same basis as ownership with each owner reflecting its respective costs in its statements of income and each owner responsible for its own financing. Information relative to our ownership interests in these facilities as of December 31, 2015, is shown in the table below.

Plant	In-Service Dates	Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percentage
		(Dollars in Thousands)				
La Cygne unit 1[(a)]	June 1973	$ 602,599	$ 152,737	$ 22,461	368	50
JEC unit 1[(a)]	July 1978	816,051	188,649	800	670	92
JEC unit 2[(a)]	May 1980	546,955	200,286	10,112	651	92
JEC unit 3[(a)]	May 1983	715,624	325,599	18,959	654	92
Wolf Creek[(b)]	Sept. 1985	1,880,243	817,353	72,864	551	47
State Line[(c)]	June 2001	111,451	57,828	263	196	40
Total		$ 4,672,923	$ 1,742,452	$ 125,459	3,090	

[(a)] *Jointly owned with Kansas City Power & Light Company (KCPL). Our 8% leasehold interest in Jeffrey Energy Center (JEC) that is consolidated as a VIE is reflected in the net megawatts (MW) and ownership percentage provided above, but not in the other amounts in the table.*
[(b)] *Jointly owned with KCPL and Kansas Electric Power Cooperative, Inc.*
[(c)] *Jointly owned with Empire District Electric Company.*

We include in operating expenses on our consolidated statements of income our share of operating expenses of the above plants. Our share of fuel expense for the above plants is generally based on the amount of power we take from the respective plants. Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

In addition, we also consolidate a VIE that holds our 50% leasehold interest in La Cygne unit 2, which represents 331 MW of net capacity. The VIE's investment in the 50% interest was $392.1 million and accumulated depreciation was $201.6 million as of December 31, 2015. We include these amounts in property, plant and equipment of VIEs, net on our consolidated balance sheets. See Note 17, "Variable Interest Entities," for additional information about VIEs.

8. SHORT-TERM DEBT

In September 2015, Westar Energy extended the term of its $730.0 million revolving credit facility to terminate in September 2019, $20.7 million of which will expire in September 2017. As long as there is no default under the facility, Westar Energy may extend the facility up to an additional year and may increase the aggregate amount of borrowings under the facility to $1.0 billion, both subject to lender participation. All borrowings under the facility are secured by KGE first mortgage bonds. As of December 31, 2015, no amounts had been borrowed and $19.2 million of letters of credit had been issued under this revolving credit facility. As of December 31, 2014, no amounts had been borrowed and $15.6 million of letters of credit had been issued under this revolving credit facility.

In February 2014, Westar Energy extended the term of the $270.0 million revolving credit facility to February 2017, of which $20.0 million of this facility was scheduled to terminate in February 2016. In April 2015, the $20.0 million was extended to also terminate in February 2017. So long as there is no default under the facility, Westar Energy may increase the aggregate amount of borrowings under the facility to $400.0 million, subject to lender participation. All borrowings under the facility are secured by KGE first mortgage bonds. As of December 31, 2015 and 2014, Westar Energy had no borrowed amounts or letters of credit outstanding under this revolving credit facility.

Westar Energy maintains a commercial paper program pursuant to which it may issue commercial paper up to a maximum aggregate amount outstanding at any one time of $1.0 billion. This program is supported by Westar Energy's revolving credit facilities. Maturities of commercial paper issuances may not exceed 365 days from the date of issuance and proceeds from such issuances will be used to temporarily fund capital expenditures, to redeem debt on an interim basis, for working capital and/or for other general corporate purposes. Westar Energy had $250.3 million and $257.6 million of commercial paper issued and outstanding as of December 31, 2015 and 2014, respectively.

In addition, total combined borrowings under Westar Energy's commercial paper program and revolving credit facilities may not exceed $1.0 billion at any given time. The weighted average interest rate on short-term borrowings outstanding as of December 31, 2015 and 2014, was 0.77% and 0.52%, respectively. Additional information regarding our short-term debt is as follows.

Year Ended December 31,	2015	2014
	(Dollars In Thousands)	
Weighted average short-term debt outstanding	$ 350,380	$ 232,336
Weighted daily average interest rates, excluding fees	0.48%	0.30%

Our interest expense on short-term debt was $3.0 million in 2015, $2.0 million in 2014 and $2.4 million in 2013.

9. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

As of December 31,	2015	2014
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
5.15% due 2017	$ 125,000	$ 125,000
8.625% due 2018	—	300,000
5.10% due 2020	250,000	250,000
3.25% due 2025	250,000	—
5.95% due 2035	—	125,000
5.875% due 2036	—	150,000
4.125% due 2042	550,000	550,000
4.10% due 2043	430,000	430,000
4.625% due 2043	250,000	250,000
4.25% due 2045	300,000	—
	2,155,000	2,180,000
Pollution control bond series:		
Variable due 2032, 0.02% as of December 31, 2015; 0.06% as of December 31, 2014	45,000	45,000
Variable due 2032, 0.02% as of December 31, 2015; 0.08% as of December 31, 2014	30,500	30,500
	75,500	75,500
KGE		
First mortgage bond series:		
6.70% due 2019	300,000	300,000
6.15% due 2023	50,000	50,000
6.53% due 2037	175,000	175,000
6.64% due 2038	100,000	100,000
4.30% due 2044	250,000	250,000
	875,000	875,000
Pollution control bond series:		
Variable due 2027, 0.02% as of December 31, 2015; 0.08% as of December 31, 2014	21,940	21,940
4.85% due 2031[(c)]	50,000	50,000
Variable due 2032, 0.02% as of December 31, 2015; 0.08% as of December 31, 2014	14,500	14,500
Variable due 2032, 0.02% as of December 31, 2015; 0.08% as of December 31, 2014	10,000	10,000
	96,440	96,440
Total long-term debt	3,201,940	3,226,940
Unamortized debt discount[(a)]	(10,374)	(11,401)
Unamortized debt issuance expense[(a)]	(27,616)	(28,459)
Long-term debt, net	$ 3,163,950	$ 3,187,080
Variable Interest Entities		
5.92% due 2019[(b)]	$ 4,223	$ 8,413
5.647% due 2021[(b)]	162,048	185,791
Total long-term debt of variable interest entities	166,271	194,204
Unamortized debt premium[(a)]	135	294
Long-term debt of variable interest entities due within one year	(28,309)	(27,933)
Long-term debt of variable interest entities, net	$ 138,097	$ 166,565

(a) We amortize debt discounts and issuance expense to interest expense over the term of the respective issues.

(b) Portions of our payments related to this debt reduce the principal balances each year until maturity.

(c) KGE has entered into an agreement to refund this debt in June 2016.

The Westar Energy and KGE mortgages each contain provisions restricting the amount of first mortgage bonds that could be issued by each entity. We must comply with such restrictions prior to the issuance of additional first mortgage bonds or other secured indebtedness.

The amount of Westar Energy first mortgage bonds authorized by its Mortgage and Deed of Trust, dated July 1, 1939, as supplemented, is subject to certain limitations as described below. The amount of KGE first mortgage bonds authorized by the KGE Mortgage and Deed of Trust, dated April 1, 1940, as supplemented and amended, is limited to a maximum of $3.5 billion, unless amended further. First mortgage bonds are secured by utility assets. Amounts of additional bonds that may be issued are subject to property, earnings and certain restrictive provisions, except in connection with certain refundings, of each mortgage. As of December 31, 2015, approximately $851.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage. As of December 31, 2015, approximately $1.5 billion principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

As of December 31, 2015, we had $121.9 million of variable rate, tax-exempt bonds outstanding. While the interest rates for these bonds have been extremely low, we continue to monitor the credit markets and evaluate our options with respect to these bonds.

In February 2016, KGE, as lessee to the La Cygne sale-leaseback, effected a refunding of $162.1 million in outstanding bonds held by the trustee of the lease maturing March 2021. The stated interest rate of the bonds was reduced from 5.647% to 2.398%. See Note 17, "Variable Interest Entities," for additional information regarding our La Cygne sale-leaseback.

In November 2015, Westar Energy issued $250.0 million in principal amount of first mortgage bonds bearing stated interest at 3.25% and maturing December 2025. Concurrently, Westar Energy issued $300.0 million in principal amount of first mortgage bonds bearing stated interest at 4.25% and maturing December 2045.

Also in November 2015, Westar Energy redeemed $300.0 million in principal amount of first mortgage bonds bearing stated interest at 8.625% maturing in December 2018 for $360.9 million which included a call premium. The call premium was recorded as a regulatory asset and is being amortized over the term of the new bonds.

In August 2015, Westar Energy redeemed $150.0 million in principal amount of first mortgage bonds bearing stated interest at 5.875% and maturing July 2036.

In January 2015, Westar Energy redeemed $125.0 million in principal amount of first mortgage bonds bearing stated interest at 5.95% and maturing January 2035.

In July 2014, KGE issued $250.0 million in principal amount of first mortgage bonds bearing stated interest at 4.30% and maturing July 2044, the proceeds of which were used to retire Westar Energy first mortgage bonds in a principal amount of $250.0 million with a stated interest of 6.00% maturing in July 2014.

In June 2014, KGE redeemed $177.5 million in principal amount of pollution control bonds bearing stated interest rates between 5.00% and 5.30%.

In May 2014, Westar Energy issued $180.0 million in principal amount of first mortgage bonds bearing stated interest at 4.10% and maturing April 2043. These bonds constitute a further issuance of a series of bonds initially issued in March 2013 in a principal amount of $250.0 million.

Proceeds from issuances were used to repay short-term debt, which was used to purchase capital equipment, to redeem bonds and for working capital and general corporate purposes.

Maturities

The principal amounts of our long-term debt maturities as of December 31, 2015, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2016	$ —	$ 28,309
2017	125,000	26,842
2018	—	28,538
2019	300,000	31,485
2020	250,000	32,254
Thereafter	2,526,940	18,843
Total maturities	$ 3,201,940	$ 166,271

Interest expense on long-term debt, net of debt AFUDC, was $152.7 million in 2015, $158.8 million in 2014 and $154.9 million in 2013. Interest expense on long-term debt of VIEs was $9.8 million in 2015, $11.4 million in 2014 and $13.0 million in 2013.

10. TAXES

Income tax expense is comprised of the following components.

Year Ended December 31,	2015	2014	2013
		(In Thousands)	
Income Tax Expense (Benefit):			
Current income taxes:			
Federal	$ 327	$ 416	$ 135
State	341	(597)	279
Deferred income taxes:			
Federal	124,891	124,923	102,030
State	29,484	29,657	24,443
Investment tax credit amortization	(3,043)	(3,129)	(3,166)
Income tax expense	$ 152,000	$ 151,270	$ 123,721

The tax effect of the temporary differences and carryforwards that comprise our deferred tax assets and deferred tax liabilities are summarized in the following table.

As of December 31,	2015	2014
	(In Thousands)	
Deferred tax assets:		
Tax credit carryforward[a]	$ 266,963	$ 257,827
Net operating loss carryforward[b]	129,232	179,285
Deferred employee benefit costs	122,757	158,102
Deferred state income taxes	67,307	66,557
Deferred regulatory gain on sale-leaseback	33,287	35,706
Deferred compensation	27,266	29,315
Alternative minimum tax carryforward[c]	26,725	24,114
Accrued liabilities	21,115	23,048
Disallowed costs	10,211	10,829
LaCygne dismantling cost	10,018	9,064
Capital loss carryforward[d]	1,668	1,981
Other	41,319	27,689
Total gross deferred tax assets	757,868	823,517
Less: Valuation allowance[e]	1,668	1,981
Deferred tax assets	$ 756,200	$ 821,536
Deferred tax liabilities:		
Accelerated depreciation	$ 1,787,457	$ 1,664,367
Acquisition premium	155,881	163,894
Amounts due from customers for future income taxes, net	144,120	153,984
Deferred employee benefit costs	122,757	158,102
Deferred state income taxes	59,787	59,170
Debt reacquisition costs	42,314	20,102
Pension expense tracker	12,051	14,187
Storm costs	—	15,713
Other	23,263	17,868
Total deferred tax liabilities	$ 2,347,630	$ 2,267,387
Net deferred income tax liabilities	$ 1,591,430	$ 1,445,851

(a) Based on filed tax returns and amounts expected to be reported in current year tax returns (December 31, 2015), we had available federal general business tax credits of $80.9 million and state investment tax credits of $186.1 million. The federal general business tax credits were primarily generated from production tax credits. These tax credits expire beginning in 2020 and ending in 2035. The state investment tax credits expire beginning in 2017 and ending in 2031.

(b) As of December 31, 2015, we had a federal net operating loss carryforward of $326.5 million, which is available to offset federal taxable income. The net operating losses will expire beginning in 2031 and ending in 2034.

(c) As of December 31, 2015, we had available an alternative minimum tax credit carryforward of $26.7 million, which has an unlimited carryforward period.

(d) As of December 31, 2015, we had an unused capital loss carryforward of $4.2 million that is available to offset future capital gains. The capital losses will expire in 2016.

(e) As we do not expect to realize any significant capital gains in the future, we have established a valuation allowance of $1.7 million. The total valuation allowance related to the deferred tax assets was $1.7 million as of December 31, 2015, and $2.0 million as of December 31, 2014.

In accordance with various orders, we have reduced our prices to reflect the income tax benefits associated with certain accelerated income tax deductions. We believe it is probable that the net future increases in income taxes payable will be recovered from customers when these temporary income tax benefits reverse. We have recorded a regulatory asset for these amounts. We also have recorded a regulatory liability for our obligation to reduce the prices charged to customers for deferred income taxes recovered from customers at corporate income tax rates higher than current income tax rates. The price reduction will occur as the temporary differences resulting in the excess deferred income tax liabilities reverse. The income tax-related regulatory assets and liabilities as well as unamortized investment tax credits are also temporary differences for which deferred income taxes have been provided. The net deferred income tax liability related to these temporary differences is classified above as amounts due from customers for future income taxes, net.

Our effective income tax rates are computed by dividing total federal and state income taxes by the sum of such taxes and net income. The difference between the effective income tax rates and the federal statutory income tax rates are as follows.

Year Ended December 31,	2015	2014	2013
Statutory federal income tax rate	35.0%	35.0%	35.0%
Effect of:			
COLI policies	(4.4)	(4.0)	(5.4)
State income taxes	4.3	4.0	3.8
Flow through depreciation for plant-related differences	2.6	2.0	2.2
Production tax credits	(2.1)	(2.1)	(2.3)
Amortization of federal investment tax credits	(0.7)	(0.7)	(0.7)
AFUDC equity	(0.2)	(1.3)	(1.2)
Capital loss utilization carryforward	(0.1)	(0.3)	(1.1)
Liability for unrecognized income tax benefits	—	(0.2)	0.1
Other	(0.9)	(0.5)	(1.3)
Effective income tax rate	33.5%	31.9%	29.1%

We file income tax returns in the U.S. federal jurisdiction as well as various state jurisdictions. The income tax returns we file will likely be audited by the Internal Revenue Service or other tax authorities. With few exceptions, the statute of limitations with respect to U.S. federal or state and local income tax examinations by tax authorities remains open for tax year 2012 and forward.

The unrecognized income tax benefits decreased from $3.2 million at December 31, 2014, to $2.9 million at December 31, 2015. The decrease for unrecognized income tax benefits was largely attributable to tax positions expected to be taken with respect to potential deductions related to an environmental settlement agreement in a tax period for which the statute of limitations has closed. We do not expect significant changes in the unrecognized

income tax benefits in the next 12 months. A reconciliation of the beginning and ending amounts of unrecognized income tax benefits is as follows:

	2015	2014	2013
		(In Thousands)	
Unrecognized income tax benefits as of January 1	$ 3,188	$ 1,703	$ 1,219
Additions based on tax positions related to the current year	410	872	224
Additions for tax positions of prior years	—	813	325
Reductions for tax positions of prior years	(86)	(200)	(65)
Lapse of statute of limitations	(611)	—	—
Settlements	—	—	—
Unrecognized income tax benefits as of December 31	$ 2,901	$ 3,188	$ 1,703

The amounts of unrecognized income tax benefits that, if recognized, would favorably impact our effective income tax rate, were $2.9 million, $3.2 million and $2.4 million (net of tax) as of December 31, 2015, 2014 and 2013, respectively.

Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. As of December 31, 2015 and 2014, we had no amounts accrued for interest related to unrecognized income tax benefits. We accrued no penalties at either December 31, 2015 or 2014.

As of December 31, 2015 and 2014, we had recorded $1.5 million for probable assessments of taxes other than income taxes.

11. EMPLOYEE BENEFIT PLANS

Pension and Post-Retirement Benefit Plans

We maintain a qualified non-contributory defined benefit pension plan covering substantially all of our employees. For the majority of our employees, pension benefits are based on years of service and an employee's compensation during the 60 highest paid consecutive months out of 120 before retirement. Non-union employees hired after December 31, 2001, and union employees hired after December 31, 2011, are covered by the same defined benefit pension plan; however, their benefits are derived from a cash balance account formula. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain retired executive officers. We have discontinued accruing any future benefits under this non-qualified plan.

The amount we contribute to our pension plan for future periods is not yet known, however, we expect to fund our pension plan each year at least to a level equal to current year pension expense. We must also meet minimum funding requirements under the Employee Retirement Income Security Act, as amended by the Pension Protection Act. We may contribute additional amounts from time to time as deemed appropriate.

In addition to providing pension benefits, we provide certain post-retirement health care and life insurance benefits for substantially all retired employees. We accrue and recover in our prices the costs of post-retirement benefits during an employee's years of service. In 2014 and prior years, our retirees were covered under a health insurance policy. In January 2015, we began giving our retirees a fixed annual allowance, which provides them the flexibility to obtain health coverage in the marketplace that is tailored to their needs.

As a co-owner of Wolf Creek, KGE is indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement benefit plans. See Note 12, "Wolf Creek Employee Benefit Plans," for information about Wolf Creek's benefit plans.

The following tables summarize the status of our pension and post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2015	2014	2015	2014
		(In Thousands)		
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 1,030,645	$ 823,780	$ 141,516	$ 133,061
Service cost	21,392	16,218	1,443	1,381
Interest cost	43,014	41,600	5,691	6,351
Plan participants' contributions	—	—	582	4,232
Benefits paid	(44,945)	(39,225)	(6,549)	(12,184)
Actuarial (gains) losses	(90,644)	188,272	(16,399)	16,509
Amendments	5,731	—	—	(7,834)
Benefit obligation, end of year[(a)]	$ 965,193	$1,030,645	$ 126,284	$ 141,516
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 661,141	$ 609,817	$ 121,349	$ 121,766
Actual return on plan assets	(6,948)	61,291	(208)	7,189
Employer contributions	41,000	26,400	—	—
Plan participants' contributions	—	—	534	4,074
Benefits paid	(41,248)	(36,367)	(6,259)	(11,680)
Fair value of plan assets, end of year	$ 653,945	$ 661,141	$ 115,416	$ 121,349
Funded status, end of year	$ (311,248)	$ (369,504)	$ (10,868)	$ (20,167)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (2,745)	$ (2,716)	$ (344)	$ (246)
Noncurrent liability	(308,503)	(366,788)	(10,524)	(19,921)
Net amount recognized	$ (311,248)	$ (369,504)	$ (10,868)	$ (20,167)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss (gain)	$ 254,085	$ 329,572	$ (12,208)	$ (2,253)
Prior service cost	8,078	2,867	3,130	3,585
Net amount recognized	$ 262,163	$ 332,439	$ (9,078)	$ 1,332

[(a)] *As of December 31, 2015 and 2014, pension benefits include non-qualified benefit obligations of $27.4 million and $29.8 million, respectively, which are funded by a trust containing assets of $33.9 million and $35.5 million, respectively, classified as trading securities. The assets in the aforementioned trust are not included in the table above. See Notes 4 and 5, "Financial Instruments and Trading Securities" and "Financial Investments," respectively, for additional information regarding these amounts.*

As of December 31,	Pension Benefits 2015	Pension Benefits 2014	Post-retirement Benefits 2015	Post-retirement Benefits 2014
	(In Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 965,193	$1,030,645	$ —	$ —
Fair value of plan assets	653,945	661,141	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 864,263	$ 914,800	—	—
Fair value of plan assets	653,945	661,141	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	—	—	$ 126,284	$141,516
Fair value of plan assets	—	—	115,416	121,349
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	4.60%	4.17%	4.51%	4.10%
Compensation rate increase	4.00%	4.00%	—	—

We use a measurement date of December 31 for our pension and post-retirement benefit plans. The discount rate used to determine the current year pension obligation and the following year's pension expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality, non-callable corporate bonds that generate sufficient cash flow to provide for the projected benefit payments of the plan. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected. The increase in the discount rates used as of December 31, 2015, decreased the pension and post-retirement benefit obligations by approximately $59.6 million and $5.8 million, respectively.

We utilize actuarial assumptions about mortality to calculate the pension and post-retirement benefit obligations. In 2015, a revised mortality table was issued reflecting updated future projections of life expectancies based on additional years of actual mortality experience. We adopted a modified version of the revised mortality table as of December 31, 2015, resulting in a decrease to the pension and post-retirement benefit obligations by approximately $27.3 million and $1.8 million, respectively.

We amortize prior service cost on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. We amortize the net actuarial gain or loss on a straight-line basis over the average future service of active plan participants benefiting under the plan without application of an amortization corridor. The KCC allows us to record a regulatory asset or liability to track the cumulative difference between current year pension and post-retirement benefits expense and the amount of such expense recognized in setting our prices. We accumulate such regulatory asset or liability between general rate reviews and amortize the accumulated amount as part of resetting our base prices. Following is additional information regarding our pension and post-retirement benefit plans.

Year Ended December 31,	Pension Benefits 2015	Pension Benefits 2014	Pension Benefits 2013
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 21,392	$ 16,218	$ 21,420
Interest cost	43,014	41,600	38,520
Expected return on plan assets	(40,236)	(36,438)	(33,405)
Amortization of unrecognized:			
Transition obligation, net	—	—	—
Prior service costs	520	526	601
Actuarial loss (gain), net	32,131	19,362	33,914
Net periodic cost before regulatory adjustment	56,821	41,268	61,050
Regulatory adjustment[a]	6,886	15,479	3,693
Net periodic cost	$ 63,707	$ 56,747	$ 64,743
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain) loss	$ (43,459)	$ 162,569	$(163,086)
Amortization of actuarial (loss) gain	(32,379)	(19,362)	(33,914)
Current year prior service cost	5,730	—	—
Amortization of prior service costs	(520)	(526)	(601)
Amortization of transition obligation	—	—	—
Other adjustments	352	—	—
Total recognized in regulatory assets	$ (70,276)	$ 142,681	$(197,601)
Total recognized in net periodic cost and regulatory assets	$ (6,569)	$ 199,428	$(132,858)
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	4.17%	5.07%	4.13%
Expected long-term return on plan assets	6.50%	6.50%	6.50%
Compensation rate increase	4.00%	4.00%	4.00%

[a] *The regulatory adjustment represents the difference between current period pension or post-retirement benefit expense and the amount of such expense recognized in setting our prices.*

Year Ended December 31,	Post-retirement Benefits 2015	2014	2013
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 1,443	$ 1,381	$ 2,028
Interest cost	5,691	6,351	6,007
Expected return on plan assets	(6,614)	(6,576)	(6,691)
Amortization of unrecognized:			
Transition obligation, net	—	—	325
Prior service costs	455	2,524	2,524
Actuarial loss (gain), net	379	(742)	1,125
Net periodic cost before regulatory adjustment	1,354	2,938	5,318
Regulatory adjustment[a]	4,096	4,499	2,922
Net periodic cost	$ 5,450	$ 7,437	$ 8,240
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain) loss	$ (9,576)	$ 15,896	$ (30,201)
Amortization of actuarial (loss) gain	(379)	742	(1,125)
Current year prior service cost	—	(7,834)	—
Amortization of prior service costs	(455)	(2,524)	(2,525)
Amortization of transition obligation	—	—	(325)
Other adjustments	—	—	—
Total recognized in regulatory assets	$ (10,410)	$ 6,280	$ (34,176)
Total recognized in net periodic cost and regulatory assets	$ (4,960)	$ 13,717	$ (25,936)
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	4.10%	4.88%	3.99%
Expected long-term return on plan assets	6.00%	6.00%	6.00%
Compensation rate increase	4.00%	4.00%	4.00%

[a] *The regulatory adjustment represents the difference between current period pension or post-retirement benefit expense and the amount of such expense recognized in setting our prices.*

We estimate that we will amortize the following amounts from regulatory assets and regulatory liabilities into net periodic cost in 2016.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss (gain)	$ 20,559	$ (1,118)
Prior service cost	987	455
Total	$ 21,546	$ (663)

We base the expected long-term rate of return on plan assets on historical and projected rates of return for current and planned asset classes in the plans' investment portfolios. We select assumed projected rates of return for each asset class after analyzing long-term historical experience and future expectations of the volatility of the various asset classes. Based on target asset allocations for each asset class, we develop an overall expected rate of return for the portfolios, adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

Plan Assets

We believe we manage pension and post-retirement benefit plan assets in a prudent manner with regard to preserving principal while providing reasonable returns. We have adopted a long-term investment horizon such that the chances and duration of investment losses are weighed against the long-term potential for appreciation of assets. Part of our strategy includes managing interest rate sensitivity of plan assets relative to the associated liabilities. The primary objective of the pension plan is to provide a source of retirement income for its participants and beneficiaries, and the primary financial objective of the plan is to improve its funded status. The primary objective of the post-retirement benefit plan is growth in assets and preservation of principal, while minimizing interim volatility, to meet anticipated claims of plan participants. We delegate the management of our pension and post-retirement benefit plan assets to independent investment advisors who hire and dismiss investment managers based upon various factors. The investment advisors are instructed to diversify investments across asset classes, sectors and manager styles to minimize the risk of large losses, based upon objectives and risk tolerance specified by management, which include allowable and/or prohibited investment types. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

We have established certain prohibited investments for our pension and post-retirement benefit plans. Such prohibited investments include loans to the company or its officers and directors as well as investments in the company's debt or equity securities, except as may occur indirectly through investments in diversified mutual funds. In addition, to reduce concentration of risk, the pension plan will not invest in any fund that holds more than 25% of its total assets to be invested in the securities of one or more issuers conducting their principal business activities in the same industry. This restriction does not apply to investments in securities issued or guaranteed by the U.S. government or its agencies.

Target allocations for our pension plan assets are approximately 39% to debt securities, 39% to equity securities, 12% to alternative investments such as real estate securities, hedge funds and private equity investments, and the remaining 10% to a fund which provides tactical portfolio overlay by investing in debt and equity securities. Our investments in equity include investment funds with underlying investments in domestic and foreign large-, mid- and small-cap companies, derivatives related to such holdings, private equity investments including late-stage venture investments and other investments. Our investments in debt include core and high-yield

bonds. Core bonds are comprised of investment funds with underlying investments in investment grade debt securities of corporate entities, obligations of U.S. and foreign governments and their agencies and other debt securities. High-yield bonds include investment funds with underlying investments in non-investment grade debt securities of corporate entities, obligations of foreign governments and their agencies, private debt securities and other debt securities. Real estate securities consist primarily of funds invested in core real estate throughout the U.S. while alternative funds invest in wide ranging investments including equity and debt securities of domestic and foreign corporations, debt securities issued by U.S. and foreign governments and their agencies, structured debt, warrants, exchange-traded funds, derivative instruments, private investment funds and other investments.

Target allocations for our post-retirement benefit plan assets are 65% to equity securities and 35% to debt securities. Our investments in equity securities include investment funds with underlying investments primarily in domestic and foreign large-, mid- and small-cap companies. Our investments in debt securities include a core bond fund with underlying investments in investment grade debt securities of domestic and foreign corporate entities, obligations of U.S. and foreign governments and their agencies, private placement securities and other investments.

Similar to other assets measured at fair value, GAAP establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring pension and post-retirement benefit plan assets at fair value. From time to time, the pension and post-retirement benefits trusts may buy and sell investments resulting in changes within the hierarchy. See Note 4, "Financial Instruments and Trading Securities," for a description of the hierarchal framework.

All level 2 pension investments are held in investment funds that are measured at fair value using daily net asset values as reported by the trustee, invested directly in long-term U.S. Treasury securities. We also maintain certain level 3 investments in private equity, alternative investments and real estate securities that are also measured at fair value using net asset value, but require significant unobservable market information to measure the fair value of the underlying investments. The underlying investments in private equity are measured at fair value utilizing both market- and income-based models, public company comparables, investment cost or the value derived from subsequent financings. Adjustments are made when actual performance differs from expected performance; when market, economic or company-specific conditions change; and when other news or events have a material impact on the security. The underlying alternative investments include collateralized debt obligations, mezzanine debt and a variety of other investments. The fair value of these investments is measured using a variety of primarily market-based models utilizing inputs such as security prices, maturity, call features, ratings and other developments related to specific securities. The underlying real estate investments are measured at fair value using a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity.

The following table provides the fair value of our pension plan assets and the corresponding level of hierarchy as of December 31, 2015 and 2014.

As of December 31, 2015	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity funds	$ —	$ 165,506	$ 25,277	$ 190,783
International equity fund	—	75,453	—	75,453
Emerging market equity fund	—	20,798	—	20,798
Domestic bond fund	—	105,279	—	105,279
Core bond funds	—	99,726	—	99,726
High-yield bond fund	—	28,288	—	28,288
Emerging market bond fund	—	23,019	—	23,019
Combination debt/equity/other fund	—	36,151	—	36,151
Alternative investment funds	—	—	39,557	39,557
Real estate securities fund	—	—	30,173	30,173
Cash equivalents	—	4,718	—	4,718
Total Assets Measured at Fair Value	$ —	$ 558,938	$ 95,007	$ 653,945

As of December 31, 2014	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity funds	$ —	$ 160,574	$ 23,996	$ 184,570
International equity fund	—	82,604	—	82,604
Core bond funds	—	224,740	—	224,740
High-yield bond fund	—	20,412	—	20,412
Emerging market bond fund	—	14,685	—	14,685
Combination debt/equity/other fund	—	61,632	—	61,632
Alternative investment funds	—	—	41,141	41,141
Real estate securities fund	—	—	26,439	26,439
Cash equivalents	—	4,918	—	4,918
Total Assets Measured at Fair Value	$ —	$ 569,565	$ 91,576	$ 661,141

The following table provides a reconciliation of pension plan assets measured at fair value using significant level 3 inputs for the years ended December 31, 2015 and 2014.

	Domestic Equity Funds	Alternative Investment Funds	Real Estate Securities Fund	Total
		(In Thousands)		
Balance as of December 31, 2014	$ 23,996	$ 41,141	$ 26,439	$ 91,576
Actual gain (loss) on plan assets:				
Relating to assets still held at the reporting date	934	(1,584)	3,944	3,294
Relating to assets sold during the period	2,755	—	60	2,815
Purchases, issuances and settlements, net	(2,408)	—	(270)	(2,678)
Balance as of December 31, 2015	$ 25,277	$ 39,557	$ 30,173	$ 95,007
Balance as of December 31, 2013	$ 22,488	$ 39,171	$ 24,022	$ 85,681
Actual gain (loss) on plan assets:				
Relating to assets still held at the reporting date	(154)	1,970	2,630	4,446
Relating to assets sold during the period	1,365	—	29	1,394
Purchases, issuances and settlements, net	297	—	(242)	55
Balance as of December 31, 2014	$ 23,996	$ 41,141	$ 26,439	$ 91,576

The following table provides the fair value of our post-retirement benefit plan assets and the corresponding level of hierarchy as of December 31, 2015 and 2014.

As of December 31, 2015	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity funds	$ —	$ 59,946	$ —	$ 59,946
International equity fund	—	14,419	—	14,419
Core bond funds	—	40,475	—	40,475
Cash equivalents	—	576	—	576
Total Assets Measured at Fair Value	$ —	$ 115,416	$ —	$ 115,416

As of December 31, 2014	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity funds	$ —	$ 63,600	$ —	$ 63,600
International equity fund	—	14,783	—	14,783
Core bond funds	—	42,390	—	42,390
Cash equivalents	—	576	—	576
Total Assets Measured at Fair Value	$ —	$ 121,349	$ —	$ 121,349

Cash Flows

The following table shows the expected cash flows for our pension and post-retirement benefit plans for future years.

	Pension Benefits		Post-retirement Benefits	
Expected Cash Flows	To/(From) Trust	(From) Company Assets	To/(From) Trust	(From) Company Assets
		(In Millions)		
Expected contributions:				
2016	$ 28.0		$ —	
Expected benefit payments:				
2016	$ (54.0)	$ (2.8)	$ (7.4)	$ (0.4)
2017	(55.0)	(2.8)	(7.7)	(0.3)
2018	(57.4)	(2.7)	(7.9)	(0.3)
2019	(59.3)	(2.7)	(8.1)	(0.3)
2020	(61.4)	(2.7)	(8.3)	(0.3)
2021-2025	(318.3)	(12.6)	(41.2)	(1.1)

Savings Plans

We maintain a qualified 401(k) savings plan in which most of our employees participate. We match employees' contributions in cash up to specified maximum limits. Our contributions to the plan are deposited with a trustee and invested at the direction of plan participants into one or more of the investment alternatives we provide under the plan. Our contributions totaled $7.7 million in 2015, $7.0 million in 2014 and $6.9 million in 2013.

Stock-Based Compensation Plans

We have a long-term incentive and share award plan (LTISA Plan), which is a stock-based compensation plan in which employees and directors are eligible for awards. The LTISA Plan was implemented as a means to attract, retain and motivate employees and directors. Under the LTISA Plan, we may grant awards in the form of stock options, dividend equivalents, share appreciation rights, RSUs, performance shares and performance share units to plan participants. Up to 8.25 million shares of common stock may be granted under the LTISA Plan. As of December 31, 2015, awards of approximately 5.0 million shares of common stock had been made under the plan.

All stock-based compensation is measured at the grant date based on the fair value of the award and is recognized as an expense in the consolidated statement of income over the requisite service period. The requisite service periods range from one to ten years. The table below shows compensation expense and income tax benefits related to stock-based compensation arrangements that are included in our net income.

Year Ended December 31,	2015	2014	2013
		(In Thousands)	
Compensation expense	$ 8,250	$ 7,193	$ 8,121
Income tax benefits related to stock-based compensation arrangements	3,263	2,845	3,212

We use RSU awards for our stock-based compensation awards. RSU awards are grants that entitle the holder to receive shares of common stock as the awards vest. These RSU awards are defined as nonvested shares and do not include restrictions once the awards have vested.

RSU awards with only service requirements vest solely upon the passage of time. We measure the fair value of these RSU awards based on the market price of the underlying common stock as of the grant date. RSU awards with only service conditions that have a graded vesting schedule are recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for the entire award. Nonforfeitable dividend equivalents, or the rights to receive cash equal to the value of dividends paid on Westar Energy's common stock, are paid on these RSUs during the vesting period.

RSU awards with performance measures vest upon expiration of the award term. The number of shares of common stock awarded upon vesting will vary from 0% to 200% of the RSU award, with performance tied to our total shareholder return relative to the total shareholder return of our peer group. We measure the fair value of these RSU awards using a Monte Carlo simulation technique that

uses the closing stock price at the valuation date and incorporates assumptions for inputs of the expected volatility and risk-free interest rates. Expected volatility is based on historical volatility over three years using daily stock price observations. The risk-free interest rate is based on treasury constant maturity yields as reported by the Federal Reserve and the length of the performance period. For the 2015 valuation, inputs for expected volatility ranged from 14.6% to 19.1% and the risk-free interest rate was approximately 1.0%. For the 2014 valuation, inputs for expected volatility ranged from 15.2% to 23.3% and the risk-free interest rate was approximately 0.3%. For these RSU awards, dividend equivalents accumulate over the vesting period and are paid in cash based on the number of shares of common stock awarded upon vesting.

During the years ended December 31, 2015, 2014 and 2013, our RSU activity for awards with only service requirements was as follows.

As of December 31,	2015		2014		2013	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value
	(Shares in Thousands)					
Nonvested balance, beginning of year	342.2	$ 31.38	352.5	$ 28.38	351.1	$ 25.47
Granted	115.7	39.50	131.5	34.53	139.6	31.06
Vested	(115.4)	28.77	(118.2)	26.19	(125.5)	23.22
Forfeited	(32.6)	33.07	(23.6)	30.00	(12.7)	28.35
Nonvested balance, end of year	309.9	35.21	342.2	31.38	352.5	28.38

Total unrecognized compensation cost related to RSU awards with only service requirements was $4.5 million and $4.4 million as of December 31, 2015 and 2014, respectively. We expect to recognize these costs over a remaining weighted-average period of 1.7 years. The total fair value of RSUs with only service requirements that vested during the years ended December 31, 2015, 2014 and 2013, was $4.7 million, $3.9 million and $3.7 million, respectively.

During the years ended December 31, 2015, 2014 and 2013, our RSU activity for awards with performance measures was as follows.

As of December 31,	2015		2014		2013	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value
	(Shares in Thousands)					
Nonvested balance, beginning of year	345.1	$ 32.31	350.1	$ 30.35	340.1	$ 29.20
Granted	94.8	40.26	126.1	35.97	134.4	31.54
Vested	(109.0)	28.99	(108.2)	30.56	(112.5)	28.29
Forfeited	(31.8)	34.03	(22.9)	30.70	(11.9)	30.45
Nonvested balance, end of year	299.1	36.00	345.1	32.31	350.1	30.35

As of December 31, 2015 and 2014, total unrecognized compensation cost related to RSU awards with performance measures was $4.0 million and $3.8 million, respectively. We expect to recognize these costs over a remaining weighted-average period of 1.7 years. The total fair value of RSUs with performance measures that vested during the years ended December 31, 2015, 2014 and 2013, was $3.1 million, $0.5 million and $2.3 million, respectively.

Another component of the LTISA Plan is the Executive Stock for Compensation program under which, in the past, eligible employees were entitled to receive deferred common stock in lieu of current cash compensation. Although this plan was discontinued in 2001, dividends will continue to be paid to plan participants on their outstanding plan balance until distribution. Plan participants were awarded 296 shares of common stock for dividends in 2015, 403 shares in 2014 and 551 shares in 2013. Participants received common stock distributions of 2,024 shares in 2015, 1,944 shares in 2014 and 3,456 shares in 2013.

Income tax benefits resulting from income tax deductions in excess of the related compensation cost recognized in the financial statements is classified as cash flows from financing activities in the consolidated statements of cash flows.

12. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefit Plans

As a co-owner of Wolf Creek, KGE is indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement benefit plans. KGE accrues its 47% share of Wolf Creek's cost of pension and post-retirement benefits during the years an employee provides service. The following tables summarize the status of KGE's 47% share of the Wolf Creek pension and post-retirement benefit plans.

As of December 31,	Pension Benefits 2015	Pension Benefits 2014	Post-retirement Benefits 2015	Post-retirement Benefits 2014
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 210,320	$ 162,820	$ 8,240	$ 10,010
Service cost	7,595	5,695	138	173
Interest cost	9,016	8,469	314	464
Plan participants' contributions	—	—	934	766
Benefits paid	(6,217)	(5,039)	(1,622)	(1,292)
Actuarial (gains) losses	(14,296)	38,375	(211)	(1,881)
Benefit obligation, end of year	$ 206,418	$ 210,320	$ 7,793	$ 8,240
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 124,660	$ 114,734	$ 6	$ 17
Actual return on plan assets	(2,879)	7,626	—	—
Employer contributions	5,805	7,089	787	515
Plan participants' contributions	—	—	934	766
Benefits paid	(5,964)	(4,789)	(1,622)	(1,292)
Fair value of plan assets, end of year	$ 121,622	$ 124,660	$ 105	$ 6
Funded status, end of year	$ (84,796)	$ (85,660)	$ (7,688)	$ (8,234)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (247)	$ (247)	$ (597)	$ (575)
Noncurrent liability	(84,549)	(85,413)	(7,091)	(7,659)
Net amount recognized	$ (84,796)	$ (85,660)	$ (7,688)	$ (8,234)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss (gain)	$ 56,747	$ 65,049	$ (184)	$ 29
Prior service cost	501	559	—	—
Net amount recognized	$ 57,248	$ 65,608	$ (184)	$ 29

As of December 31,	Pension Benefits 2015	Pension Benefits 2014	Post-retirement Benefits 2015	Post-retirement Benefits 2014
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 206,418	$ 210,320	$ —	$ —
Fair value of plan assets	121,622	124,660	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 180,718	$ 179,228	$ —	$ —
Fair value of plan assets	121,622	124,660	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 7,793	$ 8,240
Fair value of plan assets	—	—	105	6
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	4.61%	4.20%	4.27%	3.89%
Compensation rate increase	4.00%	4.00%	—	—

Wolf Creek uses a measurement date of December 31 for its pension and post-retirement benefit plans. The discount rate used to determine the current year pension obligation and the following year's pension expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality, non-callable corporate bonds that generate sufficient cash flow to provide for the projected benefit payments of the plan. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected. The increase in the discount rates used as of December 31, 2015, decreased Wolf Creek's pension and post-retirement benefit obligations by approximately $12.4 million and $0.3 million, respectively.

Wolf Creek utilizes actuarial assumptions about mortality to calculate the pension and post-retirement benefit obligations. In 2015, a revised mortality table was issued reflecting updated future projections of life expectancies based on additional years of actual mortality experience. Wolf Creek adopted a modified version of the revised mortality table as of December 31, 2015, resulting in a decrease to the pension benefit obligation by approximately $4.8 million.

The prior service cost (benefit) is amortized on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. The net actuarial gain or loss is amortized on a straight-line basis over the average future service of active plan participants benefiting under the plan without application of an amortization corridor. Following is additional information regarding KGE's 47% share of the Wolf Creek pension and other post-retirement benefit plans.

Year Ended December 31,	Pension Benefits 2015	2014	2013
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 7,595	$ 5,695	$ 6,835
Interest cost	9,016	8,469	7,562
Expected return on plan assets	(9,044)	(8,084)	(7,373)
Amortization of unrecognized:			
Prior service costs	57	58	58
Actuarial loss, net	5,930	2,987	5,421
Net periodic cost before regulatory adjustment	13,554	9,125	12,503
Regulatory adjustment[a]	(1,485)	2,328	(641)
Net periodic cost	$ 12,069	$ 11,453	$ 11,862
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain) loss	$ (2,373)	$ 38,833	$ (29,911)
Amortization of actuarial gain	(5,930)	(2,987)	(5,421)
Amortization of prior service cost	(57)	(58)	(58)
Total recognized in regulatory assets	$ (8,360)	$ 35,788	$ (35,390)
Total recognized in net periodic cost and regulatory assets	$ 3,709	$ 47,241	$ (23,528)
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	4.20%	5.11%	4.16%
Expected long-term return on plan assets	7.50%	7.50%	7.50%
Compensation rate increase	4.00%	4.00%	4.00%

[a] *The regulatory adjustment represents the difference between current period pension or post-retirement benefit expense and the amount of such expense recognized in setting our prices.*

Year Ended December 31,	Post-retirement Benefits 2015	2014	2013
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 138	$ 173	$ 206
Interest cost	314	464	413
Expected return on plan assets	—	—	—
Amortization of unrecognized:			
Prior service costs	—	—	—
Actuarial loss, net	3	165	265
Net periodic cost before regulatory adjustment	455	802	884
Regulatory adjustment[a]	—	—	—
Net periodic cost	$ 455	$ 802	$ 884
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain) loss	$ (211)	$ (1,881)	$ (1,303)
Amortization of actuarial gain	(3)	(165)	(265)
Amortization of prior service cost	—	—	—
Total recognized in regulatory assets	$ (214)	$ (2,046)	$ (1,568)
Total recognized in net periodic cost and regulatory assets	$ 241	$ (1,244)	$ (684)
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	3.89%	4.70%	3.78%
Expected long-term return on plan assets	—	—	—
Compensation rate increase	—	—	—

[a] *The regulatory adjustment represents the difference between current period pension or post-retirement benefit expense and the amount of such expense recognized in setting our prices.*

We estimate that we will amortize the following amounts from regulatory assets and regulatory liabilities into net periodic cost in 2016.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss (gain)	$ 4,357	$ (14)
Prior service cost	55	—
Total	$ 4,412	$ (14)

The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolios. Assumed projected rates of return for each asset class were selected after analyzing long-term historical experience and future expectations of the volatility of the various asset classes. Based on target asset allocations for each asset class, the overall expected rate of return for the portfolios was developed, adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

For measurement purposes, the assumed annual health care cost growth rates were as follows.

As of December 31,	2015	2014
Health care cost trend rate assumed for next year	7.0%	7.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2020	2019

The health care cost trend rate affects the projected benefit obligation. A 1% change in assumed health care cost growth rates would have effects shown in the following table.

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(In Thousands)	
Effect on total of service and interest cost	$ (8)	$ 8
Effect on post-retirement benefit obligation	(95)	97

Plan Assets

Wolf Creek's pension and post-retirement plan investment strategy is to manage assets in a prudent manner with regard to preserving principal while providing reasonable returns. It has adopted a long-term investment horizon such that the chances and duration of investment losses are weighed against the long-term potential for appreciation of assets. Part of its strategy includes managing interest rate sensitivity of plan assets relative to the associated liabilities. The primary objective of the pension plan is to provide a source of retirement income for its participants and beneficiaries, and the primary financial objective of the plan is to improve its funded status. The primary objective of the post-retirement benefit plan is growth in assets and preservation of principal, while minimizing interim volatility, to meet anticipated claims of plan participants. Wolf Creek delegates the management of its pension and post-retirement benefit plan assets to independent investment advisors who hire and dismiss investment managers based upon various factors. The investment advisors are instructed to diversify investments across asset classes, sectors and manager styles to minimize the risk of large losses, based upon objectives and risk tolerance specified by Wolf Creek, which include allowable and/or prohibited investment types. It measures and monitors investment risk on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

The target allocations for Wolf Creek's pension plan assets are 31% to international equity securities, 25% to domestic equity securities, 25% to debt securities, 10% to real estate securities, 5% to commodity investments and 4% to other investments. The investments in both international and domestic equity include investments in large-, mid- and small-cap companies, private equity funds and investment funds with underlying investments similar to those previously mentioned. The investments in debt include core and high-yield bonds. Core bonds include funds invested in investment grade debt securities of corporate entities, obligations of U.S. and foreign governments and their agencies and private debt securities. High-yield bonds include a fund with underlying investments in non-investment grade debt securities of corporate entities, private placements and bank debt. Real estate securities include funds invested in commercial and residential real estate properties while commodity investments include funds invested in commodity-related instruments.

All of Wolf Creek's pension plan assets are recorded at fair value using daily net asset values as reported by the trustee. However, level 3 investments in real estate funds and alternative funds are invested in underlying investments that are illiquid and require significant judgment when measuring them at fair value using market- and income-based models. Significant unobservable inputs for underlying real estate investments include estimated market discount rates, projected cash flows and estimated value into perpetuity. Alternative funds invest in a wide range of investments typically with low correlations to traditional investments.

Similar to other assets measured at fair value, GAAP establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring pension and post-retirement benefit plan assets at fair value. From time to time, the Wolf Creek pension trust may buy and sell investments resulting in changes within the hierarchy. See Note 4, "Financial Instruments and Trading Securities," for a description of the hierarchal framework.

The following table provides the fair value of KGE's 47% share of Wolf Creek's pension plan assets and the corresponding level of hierarchy as of December 31, 2015 and 2014.

As of December 31, 2015	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity funds	$ —	$ 30,503	$ —	$ 30,503
International equity funds	—	37,682	—	37,682
Core bond funds	—	30,287	—	30,287
Real estate securities fund	—	6,123	6,434	12,557
Commodities fund	—	5,811	—	5,811
Alternative investment fund	—	—	4,258	4,258
Cash equivalents	—	524	—	524
Total Assets Measured at Fair Value	$ —	$110,930	$ 10,692	$ 121,622

As of December 31, 2014	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity funds	$ —	$ 31,580	$ —	$ 31,580
International equity funds	—	38,624	—	38,624
Core bond funds	—	31,854	—	31,854
Real estate securities fund	—	6,313	5,649	11,962
Commodities fund	—	5,887	—	5,887
Alternative investment fund	—	—	4,309	4,309
Cash equivalents	—	444	—	444
Total Assets Measured at Fair Value	$ —	$114,702	$ 9,958	$ 124,660

The following table provides a reconciliation of KGE's 47% share of Wolf Creek's pension plan assets measured at fair value using significant level 3 inputs for the years ended December 31, 2015 and 2014.

	Real Estate Securities Fund	Alternative Investment Fund	Total
	(In Thousands)		
Balance as of December 31, 2014	$ 5,649	$ 4,309	$ 9,958
Actual gain (loss) on plan assets:			
Relating to assets still held at the reporting date	785	(51)	734
Balance as of December 31, 2015	$ 6,434	$ 4,258	$10,692
Balance as of December 31, 2013	$ 5,094	$ 4,147	$ 9,241
Actual gain on plan assets:			
Relating to assets still held at the reporting date	555	162	717
Balance as of December 31, 2014	$ 5,649	$ 4,309	$ 9,958

Cash Flows

The following table shows our expected cash flows for KGE's 47% share of Wolf Creek's pension and post-retirement benefit plans for future years.

	Pension Benefits		Post-retirement Benefits	
Expected Cash Flows	To/(From) Trust	(From) Company Assets	To/(From) Trust	(From) Company Assets
	(In Millions)			
Expected contributions:				
2016	$ 8.0		$ 0.6	
Expected benefit payments:				
2016	$ (6.0)	$ (0.3)	$ (1.8)	$ —
2017	(6.9)	(0.3)	(2.0)	—
2018	(7.8)	(0.3)	(2.3)	—
2019	(8.7)	(0.3)	(2.6)	—
2020	(9.6)	(0.3)	(2.9)	—
2021 – 2025	(61.3)	(1.3)	(18.2)	—

Savings Plan

Wolf Creek maintains a qualified 401(k) savings plan in which most of its employees participate. Wolf Creek matches employees' contributions in cash up to specified maximum limits. Wolf Creek's contributions to the plan are deposited with a trustee and invested at the direction of plan participants into one or more of the investment alternatives provided under the plan. KGE's portion of the expense associated with Wolf Creek's matching contributions was $1.6 million in 2015, $1.4 million in 2014 and $1.4 million in 2013.

13. COMMITMENTS AND CONTINGENCIES

Purchase Orders and Contracts

As part of our ongoing operations and capital expenditure program, we have purchase orders and contracts, excluding fuel and transmission, which are discussed below under "— Fuel, Purchased Power and Transmission Commitments." These commitments relate to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments as of December 31, 2015, was as follows.

	Committed Amount
	(In Thousands)
2016[a]	$ 757,250
2017	13,199
2018	48,744
Thereafter	31,720
Total amount committed	$ 850,913

[a] *Significant portion related to construction commitments.*

Environmental Matters

Federal Clean Air Act

We must comply with the federal Clean Air Act (CAA), state laws and implementing federal and state regulations that impose, among other things, limitations on emissions generated from our operations, including sulfur dioxide (SO_2), particulate matter (PM), nitrogen oxides (NOx), carbon monoxide (CO), mercury and acid gases.

Emissions from our generating facilities, including PM, SO_2 and NOx, have been determined by regulation to reduce visibility by causing or contributing to regional haze. Under federal laws, such as the Clean Air Visibility Rule, and pursuant to an agreement with the Kansas Department of Health and Environment (KDHE) and the Environmental Protection Agency (EPA), we are required to install, operate and maintain controls to reduce emissions found to cause or contribute to regional haze.

Sulfur Dioxide and Nitrogen Oxide

Through the combustion of fossil fuels at our generating facilities, we emit SO_2 and NOx. Federal and state laws and regulations, including those noted above, and permits issued to us limit the amount of these substances we can emit. If we exceed these limits, we could be subject to fines and penalties. In order to meet SO_2 and NOx regulations applicable to our generating facilities, we use low-sulfur coal and natural gas and have equipped the majority of our fossil fuel generating facilities with equipment to control such emissions.

We are subject to the SO_2 allowance and trading program under the federal Clean Air Act Acid Rain Program. Under this program, each unit must have enough allowances to cover its SO_2 emissions for that year. In 2015, we had adequate SO_2 allowances to meet generation and we expect to have enough to cover emissions under this program in 2016.

Cross-State Air Pollution Rule

In November 2015, the EPA proposed the Cross-State Air Pollution Update Rule. The proposed rule addresses interstate transport of NOx emissions in 23 states including Kansas, Missouri and Oklahoma during the ozone season and the impact from the formation of ozone on downwind states with respect to the 2008 ozone National Ambient Air Quality Standards (NAAQS). Starting with the 2017 ozone season, the proposed rule will revise the existing ozone season allowance budgets for Missouri and Oklahoma and will establish an ozone season budget for Kansas. We are currently evaluating the impact of the proposed rule on our operations, and it could have a material impact on our operations and consolidated financial results.

National Ambient Air Quality Standards

Under the federal CAA, the EPA sets NAAQS for certain emissions considered harmful to public health and the environment, including two classes of PM, ozone, NOx (a precursor to ozone), CO and SO_2, which result from fossil fuel combustion. Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS. NAAQS must be reviewed by the EPA at five-year intervals.

In October 2015, the EPA strengthened the ozone NAAQS by lowering the standards from 75 parts per billion (ppb) to 70 ppb. As a result of this change, the EPA is required to make attainment/nonattainment designations for the revised standards by October 2017. We are currently reviewing this final rule and cannot at this time predict the impact it may have on our operations. Nonattainment designations in or surrounding our areas of operations could have a material impact on our consolidated financial results.

In December 2012, the EPA strengthened an existing NAAQS for one class of PM. In December 2014, the EPA designated the entire state of Kansas as unclassifiable/in attainment with the standard. We cannot at this time predict the impact this designation may have on our operations or consolidated financial results, but it could be material.

In 2010, the EPA revised the NAAQS for SO_2. In March 2015, a federal court approved a consent decree between the EPA and environmental groups. The decree includes specific SO_2 emissions criteria for certain electric generating plants that, if met, requires the EPA to promulgate attainment/nonattainment designations for areas surrounding these plants by July 2016. Tecumseh Energy Center is our only generating station that meets this criteria. We are working with KDHE to determine the appropriate designation for the areas surrounding the facility. In addition, we continue to communicate with our regulatory agencies regarding these standards and evaluate what impact the revised NAAQS could have on our operations and consolidated financial results. If areas surrounding our facilities are designated as nonattainment and/or we are required to install additional equipment to control emissions at our facilities, it could have a material impact on our operations and consolidated financial results.

Greenhouse Gases

Byproducts of burning coal and other fossil fuels include carbon dioxide (CO_2) and other gases referred to as greenhouse gases (GHG), which are believed by many to contribute to climate change. Various regulations under the federal CAA limit CO_2 and other GHG emissions, and other measures are being imposed or offered by individual states, municipalities and regional agreements with the goal of reducing GHG emissions.

In October 2015, the EPA published a rule establishing new source performance standards that limit CO_2 emissions for new, modified and reconstructed coal and natural gas fueled electric generating units to various levels per Megawatt hour (MWh) depending on various characteristics of the units. In October 2015, the EPA also published a rule establishing guidelines for states to regulate CO_2 emissions from existing power plants. The standards for existing plants are known as the Clean Power Plan (CPP). Under the CPP, interim emissions performance rates must be achieved beginning in 2022 and final emissions performance rates must be achieved by 2030. Legal challenges to the CPP were filed by groups of states and industry members, including our company, in the U.S. Court of Appeals for the D.C. Circuit beginning in October 2015, and more challenges are expected. In January 2016, the U.S. Court of Appeals for the D.C. Circuit denied a request to stay the CPP pending review. However, the U.S. Court of Appeals for the D.C. Circuit placed the case on an expedited review schedule with oral arguments scheduled for June 2016. Based on the U.S. Court of Appeals for the D.C. Circuit denial of the petition for stay, state and industry groups petitioned the U.S. Supreme Court for a stay. In February 2016, the U.S. Supreme Court granted the stay request. Due to the future uncertainty of the CPP, we cannot at this time determine the impact on our operations or consolidated financial results, but we believe the costs to comply could be material.

Mercury and Air Toxics Standards

In 2012, the Mercury and Air Toxics Standards (MATS) rule became effective. Under the MATS rule the EPA regulates the emissions of mercury, non-mercury metals, acid gases and organics. MATS required compliance to begin in April 2015, three years after the effective date. Sources could petition their state air regulatory agency to ask for an additional year to prepare for compliance. We petitioned the KDHE and our petition request was granted. Our current compliance date is April 2016 for all of our MATS affected units.

In June 2015, the U.S. Supreme Court reversed and remanded a decision by the U.S. Court of Appeals for the District of Columbia Circuit regarding the need for the EPA to consider costs during the initial phase of MATS development. In December 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an order leaving MATS in effect while EPA develops a final cost determination. The Court anticipates this final determination to be completed prior to the MATS compliance deadline in April 2016. Based on the final MATS rule, we do not expect there to be a material impact on our operations or consolidated financial results.

Water

We discharge some of the water used in our operations. This water may contain substances deemed to be pollutants. Revised rules governing such discharges from coal-fired power plants were issued in November 2015. The final rule establishes limitations or forces the elimination of wastewater associated with coal combustion residual handling. Implementation timelines for these requirements will vary from 2019 to 2023. We are evaluating the final rule at this time and cannot predict the resulting impact on our operations or consolidated financial results, but believe costs to comply could be material.

In October 2014, the EPA's final standards for cooling intake structures at power plants to protect aquatic life took effect. The standards, based on Section 316(b) of the federal Clean Water Act (CWA), require subject facilities to choose among seven best available technology options to reduce fish impingement. In addition, some facilities must conduct studies to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms. Our current analysis indicates this rule will not have a significant impact on our coal plants that employ cooling towers. Biological monitoring may be required for La Cygne and Wolf Creek. We are currently evaluating the rule's impact on those two plants and cannot predict the resulting impact on our operations or consolidated financial results, but we do not expect it to be material.

In June 2015, the EPA along with the U.S. Army Corps of Engineers issued a final rule, effective August 2015, defining the Waters of the United States for purposes of the CWA. This rulemaking has the potential to impact all programs under the CWA. Expansion of regulated waterways is possible under the rule depending on regulating authority interpretation, which could impact several permitting programs. Various states have filed lawsuits challenging the rule and, in October 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order that temporarily stays implementation of the rule nationwide pending the outcome of the various legal challenges. We are currently evaluating the final rule. The resulting impact of the rule could have a material impact on our operations or consolidated financial results.

Regulation of Coal Combustion Byproducts

In the course of operating our coal generation plants, we produce coal combustion byproducts (CCBs), including fly ash, gypsum and bottom ash. We recycle some of our ash production, principally by selling to the aggregate industry. The EPA published a rule to regulate CCBs in April 2015, which we believe will require additional CCB handling, processing and storage equipment and closure of certain ash disposal areas. While we cannot at this time estimate the full impact and costs associated with future regulations of CCBs, we have recorded an increase of approximately $34.4 million to our ARO and property, plant and equipment to recognize estimated future costs associated with closure and post-closure of disposal sites. We believe further impact on our operations or consolidated financial results could be material. See Note 14, "Asset Retirement Obligations," for additional information.

SPP Revenue Crediting

We are a member of the Southwest Power Pool, Inc. (SPP) Regional Transmission Organization, which coordinates the operation of a multistate interconnected transmission system. The SPP has been engaged in a process whereby it is seeking to allocate revenue credits under its Open Access Transmission Tariff to sponsors of certain transmission system upgrades. Qualifying upgrades are those that are not financed through general rates paid by all customers and that result in additional revenue to the SPP. The SPP is also evaluating whether sponsors are entitled to revenue credits for previously completed upgrades, and whether members will be obligated to pay for revenue credits attributable to these historical upgrades.

We believe it is reasonably possible that we will be required to pay sponsors for revenue credits attributable to historical upgrades. However, due to the complexity of the process, including the large number of transmission service requests associated with the upgrades at issue, the number of years included in the process and complexity surrounding the manner in which revenue credits are allocated, we are unable to estimate an amount, or a range of amounts, we may owe, or the impact on our consolidated financial results.

Renewable Energy Standard

In May 2015, Kansas repealed a state mandate to maintain a minimum amount of renewable energy sources, effective January 1, 2016.

Nuclear Decommissioning

Nuclear decommissioning is a nuclear industry term for the permanent shutdown of a nuclear power plant and the removal of radioactive components in accordance with Nuclear Regulatory Commission (NRC) requirements. The NRC will terminate a plant's license and release the property for unrestricted use when a company has reduced the residual radioactivity of a nuclear plant to a level mandated by the NRC. The NRC requires companies with nuclear plants to prepare formal financial plans to fund nuclear decommissioning. These plans are designed so that sufficient funds required for nuclear decommissioning will be accumulated prior to the expiration of the license of the related nuclear power plant. Wolf Creek files a nuclear decommissioning site study with the KCC every three years.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the updated nuclear decommissioning study including the estimated costs to decommission the plant. Phase two involves the review and approval of a funding schedule prepared by the owner of the plant detailing how it plans to fund the future-year dollar amount of its pro rata share of the decommissioning costs.

In 2014, Wolf Creek updated the nuclear decommissioning cost study. Based on the study, our share of decommissioning costs, including decontamination, dismantling and site restoration, is estimated to be approximately $360.0 million. This amount compares to the prior site study estimate of $296.2 million. The site

study cost estimate represents the estimate to decommission Wolf Creek as of the site study year. The actual nuclear decommissioning costs may vary from the estimates because of changes in regulations and technologies as well as changes in costs for labor, materials and equipment.

We are allowed to recover nuclear decommissioning costs in our prices over a period equal to the operating license of Wolf Creek, which is through 2045. The NRC requires that funds sufficient to meet nuclear decommissioning obligations be held in a trust. We believe that the KCC approved funding level will also be sufficient to meet the NRC requirement. Our consolidated financial results would be materially affected if we were not allowed to recover in our prices the full amount of the funding requirement.

We recovered in our prices and deposited in an external trust fund for nuclear decommissioning approximately $2.8 million in 2015, $2.8 million in 2014 and $2.9 million in 2013. We record our investment in the NDT fund at fair value, which approximated $184.1 million and $185.0 million as of December 31, 2015 and 2014, respectively.

Storage of Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek paid into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. In November 2013, a federal court of appeals ruled that the DOE must stop collecting this fee effective May 2014. Our share of the fee, calculated as one tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers, was $0.8 million in 2014 and $3.0 million in 2013. We included these costs in fuel and purchased power expense on our consolidated statements of income.

In 2010, the DOE filed a motion with the NRC to withdraw its then pending application to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada. An NRC board denied the DOE's motion to withdraw its application and the DOE appealed that decision to the full NRC. In 2011, the NRC issued an evenly split decision on the appeal and also ordered the licensing board to close out its work on the DOE's application by the end of 2011 due to a lack of funding. These agency actions prompted the states of Washington and South Carolina, and a county in South Carolina, to file a lawsuit in a federal Court of Appeals asking the court to compel the NRC to resume its license review and to issue a decision on the license application. In August 2013, the court ordered the NRC to resume its review of the DOE's application. The NRC has not yet issued its decision.

Wolf Creek is currently evaluating alternatives for expanding its existing on-site spent nuclear fuel storage to provide additional capacity prior to 2025. We cannot predict when, or if, an off-site storage site or alternative disposal site will be available to receive Wolf Creek's spent nuclear fuel and will continue to monitor this activity.

Nuclear Insurance

We maintain nuclear liability, property and business interruption insurance for Wolf Creek. These policies contain certain industry standard terms, conditions and exclusions, including, but not limited to, ordinary wear and tear and war. An industry aggregate limit of $3.2 billion plus any reinsurance, indemnity or any other source recoverable by Nuclear Electric Insurance Limited (NEIL), our property and business interruption insurance provider, exists for acts of terrorism affecting Wolf Creek or any other NEIL insured plant within 12 months from the date of the first act. In addition, we are required to participate in industry-wide retrospective assessment programs as discussed below.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, which has been reauthorized through December 2025 by the Energy Policy Act of 2005, we are required to insure against public liability claims resulting from nuclear incidents to the current limit of public liability, which is approximately $13.5 billion. This limit of liability consists of the maximum available commercial insurance of $375.0 million and the remaining $13.1 billion is provided through mandatory participation in an industry-wide retrospective assessment program. In addition, Congress could impose additional revenue-raising measures to pay claims. Under this retrospective assessment program, the owners of Wolf Creek are jointly and severally subject to an assessment of up to $127.3 million (our share is $59.8 million), payable at no more than $19.0 million (our share is $8.9 million) per incident per year per reactor. Both the total and yearly assessment is subject to an inflationary adjustment every five years with the next adjustment in 2018.

Nuclear Property and Business Interruption Insurance

The owners of Wolf Creek carry decontamination liability, premature nuclear decommissioning liability and property damage insurance for Wolf Creek totaling approximately $2.8 billion. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the NRC. Our share of any remaining proceeds can be used to pay for property damage or, if certain requirements are met, including decommissioning the plant, toward a shortfall in the NDT fund. The owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, we may be subject to retrospective assessments under the current policies of approximately $42.0 million (our share is $19.7 million).

Accidental Nuclear Outage Insurance

Although we maintain various insurance policies to provide coverage for potential losses and liabilities resulting from an accident or an extended outage, our insurance coverage may not be adequate to cover the costs that could result from a catastrophic accident or extended outage at Wolf Creek. Any substantial losses not covered by insurance, to the extent not recoverable in our prices, would have a material effect on our consolidated financial results.

Fuel, Purchased Power and Transmission Commitments

To supply a portion of the fuel requirements for our power plants, the owners of Wolf Creek have entered into various contracts to obtain nuclear fuel and we have entered into various contracts to obtain coal and natural gas. Some of these contracts contain provisions for price escalation and minimum purchase commitments. As of December 31, 2015, our share of Wolf Creek's nuclear fuel commitments was approximately $16.7 million for uranium concentrates expiring in 2017, $2.5 million for conversion expiring in 2017, $94.6 million for enrichment expiring in 2027 and $33.2 million for fabrication expiring in 2025.

As of December 31, 2015, our coal and coal transportation contract commitments under the remaining terms of the contracts were approximately $827.8 million. The contracts are for plants that we operate and expire at various times through 2020.

As of December 31, 2015, our natural gas transportation contract commitments under the remaining terms of the contracts were approximately $109.6 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2030.

We have power purchase agreements with the owners of nine separate wind generation facilities with installed design capabilities of approximately 1,314 MW expiring in 2028 through 2036. Of the approximately 1,314 MW under contract, approximately 400 MW are associated with agreements pursuant to which generation providers are scheduled to deliver power beginning by early 2017. Each of the agreements provide for our receipt and purchase of energy produced at a fixed price per unit of output. We estimate that our annual cost of energy purchased from these wind generation facilities will be approximately $104.8 million in 2016 and approximately $145.0 million for the next several years thereafter.

We have acquired rights to transmit a total of 206 MW. These agreements providing transmission capacity for 206 MW expire in 2016. As of December 31, 2015, we are committed to spend approximately $7.1 million over the remaining terms of these agreements.

FERC Proceedings

See Note 3, "Rate Matters and Regulation — FERC Proceedings," for information regarding a pending settlement of a complaint that was filed by the KCC against us with the FERC under Section 206 of the FPA.

14. ASSET RETIREMENT OBLIGATIONS

Legal Liability

We have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. The recording of AROs for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or an offset to a regulatory liability.

We initially recorded AROs at fair value for the estimated cost to decommission Wolf Creek (KGE's 47% share), retire our wind generation facilities, dispose of asbestos insulating material at our power plants, remediate ash disposal ponds and dispose of polychlorinated biphenyl (PCB)-contaminated oil.

The following table summarizes our legal AROs included on our consolidated balance sheets in long-term liabilities.

As of December 31,	2015	2014
	(In Thousands)	
Beginning ARO	$ 230,668	$ 160,682
Increase in nuclear decommissioning ARO liability	—	50,683
Increase in other ARO liabilities	34,440	9,580
Liabilities settled	(1,553)	(593)
Accretion expense	12,964	10,316
Revisions in estimated cash flows	(1,234)	—
Ending ARO	$ 275,285	$ 230,668

In 2015, we recorded an approximately $34.4 million increase in our ARO in response to the EPA's published rule to regulate CCBs. The increase is to recognize costs associated with closure and post-closure of disposal sites to be compliant. See Note 13, "Commitments and Contingencies — Regulation of Coal Combustion Byproducts," for additional information.

Wolf Creek filed a nuclear decommissioning cost study with the KCC in 2014. As a result of the study, we recorded in 2014 a $50.7 million increase in our ARO to reflect revisions to the estimated costs to decommission Wolf Creek.

Conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. We determined that our conditional AROs include the retirement of our wind generation facilities, disposal of asbestos insulating material at our power plants, the remediation of ash disposal ponds and the disposal of PCB-contaminated oil.

We have an obligation to retire our wind generation facilities and remove the foundations. The ARO related to our owned wind generation facilities was determined based upon the date each wind generation facility was placed into service.

The amount of the retirement obligation related to asbestos disposal was recorded as of 1990, the date when the EPA published the "National Emission Standards for Hazardous Air Pollutants: Asbestos NESHAP Revision; Final Rule."

We operate, as permitted by the state of Kansas, ash landfills at several of our power plants. The retirement obligation for the ash landfills was determined based upon the date each landfill was originally placed in service.

PCB-contaminated oil is contained within company electrical equipment, primarily transformers. The PCB retirement obligation was determined based upon the PCB regulations that originally became effective in 1978.

Non-Legal Liability — Cost of Removal

We collect in our prices the costs to dispose of plant assets that do not represent legal retirement obligations. As of December 31, 2015 and 2014, we had $53.8 million and $88.2 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability.

15. LEGAL PROCEEDINGS

We and our subsidiaries are involved in various legal, environmental and regulatory proceedings. We believe that adequate provisions have been made and accordingly believe that the ultimate disposition of such matters will not have a material effect on our consolidated financial results. See Notes 3 and 13, "Rate Matters and Regulation" and "Commitments and Contingencies," for additional information.

16. COMMON STOCK

General

Westar Energy's Restated Articles of Incorporation, as amended, provide for 275.0 million authorized shares of common stock. As of December 31, 2015 and 2014, Westar Energy had issued 141.4 million shares and 131.7 million shares, respectively.

Westar Energy has a direct stock purchase plan (DSPP). Shares of common stock sold pursuant to the DSPP may be either original issue shares or shares purchased in the open market. During 2015 and 2014, Westar Energy issued 0.5 million shares and 0.5 million shares, respectively, through the DSPP and other stock-based plans operated under the LTISA Plan. As of December 31, 2015 and 2014, a total of 1.2 million shares and 1.6 million shares, respectively, were available under the DSPP registration statement.

Issuances

In September 2013, Westar Energy entered into two forward sale agreements with two banks. Under the terms of the agreements, the banks, as forward sellers, borrowed 8.0 million shares of Westar Energy's common stock from third parties and sold them to a group of underwriters for $31.15 per share. Pursuant to over-allotment options granted to the underwriters, the underwriters purchased in October 2013 an additional 0.9 million shares from the banks as forward sellers, increasing the total number of shares under the forward sale agreements to approximately 8.9 million. The underwriters received a commission equal to 3.5% of the sales price of all shares sold under each agreement.

In March 2013, Westar Energy entered into a three-year sales agency financing agreement and master forward sale agreement with a bank. The maximum amount that Westar Energy may offer and sell under the March 2013 master agreements is the lesser of an aggregate of $500.0 million or approximately 25.0 million shares, subject to adjustment for share splits, share combinations and share dividends. Under the terms of the sales agency financing agreement, Westar Energy may offer and sell shares of its common stock from time to time. In addition, under the terms of the sales agency financing agreement and master forward sale confirmation, Westar Energy may from time to time enter into one or more forward sale transactions with the bank, as forward purchaser and the bank will borrow shares of Westar Energy's common stock from third parties and sell them through its agent. The agent receives a commission equal to 1% of the sales price of all shares sold under the agreements.

In April 2010, Westar Energy entered into a three-year sales agency financing agreement and master forward sale agreement with a bank that was terminated in March 2013. The maximum amount that Westar Energy could offer and sell under the agreements was the lesser of an aggregate of $500.0 million or approximately 22.0 million shares, subject to adjustment for share splits, share combinations and share dividends. Terms under these agreements were generally similar to the March 2013 agreements described above.

The following table summarizes our common stock activity pursuant to the three forward sale agreements.

Year Ended December 31,	2015	2014	2013
Shares that could be settled at beginning of year	9,160,500	12,052,976	1,753,415
Transactions entered	—	—	11,367,673
Transactions settled[a]	9,160,500	2,892,476	1,068,112
Shares that could be settled at end of year	—	9,160,500	12,052,976

[a] *The shares settled during the years ended December 31, 2015, 2014 and 2013, were settled with a physical settlement amount of approximately $254.6 million, $82.9 million and $27.0 million, respectively.*

The forward sale transactions were entered into at market prices; therefore, the forward sale agreements had no initial fair value. Westar Energy did not receive any proceeds from the sale of common stock under the forward sale agreements until transactions were settled. Westar Energy settled the forward sale transactions through physical share settlement and recorded the forward sale agreements within equity. The shares under the forward sale agreements were initially priced when the transactions were entered into and were subject to certain fixed pricing adjustments during the term of the agreements. The net proceeds from the forward sale transactions represent the prices established by the forward sale agreements applicable to the time periods in which physical settlement occurred.

Westar Energy used the proceeds from the transactions described above to repay short-term borrowings, with such borrowed amounts principally used for investments in capital equipment, as well as for working capital and general corporate purposes.

17. VARIABLE INTEREST ENTITIES

In determining the primary beneficiary of a VIE, we assess the entity's purpose and design, including the nature of the entity's activities and the risks that the entity was designed to create and pass through to its variable interest holders. A reporting enterprise is deemed to be the primary beneficiary of a VIE if it has (a) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses or right to receive benefits from the VIE that could potentially be significant to the VIE. The primary beneficiary of a VIE is required to consolidate the VIE. The trusts holding our 8% interest in JEC and our 50% interest in La Cygne unit 2 are VIEs of which we are the primary beneficiary.

We assess all entities with which we become involved to determine whether such entities are VIEs and, if so, whether or not we are the primary beneficiary of the entities. We also continuously assess whether we are the primary beneficiary of the VIEs with which we are involved. Prospective changes in facts and circumstances may cause us to reconsider our determination as it relates to the identification of the primary beneficiary.

8% Interest in Jeffrey Energy Center

Under an agreement that expires in January 2019, we lease an 8% interest in JEC from a trust. The trust was financed with an equity contribution from an owner participant and debt issued by the trust. The trust was created specifically to purchase the 8% interest in JEC and lease it to a third party, and does not hold any other assets. We meet the requirements to be considered the primary beneficiary of the trust. In determining the primary beneficiary of the trust, we concluded that the activities of the trust that most significantly impact its economic performance and that we have the power to direct include (1) the operation and maintenance of the 8% interest in JEC, (2) our ability to exercise a purchase option at the end of the agreement at the lesser of fair value or a fixed amount and (3) our option to require refinancing of the trust's debt. We have the potential to receive benefits from the trust that could potentially be significant if the fair value of the 8% interest in JEC at the end of the agreement is greater than the fixed amount. The possibility of lower interest rates upon refinancing the debt also creates the potential for us to receive significant benefits.

50% Interest in La Cygne Unit 2

Under an agreement that expires in September 2029, KGE entered into a sale-leaseback transaction with a trust under which the trust purchased KGE's 50% interest in La Cygne unit 2 and subsequently leased it back to KGE. The trust was financed with an equity contribution from an owner participant and debt issued by the trust. The trust was created specifically to purchase the 50% interest in La Cygne unit 2 and lease it back to KGE, and does not hold any other assets. We meet the requirements to be considered the primary beneficiary of the trust. In determining the primary beneficiary of the trust, we concluded that the activities of the trust that most significantly impact its economic performance and that we have the power to direct include (1) the operation and maintenance of the 50% interest in La Cygne unit 2 and (2) our ability to exercise a purchase option at the end of the agreement at the lesser of fair value or a fixed amount. We have the potential to receive benefits from the trust that could potentially be significant if the fair value of the 50% interest in La Cygne unit 2 at the end of the agreement is greater than the fixed amount. In February 2016, KGE effected a refunding of the $162.1 million in outstanding bonds maturing March 2021. See Note 9, "Long-term Debt," for additional information.

Railcars

Under two separate agreements, we leased railcars from unrelated trusts to transport coal to some of our power plants. We consolidated the trusts as VIEs until the agreements expired in November 2014 and May 2013. As a result of deconsolidating the trusts, property, plant and equipment of VIEs, net and noncontrolling interests decreased $7.3 million in 2014 and $14.3 million in 2013.

Financial Statement Impact

We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIEs described above.

As of December 31,	2015	2014
	(In Thousands)	
Assets		
Property, plant and equipment of variable interest entities, net	$268,239	$278,573
Regulatory assets[(a)]	9,088	7,882
Liabilities:		
Current maturities of long-term debt of variable interest entities	$ 28,309	$ 27,933
Accrued interest[(b)]	2,457	2,961
Long-term debt of variable interest entities, net	138,097	166,565

[(a)] *Included in long-term regulatory assets on our consolidated balance sheets.*
[(b)] *Included in accrued interest on our consolidated balance sheets.*

All of the liabilities noted in the table above relate to the purchase of the property, plant and equipment. The assets of the VIEs can be used only to settle obligations of the VIEs and the VIEs' debt holders have no recourse to our general credit. We have not provided financial or other support to the VIEs and are not required to provide such support. We did not record any gain or loss upon initial consolidation of the VIEs.

18. LEASES

Operating Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment. In determining lease expense, we recognize the effects of scheduled rent increases on a straight-line basis over the minimum lease term.

Rental expense and estimated future commitments under operating leases are as follows.

Year Ended December 31,	Total Operating Leases
	(In Thousands)
Rental expense:	
2013	$ 16,484
2014	14,143
2015	14,035
Future commitments:	
2016	$ 13,550
2017	11,646
2018	10,216
2019	8,815
2020	5,988
Thereafter	8,917
Total future commitments	$ 59,132

Capital Leases

We identify capital leases based on defined criteria. For both vehicles and computer equipment, new leases are signed each month based on the terms of master lease agreements.

Assets recorded under capital leases are listed below.

As of December 31,	2015	2014
	(In Thousands)	
Vehicles	$ 17,345	$ 18,820
Computer equipment	1,204	1,504
Generation plant	40,048	40,048
Accumulated amortization	(13,477)	(11,741)
Total capital leases	$ 45,120	$ 48,631

Capital leases are treated as operating leases for rate making purposes. Minimum annual rental payments, excluding administrative costs such as property taxes, insurance and maintenance, under capital leases are listed below.

Year Ended December 31,	Total Capital Leases
	(In Thousands)
2016	$ 5,812
2017	5,386
2018	5,233
2019	4,645
2020	4,007
Thereafter	56,050
	81,133
Amounts representing imputed interest	(32,271)
Present value of net minimum lease payments under capital leases	48,862
Less: Current portion	3,815
Total long-term obligation under capital leases	$ 45,047

19. QUARTERLY RESULTS (UNAUDITED)

Our business is seasonal in nature and, in our opinion, comparisons between the quarters of a year do not give a true indication of overall trends and changes in operations.

2015	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues[(a)]	$ 590,807	$ 589,563	$ 732,829	$ 545,965
Net income[(a)]	53,163	66,243	140,564	41,826
Net income attributable to Westar Energy, Inc.[(a)]	50,980	63,710	138,003	39,235
Per Share Data[(a)]:				
Basic:				
Earnings available	$ 0.38	$ 0.47	$ 0.97	$ 0.28
Diluted:				
Earnings available	$ 0.38	$ 0.46	$ 0.97	$ 0.28
Cash dividend declared per common share	$ 0.36	$ 0.36	$ 0.36	$ 0.36
Market price per common share:				
High	$ 44.03	$ 39.65	$ 40.22	$ 43.56
Low	$ 36.58	$ 33.88	$ 34.17	$ 37.55

[(a)] *Items are computed independently for each of the periods presented and the sum of the quarterly amounts may not equal the total for the year.*

2014	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues[(a)]	$ 628,556	$ 612,668	$ 764,040	$ 596,439
Net income[(a)]	70,970	55,822	149,760	45,773
Net income attributable to Westar Energy, Inc.[(a)]	68,955	53,473	147,382	43,449
Per Share Data[(a)]:				
Basic:				
Earnings available	$ 0.53	$ 0.41	$ 1.13	$ 0.33
Diluted:				
Earnings available	$ 0.52	$ 0.40	$ 1.10	$ 0.32
Cash dividend declared per common share	$ 0.35	$ 0.35	$ 0.35	$ 0.35
Market price per common share:				
High	$ 35.33	$ 38.24	$ 38.23	$ 43.15
Low	$ 31.67	$ 34.51	$ 33.76	$ 33.73

[(a)] *Items are computed independently for each of the periods presented and the sum of the quarterly amounts may not equal the total for the year.*

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

We maintain a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that we file or submit under the Securities Exchange Act of 1934, as amended (Exchange Act), is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in reports under the Exchange Act is accumulated and communicated to management, including the chief executive officer and the chief financial officer, allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of management, including the chief executive officer and the chief financial officer, of the effectiveness of our disclosure controls and procedures, the chief executive officer and the chief financial officer have concluded that our disclosure controls and procedures were effective.

There were no changes in our internal control over financial reporting during the three months ended December 31, 2015, that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

See "Item 8. Financial Statements and Supplementary Data" for Management's Report On Internal Control Over Financial Reporting and the Independent Registered Public Accounting Firm's report with respect to the effectiveness of internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Investors should note that we announce material financial information in SEC filings, press releases and public conference calls. In accordance with SEC guidance, we may also use the Investor Relations section of our website (http://www.WestarEnergy.com, under "Investors") to communicate with investors about our company. It is possible that the financial and other information we post there could be deemed to be material information. The information on our website is not part of this document.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information concerning directors required by Item 401 of Regulation S-K will be included under the caption *Election of Directors* in our definitive Proxy Statement for our 2016 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (2016 Proxy Statement), and that information is incorporated by reference in this Form 10-K. Information concerning executive officers required by Item 401 of Regulation S-K is located under Part I, Item 1 of this Form 10-K. The information required by Item 405 of Regulation S-K concerning compliance with Section 16(a) of the Exchange Act will be included under the caption *Additional Information — Section 16(a) Beneficial Ownership Reporting Compliance* in our 2016 Proxy Statement, and that information is incorporated by reference in this Form 10-K. The information required by Item 406, 407(c)(3), (d)(4) and (d)(5) of Regulation S-K will be included under the captions *Election of Directors — Corporate Governance Matters* and — *Board Meetings and Committees of the Board of Directors* in our 2016 Proxy Statement, and that information is incorporated by reference in this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 will be set forth in our 2016 Proxy Statement under the captions *Compensation Discussion and Analysis, Compensation Committee Report, Compensation of Executive Officers, Director Compensation* and *Compensation Committee Interlocks and Insider Participation,* and that information is incorporated by reference in this Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 will be set forth in our 2016 Proxy Statement under the captions *Beneficial Ownership of Voting Securities* and *Equity Compensation Plan Information,* and that information is incorporated by reference in this Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by Item 13 will be set forth in our 2016 Proxy Statement under the caption *Election of Directors — Corporate Governance Matters,* and that information is incorporated by reference in this Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by Item 14 will be set forth in our 2016 Proxy Statement under the caption of *Ratification and Confirmation of Deloitte and Touche LLP as Our Independent Registered Public Accounting Firm for 2016* and its subsections captioned *Independent Registered Accounting Firm Fees and Audit Committee Pre-Approval Policies and Procedures,* and that information is incorporated by reference in this Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

FINANCIAL STATEMENTS INCLUDED HEREIN

Westar Energy, Inc.

Management's Report on Internal Control Over Financial Reporting
Reports of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2015 and 2014
Consolidated Statements of Income for the years ended December 31, 2015, 2014 and 2013
Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013
Consolidated Statements of Changes in Equity for the years ended December 31, 2015, 2014 and 2013
Notes to Consolidated Financial Statements

SCHEDULES

Schedule II — Valuation and Qualifying Accounts

Schedules omitted as not applicable or not required under the Rules of Regulation S-X: I, III, IV and V.

EXHIBIT INDEX

All exhibits marked "I" are incorporated herein by reference. All exhibits marked with "*" are management contracts or compensatory plans or arrangements required to be identified by Item 15(a)(3) of Form 10-K. All exhibits marked "#" are filed with this Form 10-K.

	Description	
1(a)	Sales Agency Financing Agreement, dated March 21, 2013, with BNY Mellon Capital Markets, LLC and The Bank of New York Mellon (filed as Exhibit 1.1 to the Form 8-K filed on March 22, 2013)	I
3(a)	By-laws of Westar Energy, Inc., as amended April 28, 2004 (filed as Exhibit 3(a) to the Form 10-Q for the period ended June 30, 2004 filed on August 4, 2004)	I
3(b)	Restated Articles of Incorporation of Westar Energy, Inc., as amended through May 25, 1988 (filed as Exhibit 4 to the Form S-8 Registration Statement, SEC File No. 33-23022 filed on July 15, 1988)	I
3(c)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-K405 for the period ended December 31, 1998 filed on April 14, 1999)	I
3(d)	Certificate of Correction to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(b) to the Form 10-K for the period ended December 31, 1991 filed on March 30, 1992)	I
3(e)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(c) to the Form 10-K for the period ended December 31, 1994 filed on March 30, 1995)	I
3(f)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-Q for the period ended June 30, 1994 filed on August 11, 1994)	I
3(g)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(a) to the Form 10-Q for the period ended June 30, 1996 filed on August 14, 1996)	I
3(h)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-Q for the period ended March 31, 1998 filed on May 12, 1998)	I
3(i)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(l) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003)	I
3(j)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(m) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003)	I
3(k)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(m) to the Form S-3 Registration Statement No. 333-125828 filed on June 15, 2005)	I

3(l)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(m) to the Form 10-K for the period ended December 31, 2011 filed on February 23, 2012)	I
4(a)	Mortgage and Deed of Trust dated July 1, 1939 between Westar Energy, Inc. and Harris Trust and Savings Bank, Trustee (filed as Exhibit 4(a) to Registration Statement No. 33-21739)	I
4(b)	First and Second Supplemental Indentures dated July 1, 1939 and April 1, 1949, respectively (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(c)	Sixth Supplemental Indenture dated October 4, 1951 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(d)	Fourteenth Supplemental Indenture dated May 1, 1976 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(e)	Twenty-Eighth Supplemental Indenture dated July 1, 1992 (filed as Exhibit 4(o) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(f)	Twenty-Ninth Supplemental Indenture dated August 20, 1992 (filed as Exhibit 4(p) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(g)	Thirtieth Supplemental Indenture dated February 1, 1993 (filed as Exhibit 4(q) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(h)	Thirty-First Supplemental Indenture dated April 15, 1993 (filed as Exhibit 4(r) to the Form S-3 Registration Statement No. 33-50069 filed on August 24, 1993)	I
4(i)	Thirty-Second Supplemental Indenture dated April 15, 1994 (filed as Exhibit 4(s) to the Form 10-K for the period ended December 31, 1994 filed on March 30, 1995)	I
4(j)	Senior Indenture dated August 1, 1998 (filed as Exhibit 4.1 to the Form 10-Q for the period ended June 30, 1998 filed on August 12, 1998)	I
4(k)	Form of Senior Note (included in Exhibit 4(j))	I
4(l)	Thirty-Fourth Supplemental Indenture dated June 28, 2000 (filed as Exhibit 4(v) to the Form 10-K for the period ended December 31, 2000 filed on April 2, 2001)	I
4(m)	Thirty-Fifth Supplemental Indenture dated May 10, 2002 between Westar Energy, Inc. and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4.1 to the Form 10-Q for the period ended March 31, 2002 filed on May 15, 2002)	I
4(n)	Thirty-Sixth Supplemental Indenture dated as of June 1, 2004, between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank), to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.1 to the Form 8-K filed on January 18, 2005)	I
4(o)	Thirty-Seventh Supplemental Indenture, dated as of June 17, 2004, between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank), to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.2 to the Form 8-K filed on January 18, 2005)	I
4(p)	Thirty-Eighth Supplemental Indenture, dated as of January 18, 2005, between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank), to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.3 to the Form 8-K filed on January 18, 2005)	I
4(q)	Thirty-Ninth Supplemental Indenture dated June 30, 2005 between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank) to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.1 to the Form 8-K filed on July 1, 2005)	I
4(r)	Form of Forty-Second Supplemental Indenture, dated as of March 1, 2012 by and among Westar Energy, Inc., The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4.1 to the Form 8-K filed on February 29, 2012)	I
4(s)	Form of Forty-Second Supplemental (Reopening) Indenture, dated as of May 17, 2012 by and among Westar Energy, Inc., The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4.1 to the Form 8-K filed on May 16, 2012)	I
4(t)	Form of Forty-Third Supplemental Indenture, dated as of March 28, 2013, by and among Westar Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as successor trustee to Harris Trust and Savings Bank (filed as Exhibit 4.1 to the Form 8-K filed on March 22, 2013)	I

4(u)	Form of Forty-Fourth Supplemental Indenture, dated as of August 19, 2013, by and among Westar Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as successor trustee to Harris Trust and Savings Bank (filed as Exhibit 4.1 to the Form 8-K filed on August 14, 2013)	I
4(v)	Form of Forty-Fifth Supplemental Indenture, dated as of November 13, 2015, by and among Westar Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as successor to Harris Trust and Savings Bank (filed as Exhibit 4.1 to the Form 8-K filed on November 6, 2015)	I
	Instruments defining the rights of holders of other long-term debt not required to be filed as Exhibits will be furnished to the Commission upon request.	
10(a)	Executive Salary Continuation Plan of Western Resources, Inc., as revised, effective September 22, 1995 (filed as Exhibit 10(j) to the Form 10-K for the period ended December 31, 1995 filed on March 27, 1996)*	I
10(b)	Amended and Restated Long-Term Incentive and Share Award Plan (filed as Exhibit 10 to the Form 8-K filed on May 6, 2011)*	I
10(c)	Westar Energy, Inc. Form of Restricted Share Units Award (filed as Exhibit 10(f) to the Form 10-K for the period ended December 31, 2014 filed on February 25, 2015)*	I
10(d)	Westar Energy, Inc. Form of Performance Based Restricted Share Units Award (filed as Exhibit 10(g) to the Form 10-K for the period ended December 31, 2014 filed on February 25, 2015)*	I
10(e)	Westar Energy, Inc. Non-Employee Director Deferred Compensation Plan, as amended and restated, dated as of October 20, 2004 (filed as Exhibit 10.1 to the Form 8-K filed on October 21, 2004)*	I
10(f)	Summary of Westar Energy, Inc. Non-Employee Director Compensation*	#
10(g)	Form of Amended and Restated Change in Control Agreement with Officers of Westar Energy, Inc.*	#
10(h)	Westar Energy, Inc. Retirement Benefit Restoration Plan (filed as Exhibit 10.1 to the Form 8-K filed on April 2, 2010)*	I
10(i)	Westar Energy, Inc. 401(k) Benefit Restoration Plan (filed as Exhibit 10(l) to the Form 10-K for the period ended December 31, 2014 filed on February 25, 2015)*	I
10(j)	Credit Agreement dated as of February 18, 2011, among Westar Energy, Inc. and several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10.1 to the Form 8-K filed on February 22, 2011)	I
10(k)	First Extension Agreement dated as of February 12, 2013, among Westar Energy, Inc. and several banks and other financial institutions party thereto (filed as Exhibit 10.1 to the Form 8-K filed on February 15, 2013)	I
10(l)	Second Extension Agreement dated as of February 14, 2014, among Westar Energy, Inc. and several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10(v) to the Form 10-K for the period ended December 31, 2013 filed on February 26, 2014)	I
10(m)	Fourth Amended and Restated Credit Agreement dated as of September 29, 2011, among Westar Energy, Inc. and several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10.1 to the Form 8-K filed on September 29, 2011)	I
10(n)	First Extension Agreement dated as of July 19, 2013, among Westar Energy, Inc. and several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10(a) to the Form 10-Q for the period ended September 30, 2014 filed on November 5, 2014)	I

10(o)	Second Extension Agreement dated as of September 18, 2014, among Westar Energy, Inc. and several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10(b) to the Form 10-Q for the period ended September 30, 2014 filed on November 5, 2014)	I
10(p)	Third Extension Agreement dated as of September 17, 2015, among Westar Energy, Inc. and several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10 to the Form 10-Q for the period ended September 30, 2015 filed on November 3, 2015)	I
10(q)	Master Confirmation for Forward Stock Sale Transactions, dated March 21, 2013, between Westar Energy, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Form 8-K filed on March 22, 2013)	I
10(r)	Confirmation of Forward Sale Transaction, dated September 24, 2013, between JPMorgan Chase Bank, National Association, London Branch and Westar Energy, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on September 27, 2013)	I
10(s)	Confirmation of Forward Sale Transaction, dated September 24, 2013, between Wells Fargo Bank, National Association and Westar Energy, Inc. (filed as Exhibit 10.2 to the Form 8-K filed on September 27, 2013)	I
10(t)	Confirmation of Additional Forward Stock Sale Transaction, dated October 16, 2013, between JPMorgan Chase Bank, National Association, London Branch and Westar Energy, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on October 17, 2013)	I
10(u)	Confirmation of Additional Forward Stock Sale Transaction, dated October 16, 2013, between Wells Fargo Bank, National Association and Westar Energy, Inc. (filed as Exhibit 10.2 to the Form 8-K filed on October 17, 2013)	I
12	Computations of Ratio of Consolidated Earnings to Fixed Charges	#
21	Subsidiaries of the Registrant	#
23	Consent of Independent Registered Public Accounting Firm, Deloitte & Touche LLP	#
31(a)	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	#
31(b)	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	#
32	Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished and not to be considered filed as part of the Form 10-K)	#
101.INS	XBRL Instance Document	#
101.SCH	XBRL Taxonomy Extension Schema Document	#
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	#
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	#
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	#
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	#

WESTAR ENERGY, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions[a]	Balance at End of Period
		(In Thousands)		
Year ended December 31, 2013				
Allowances deducted from assets for doubtful accounts	$4,916	$7,039	$(7,359)	$4,596
Year ended December 31, 2014				
Allowances deducted from assets for doubtful accounts	$4,596	$9,752	$(9,039)	$5,309
Year ended December 31, 2015				
Allowances deducted from assets for doubtful accounts	$5,309	$8,614	$(8,629)	$5,294

[a] *Result from write-offs of accounts receivable.*

SIGNATURE

Pursuant to the requirements of Sections 13 or 15(d) 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

WESTAR ENERGY, INC.

Date: February 24, 2016 By: /s/ ANTHONY D. SOMMA

Anthony D. Somma
Senior Vice President, Chief Financial Officer and Treasurer

SIGNATURES

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.

Signature	Title	Date
/s/ MARK A. RUELLE (Mark A. Ruelle)	Director, President and Chief Executive Officer (Principal Executive Officer)	February 24, 2016
/s/ ANTHONY D. SOMMA (Anthony D. Somma)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	February 24, 2016
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 24, 2016
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 24, 2016
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 24, 2016
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 24, 2016
/s/ RICHARD L. HAWLEY (Richard L. Hawley)	Director	February 24, 2016
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 24, 2016
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 24, 2016
/s/ S. CARL SODERSTROM JR. (S. Carl Soderstrom Jr.)	Director	February 24, 2016

SHAREHOLDER INFORMATION AND ASSISTANCE

Westar Energy's transfer agent, Continental Stock Transfer and Trust Company, provides our registered shareholders information and assistance regarding:

- Dividend payments
  - Historically paid on the first business day of January, April, July and October
- Direct deposit of dividends
- Transfer of shares
- Lost stock certificate assistance
- Direct Registration (DRS) eligible
- Direct Stock Purchase Plan assistance
  - Dividend reinvestment
  - Purchase additional shares by making optional cash payments by check or monthly electronic withdrawal from your bank account
  - Deposit your stock certificates into the plan for safekeeping
  - Sell shares

Please contact Continental Stock Transfer and Trust Company in writing to request elimination of duplicate mailings because of stock registered in more than one way. Mailing of annual reports can be eliminated by marking your proxy card to consent to accessing reports electronically on the Internet.

Registered shareholders can easily access their shareholder account information online at **http://www.continentalstock.com,** then click **Shareholder Log In** located in the upper area of the screen.

CONTACTING CONTINENTAL STOCK TRANSFER AND TRUST COMPANY

TELEPHONE

Toll-free:	800-527-2495
Fax:	212-616-7612

Service Representatives are available from 8:30 am to 5:30 pm Eastern Time Monday through Friday.

ADDRESS

Westar Energy, Inc.
c/o Continental Stock Transfer and Trust Company
17 Battery Pl, 8th Floor
New York, NY 10004

E-MAIL ADDRESS

cstmail@continentalstock.com

Please include a daytime telephone number in all correspondence.

CONTACTING INVESTOR RELATIONS

TELEPHONE 785-575-8227

ADDRESS

Westar Energy, Inc.
Investor Relations
P.O. Box 889
Topeka, KS 66601-0889

E-MAIL ADDRESS

ir@WestarEnergy.com

Copies of our Annual Report on Form 10-K filed with the Securities and Exchange Commission and other published reports can be obtained without charge by contacting Investor Relations at the above address, by accessing the company's home page on the Internet at **WestarEnergy.com** or by accessing the Securities and Exchange Commission's Internet website at **sec.gov.**

TRUSTEE FOR FIRST MORTGAGE BONDS

PRINCIPAL TRUSTEE, PAYING AGENT AND REGISTRAR

The Bank of New York
Mellon Trust Co.
2 North LaSalle Street, Suite 1020
Chicago, IL 60602-3802
800-254-2826

CORPORATE INFORMATION

CORPORATE ADDRESS

Westar Energy, Inc.
818 South Kansas Avenue
Topeka, KS 66612-1203
785-575-6300
WestarEnergy.com

COMMON STOCK LISTING

Ticker Symbol (NYSE): WR

Daily Stock Table Listing:
WestarEngy

CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER CERTIFICATIONS

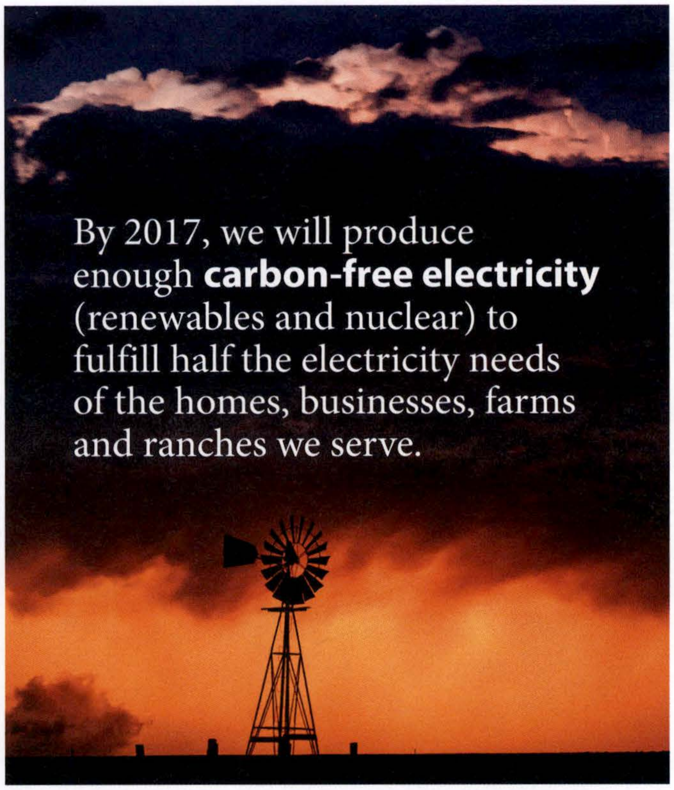
In 2016, our chief executive officer submitted a certificate to the New York Stock Exchange (NYSE) affirming that he is not aware of any violation by the company of the NYSE's corporate governance listing standards. Our chief executive officer's and chief financial officer's certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 for the year ended December 31, 2015, were included as exhibits to Westar Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2015, that was filed with the Securities and Exchange Commission.

Westar Energy

2015
Moving Kansas Forward

At Westar, we take to heart the interests of our customers, employees, investors and the communities we serve. We demonstrate our commitment with our environmental leadership, people, strong communities, safety and investment.

At Westar, we're leading the way in providing responsible, clean energy. We have a commonsense approach to develop green energy while keeping our electricity cost-effective and reliable.



Environmental improvements we've made since 2005

↓ **93%** reduction in sulfur dioxide

↓ **81%** reduction in nitrogen oxide

↓ **27%** reduction of CO_2 emissions. By 2017 that drops further to 36%

$1.8 BILLION invested in environmental improvements, including the construction of our award-winning wetlands project at our **Jeffrey Energy Center**.

Water efficiency

Annually, we recycle **60 million gallons of water** at our Jeffrey Energy Center. Conservation efforts the past few years have saved nearly 800 million gallons of water annually. That's enough to fill more than 1,000 Olympic-sized swimming pools.

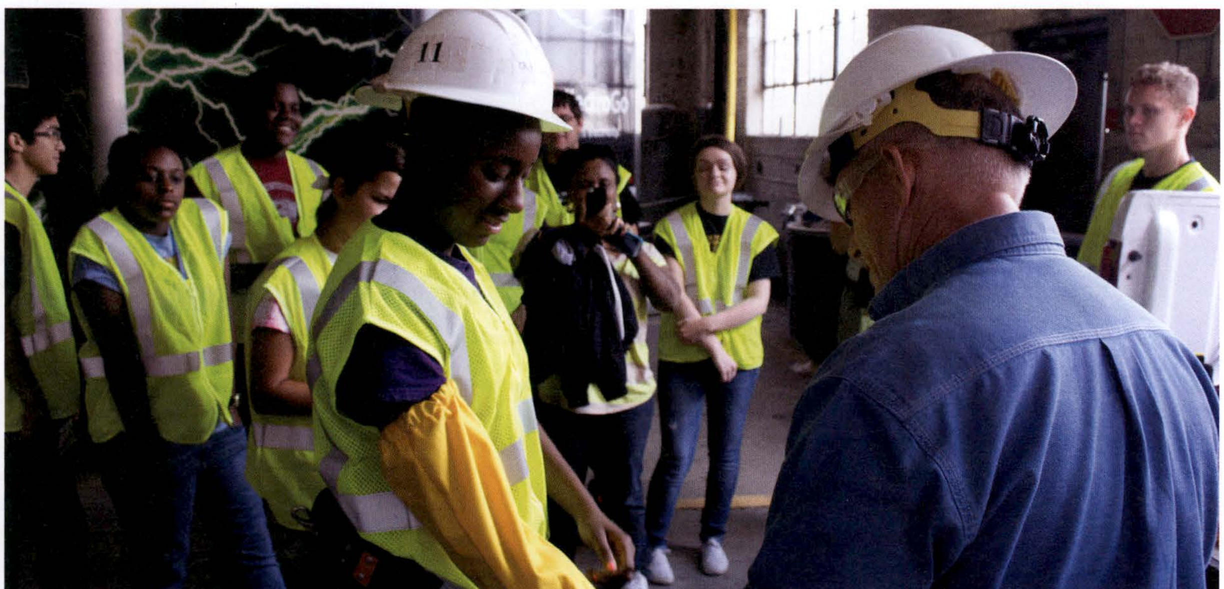
$50 MILLION efficiency improvements to our coal plants with **$50 million more planned**.

3,000 VOLUNTEER HOURS worked by Westar's Green Team in 2015 on **more than 70 projects** to restore native species, protect threatened wildlife and improve recreation and nature opportunities.

PEOPLE

Growing our own. Westar Energy partners with Kansas high schools to provide students with hands-on job shadowing experiences through our Electrify Your Future program. In 2015, 240 students participated in this program.

Our award-winning internship program is recognized nationally for providing the best intern experience in the energy industry.

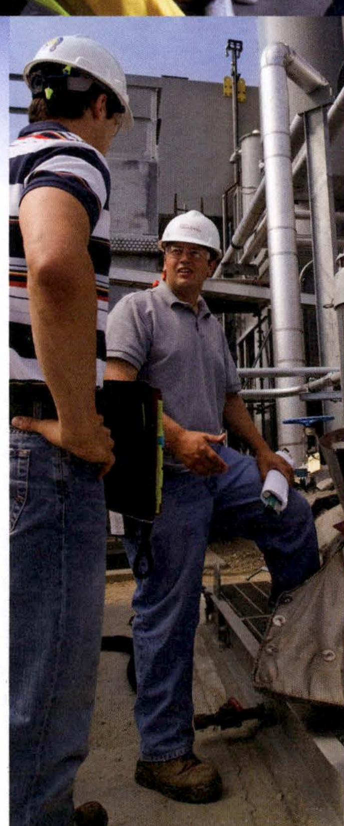


Diversity

We want to draw talent from every community we have the privilege of serving. Through proactive recruiting and outreach, we're working to fully engage a diverse workforce where differences are welcomed, valued and appreciated for the strength they add to our organization.

We value diversity among our suppliers and appreciate the value multiple perspectives bring to our company.

Westar encourages minority and women-owned businesses to register as potential suppliers at **WestarEnergy.com**.



Ethics

Integrity and accountability are two of our core values.

We respect each other and those we serve by choosing the hard right over the easy wrong. We take personal responsibility for our actions, decisions and commitments.

Our **Integrity Hotline** provides employees, vendors and others an avenue to raise concerns, report suspected dishonest or improper conduct and take initiative to maintain the ethical culture at the heart of our business. Call (877) 248-1184.

STRONG COMMUNITIES

Westar Foundation. Since 1990, the Westar Energy Foundation has awarded more than $20 million to civic and charitable organizations. In 2015 alone, the Foundation granted $2 million to 250 non-profit organizations.

2,000
households received
$350,000
in emergency assistance last year through Project Deserve.

INVESTMENT

60%
of our employees participated in the Your Gift, Your Choice employee giving campaign, which raised
$500,000
for 90 nonprofit organizations throughout Kansas.

More than
300 EMPLOYEES
logged 18,000 volunteer hours, serving 200 community groups.

HUNDREDS
of employees mentoring kids through Big Brothers Big Sisters, Girl Scouts and other youth groups.

SAFETY

Public Safety

We're proud of our public safety partnerships designed to help keep our neighbors safe around electricity. We work with contractors, farmers and ranchers, schools, first responders and emergency management professionals to increase public awareness of safety around power lines and equipment.

Employee Safety

Employee safety remains a constant focus, with our safety performance ranking in the top quartile of companies. We maintain a culture of helping each other go home safely to our families at the end of each day. We expect Zero Unsafe Acts and rely on employees to keep safety at the forefront of all activities.

Cybersecurity

In 2015, Westar Energy participated in the North American Electric Reliability Corporation GridEx security exercise along with more than 4,000 participants. The exercise allowed us to test and retest our plans to defend the electrical system against a broad array of cyber and physical threats.

Plugged In: Westar's Community Impact

ECONOMIC IMPACT

$1.1 BILLION
2016
planned capital investment in Kansas

2,300 EMPLOYEES
1,600 RETIREES

$189 MILLION
Annual payroll

$300 MILLION
2015 taxes
Sales & use tax, property tax, franchise fees paid to cities

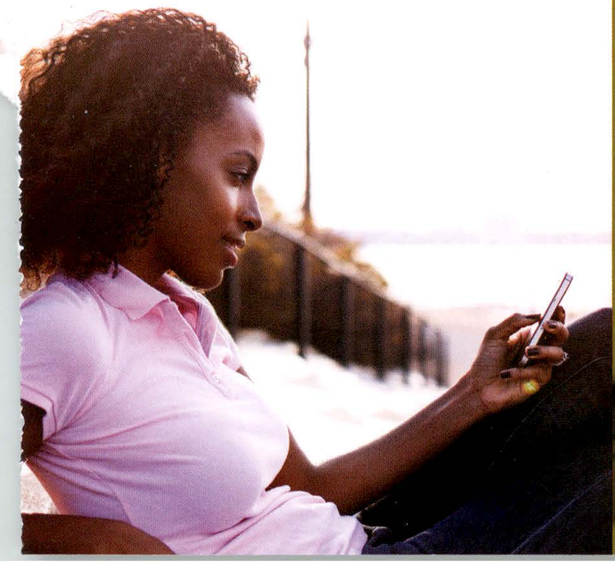
CUSTOMER RELATIONSHIPS

610,000
Residential customers

85,000
Commercial customers

5,000
Industrial customers

- **3.2 million contacts** annually to our Wichita-based call center
- **Outage map** at WestarEnergy.com provides neighborhood-specific outage information
- **Free mobile app launched** for easier access to information
- **Digital meters** improve service and communication



COMMUNITY INVOLVEMENT

$2 MILLION Westar Foundation philanthropic support in 2015

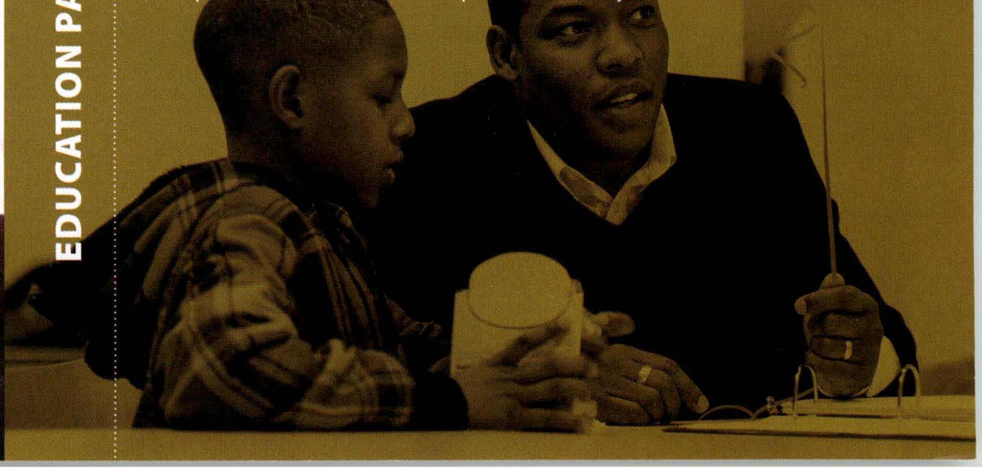
$500,000
Your Gift/Your Choice employee gifts in 2015

150 EMPLOYEES
serve on nearly **200 civic and charitable boards** in our communities

18,000 VOLUNTEER HOURS
logged by Westar employees in 2015

EDUCATION PARTNERSHIPS

- **STEM (Science, Technology, Engineering, Math) initiatives** to promote workforce development in emerging fields
- Higher education partnerships with Emporia State University, Haskell Indian Nations University, Kansas State University, Pittsburg State University, Washburn University, Wichita State University and the University of Kansas
- Electrify Your Future programs that work directly with kids to promote workforce development in STEM jobs



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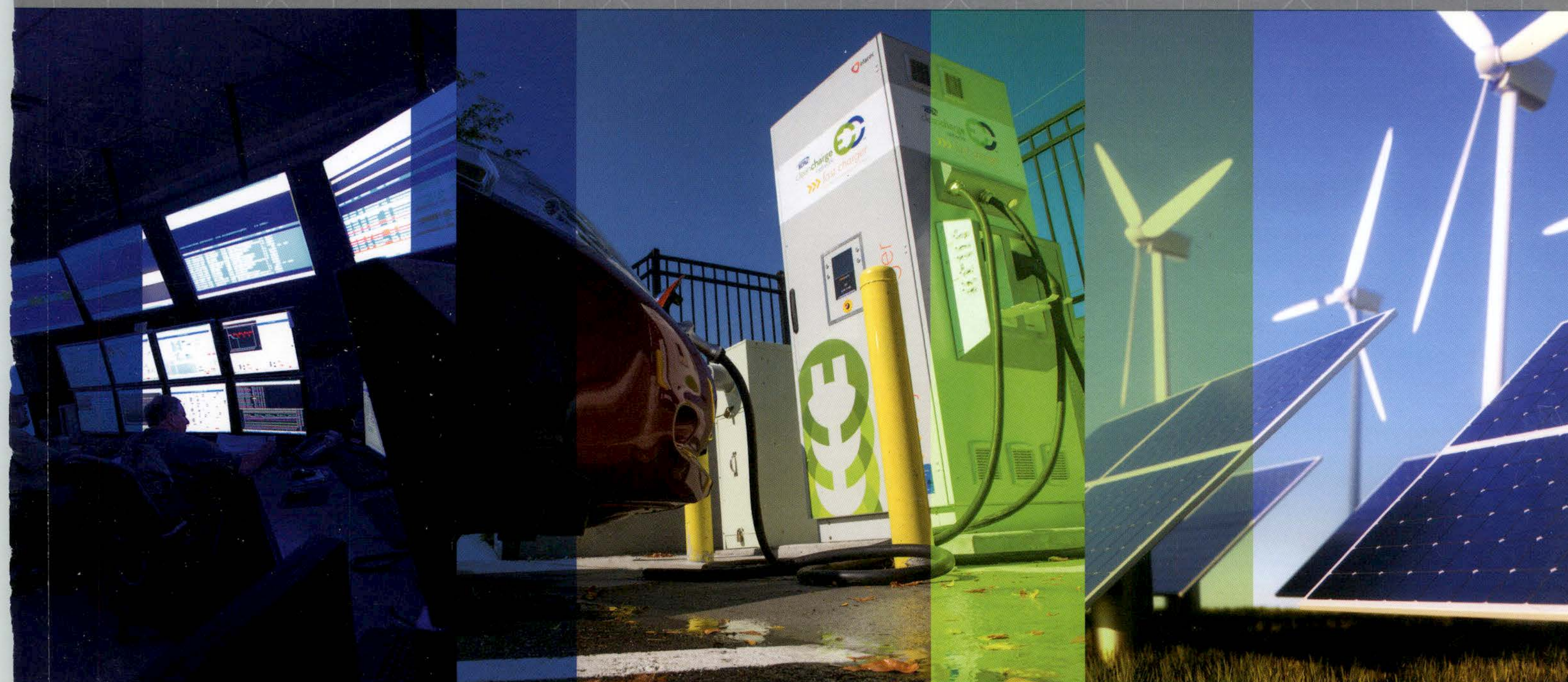
OUR FUTURE FOCUS

COMMITMENT. INNOVATION. RESULTS.



2015 ANNUAL REPORT

GREAT PLAINS ENERGY

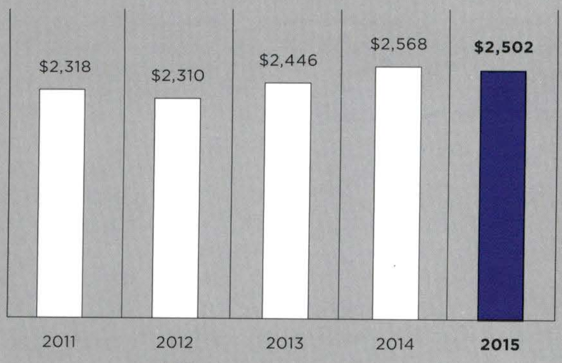
SELECTED FINANCIAL DATA

Year Ended December 31	2015	2014	2013	2012	2011
(Dollars in millions except per share amounts)					
GREAT PLAINS ENERGY					
Operating revenues	**$ 2,502**	$ 2,568	$ 2,446	$ 2,310	$ 2,318
Net income attributable to Great Plains Energy	**$ 213**	$ 243	$ 250	$ 200	$ 174
Basic earnings per common share	**$ 1.37**	$ 1.57	$ 1.62	$ 1.36	$ 1.27
Diluted earnings per common share	**$ 1.37**	$ 1.57	$ 1.62	$ 1.35	$ 1.25
Total assets at year end [a]	**$ 10,739**	$ 10,453	$ 9,770	$ 9,626	$ 9,096
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities) [a]	**$ 3,746**	$ 3,481	$ 3,492	$ 2,999	$ 3,522
Cash dividends per common share	**$ 0.9975**	$ 0.935	$ 0.8825	$ 0.855	$ 0.835
SEC ratio of earnings to fixed charges	**2.58**	2.72	2.75	2.31	2.03
KCP&L					
Operating revenues	**$ 1,714**	$ 1,731	$ 1,671	$ 1,580	$ 1,558
Net income	**$ 153**	$ 162	$ 169	$ 142	$ 136
Total assets at year end [a]	**$ 7,815**	$ 7,495	$ 6,821	$ 6,689	$ 6,276
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities) [a]	**$ 2,563**	$ 2,297	$ 2,294	$ 1,887	$ 1,899
SEC ratio of earnings to fixed charges	**2.57**	2.69	2.76	2.58	2.52

[a] Adjusted for adoption of Accounting Standard Update (ASU) No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs*

GREAT PLAINS ENERGY OPERATING REVENUES

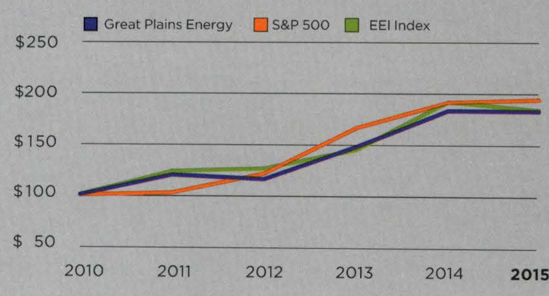
(Dollars in millions)



STOCK PERFORMANCE GRAPH

(Dollars)

Comparison of Cumulative Total Returns* of Great Plains Energy, S&P 500 Index and EEI Index



**Total Return assumes reinvestment of dividends. Assumes $100, invested on December 31, 2010, in Great Plains Energy common stock, S&P 500 Index and EEI Index*

AS A LEADING PROVIDER OF ELECTRICITY IN THE MIDWEST, WE FOCUS ON CLOSELY MANAGING OUR EXISTING BUSINESS, PROMOTING ECONOMIC GROWTH AND IMPROVING OUR CUSTOMER EXPERIENCE.

TO OUR SHAREHOLDERS

2015 was a landmark year for our city, our company and our industry. I'm not just talking about Sporting KC winning the Major League Soccer Championship in 2013, the Kansas City Royals' back-to-back World Series runs leading to a World Series Championship in 2015, or even the Kansas City Chiefs' winning season and playoff victory in 2016.

Although our community is extremely proud and excited by these hard earned accomplishments, even more is happening in Kansas City. Our City is quickly building a reputation as an innovative, sustainable place to live and work and is attracting businesses and talent to our area. The Kansas City region is now the number two manufacturer of automobiles in America, second only to Detroit. With billion-dollar expansions underway at the manufacturing plants of both Ford and General Motors, vehicle production and supplier growth in Kansas City are at an all-time high. In addition to automotive manufacturing growth, Cerner Corporation, a healthcare information technology company, has been a success story for several years. Cerner is building a new $4.5 billion campus in Kansas City and expects to create up to 16,000 new jobs over the next decade, making it the largest economic development project in Missouri history. These are just a few examples of the exciting growth happening in the region we serve.

Employment growth in the region has contributed to an improving residential real estate and job market, resulting in continuing customer growth. In 2015, demand for electricity was up for the third consecutive year. While we view these demand trends positively, we are facing a new-normal for our industry - flat to low growth in electricity demand. Despite continued customer growth, we expect to continue to see a decline in the amount of electricity the average customer uses.

Changing Industry Dynamic

There's no question that the electric utility industry is entering a time of redefinition and change. Today is the beginning of a new era in grid modernization and a fundamental shift where customers and technology will push the limits of our historical business and regulatory models.

For more than a century, investor-owned electric utilities that plan, build and run the distribution grid have operated under a straightforward regulated

Our Clean Charge Network

When complete, the Clean Charge Network will have more than 1,000 charging stations in our service area. This has made Kansas City one of the best places to own and operate an electric vehicle.

COMMITMENT

KCP&L proudly serves our communities through charitable giving and employee volunteerism, to ensure our customers have the resources and support needed now and well into the future.

monopoly system. This model is predicated on reliability and cost efficiency. And it has worked well. The pricing model is simple: Investment plus cost of operations divided by customer usage. Investors understand it. The result? One of the most reliable infrastructure systems in world history.

Now, the system is evolving and future success will be defined differently. Demand for electricity has softened, we are seeing increased adoption of distributed generation and customers expect much more than just affordable and reliable electricity. To be successful in this new paradigm, our business and regulatory models must transition to meet these expectations.

Over the past ten years, Great Plains Energy has been engaged in a comprehensive energy plan build out of new generation sources, transmission and distribution system upgrades, and environmental plant retrofits to reduce emissions and comply with environmental mandates. Meeting each of these goals serves to position us to meet these changing customer dynamics. As we emerge from the capital-intense focus of the last decade, we believe we are well positioned to face these industry challenges.

2015 Results

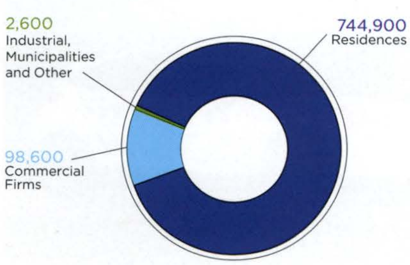
The last piece of our Comprehensive Energy Plan was the $1.2 billion environmental retrofit of our La Cygne Generation Station. This is a 1,398 megawatt coal-fired station made up of two units jointly owned by KCP&L and Westar. In 2015, we completed rate cases in Kansas and Missouri and received fair orders with no disallowance on the La Cygne project costs. As we look ahead, Great Plains Energy plans to continue providing its customers with Tier 1 service and stable returns for its shareholders. The

TRANSOURCE

Our Transource Energy joint venture has projects completed or underway in Missouri and West Virginia and continues to remain well positioned to provide long-term earnings growth in the competitive transmission market.

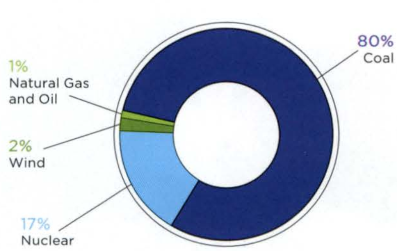
Stable Regulated Customer Base

Number of Customers by Segment (Year-end 2015)

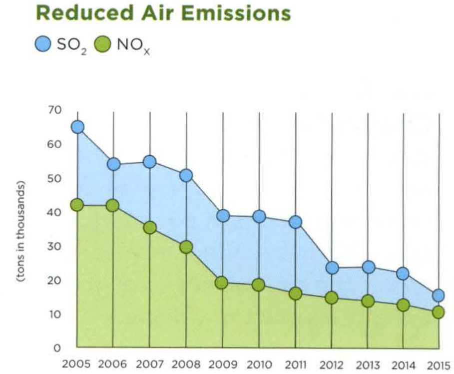


Generation Mix

Net MWhs Generated by Fuel Type (2015)

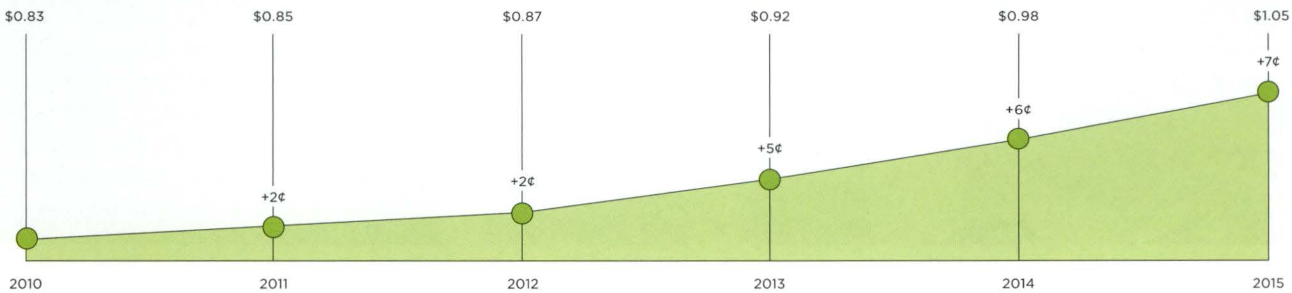


Reduced Air Emissions



Dividend Growth Chart

2010 - 2015 based on fourth quarter declared dividend



opportunity to generate cash available for investment, credit support and dividend growth is exciting. We are working with others in Missouri on energy legislation to reform our century old regulatory model to meet the needs of all stakeholders. We will continue to be disciplined in managing the business but absent legislative relief, we will be forced to file more frequent rate cases. The resulting credit profile and cash flow flexibility will allow us to maintain top-tier service through investment, maintain credit and grow the dividend.

We have increased our dividend for the fifth consecutive year, delivering total shareholder returns of 71 percent in that same timeframe. Our targeted future dividend growth profile of 5 to 7 percent, together with our annualized targeted earnings growth profile of 4 to 5 percent from 2016 to 2020, make us excited about our long-term opportunities for growth.

Our Future Focus

Future success means embracing big data, automation and interactivity, especially on the demand side, where customer-owned, edge-of-grid resources have made the distribution grid increasingly unpredictable. It also means adopting sustainability and energy efficiency practices like never before, not only because policy is dictating it, but because our customers are too. We have announced plans to cease burning coal by 2021 at three of our plants, totaling more than 700 MW, or nearly 20 percent, of our coal fleet. We believe these actions along with our plans to meet additional future resource needs with renewables, energy efficiency and gas generation are our best solutions to meet the future resource needs of our region.

We believe that - as a utility and as an industry - utilities are best positioned to mold the grid of

CEDAR POINT SAFETY AND TRAINING CENTER

Our Cedar Point Safety and Training Center is a testament to our commitment to safety. Centrally located in our service territory, it provides both indoor and outdoor apprentice skills training.

INNOVATION

KCP&L believes in providing clean, sustainable energy to our customers through energy efficiency, wind and solar energy initiatives. We now have the largest renewable energy portfolio in Missouri.

RESULTS

The robust management of our assets, continued investment in national transmission, a growing regional economy and our experience help us achieve a more efficient model that continually delivers affordable, reliable and clean energy to our customers.

the future in ways that capture the most value and benefit to all stakeholders. Unlike new entrants to the electric generation and distribution space, utilities do not optimize to one business model, solution or technology. Rather, we optimize in favor

RELIABILITY IS A KEY FOCUS

KCP&L makes life better for thousands every day by providing electric services in a sustainable way - affordable, reliable and clean.

of our obligation to serve all customers fairly and reliably. As such, we firmly believe that the utility is best suited to drive these changes to ensure the best societal outcomes in partnership with both our regulators and customers.

Part of our strategy focuses on testing and proving customer programs via targeted projects and technologies that align with the philosophy of empowering customers and optimizing the grid. By embracing a vision of the future that chooses to think of integrating edge-of-grid resources as an opportunity (instead of a threat), and customers as partners (instead of obstacles), we can optimize grid utilization and continue to deliver affordable, clean and reliable power for the long haul. Our ultimate goal? To demonstrate that electric utilities are best positioned to maximize the total value of the grid - from generation to consumption - and create the platform for implementing the grid of the future.

With flat, or even declining overall demand for electricity, the shutdown of aging fossil-fired resources and increased environmental pressures, we are now faced with the same optimization, automation and "lean" redesigns that most other industries have already been through.

While many new players will enter this space in the next several decades and our resource mix will likely change significantly, utilities will remain at the center and serve as the stewards of the grid. And that leads us to our final belief that strong partnerships with our customers will characterize this new future. With our communities and customers as our partners, and our employees as champions, we will be able to effectively engage the grid's edge and make this new future a reality.

TERRY BASSHAM

Chairman of the Board, President and Chief Executive Officer

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

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2015**

or

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

For the transition period from _______ to_______

Commission File Number	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices and telephone number	I.R.S. Employer Identification Number
001-32206	**GREAT PLAINS ENERGY INCORPORATED** (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	43-1916803
000-51873	**KANSAS CITY POWER & LIGHT COMPANY** (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	44-0308720

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is registered on the New York Stock Exchange:

Registrant	Title of each class	
Great Plains Energy Incorporated	Cumulative Preferred Stock par value $100 per share	3.80%
	Cumulative Preferred Stock par value $100 per share	4.50%
	Cumulative Preferred Stock par value $100 per share	4.35%
	Common Stock without par value	

Securities registered pursuant to Section 12(g) of the Act: Kansas City Power & Light Company Common Stock without par value.

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

Great Plains Energy Incorporated Yes X No _ Kansas City Power & Light Company 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 Act.

Great Plains Energy Incorporated Yes _ No X Kansas City Power & Light Company 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.

Great Plains Energy Incorporated Yes X No _ Kansas City Power & Light Company 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Great Plains Energy Incorporated Yes X No _ Kansas City Power & Light Company Yes X No _

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to the Form 10-K.

Great Plains Energy Incorporated X Kansas City Power & Light Company 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.

Great Plains Energy Incorporated	Large accelerated filer	X	Accelerated filer	_
	Non-accelerated filer	_	Smaller reporting company	_
Kansas City Power & Light Company	Large accelerated filer	_	Accelerated filer	_
	Non-accelerated filer	X	Smaller reporting company	_

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Great Plains Energy Incorporated Yes _ No X Kansas City Power & Light Company Yes _ No X

The aggregate market value of the voting and non-voting common equity held by non-affiliates of Great Plains Energy Incorporated (based on the closing price of its common stock on the New York Stock Exchange on June 30, 2015) was approximately $3,725,295,076. All of the common equity of Kansas City Power & Light Company is held by Great Plains Energy Incorporated, an affiliate of Kansas City Power & Light Company.

On February 23, 2016, Great Plains Energy Incorporated had 154,414,902 shares of common stock outstanding.

On February 23, 2016, Kansas City Power & Light Company had one share of common stock outstanding and held by Great Plains Energy Incorporated.

Kansas City Power & Light Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format.

Documents Incorporated by Reference

Portions of the 2016 annual meeting proxy statement of Great Plains Energy Incorporated to be filed with the Securities and Exchange Commission are incorporated by reference in Part III of this report.

TABLE OF CONTENTS

This combined annual report on Form 10-K is being filed by Great Plains Energy Incorporated (Great Plains Energy) and Kansas City Power & Light Company (KCP&L). KCP&L is a wholly owned subsidiary of Great Plains Energy and represents a significant portion of its assets, liabilities, revenues, expenses and operations. Thus, all information contained in this report relates to, and is filed by, Great Plains Energy. Information that is specifically identified in this report as relating solely to Great Plains Energy, such as its financial statements and all information relating to Great Plains Energy's other operations, businesses and subsidiaries, including KCP&L Greater Missouri Operations Company (GMO), does not relate to, and is not filed by, KCP&L. KCP&L makes no representation as to that information. Neither Great Plains Energy nor its other subsidiaries have any obligation in respect of KCP&L's debt securities and holders of such securities should not consider Great Plains Energy's or its other subsidiaries' financial resources or results of operations in making a decision with respect to KCP&L's debt securities. Similarly, KCP&L has no obligation in respect of securities of Great Plains Energy or its other subsidiaries.

CAUTIONARY STATEMENTS REGARDING CERTAIN FORWARD-LOOKING INFORMATION
Statements made in this report that are not based on historical facts are forward-looking, may involve risks and uncertainties, and are intended to be as of the date when made. Forward-looking statements include, but are not limited to, the outcome of regulatory proceedings, cost estimates of capital projects and other matters affecting future operations. In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, Great Plains Energy and KCP&L are providing a number of important factors that could cause actual results to differ materially from the provided forward-looking information. These important factors include: future economic conditions in regional, national and international markets and their effects on sales, prices and costs; prices and availability of electricity in regional and national wholesale markets; market perception of the energy industry, Great Plains Energy and KCP&L; changes in business strategy, operations or development plans; the outcome of contract negotiations for goods and services; effects of current or proposed state and federal legislative and regulatory actions or developments, including, but not limited to, deregulation, re-regulation and restructuring of the electric utility industry; decisions of regulators regarding rates the Companies can charge for electricity; adverse changes in applicable laws, regulations, rules, principles or practices governing tax, accounting and environmental matters including, but not limited to, air and water quality; financial market conditions and performance including, but not limited to, changes in interest rates and credit spreads and in availability and cost of capital and the effects on nuclear decommissioning trust and pension plan assets and costs; impairments of long-lived assets or goodwill; credit ratings; inflation rates; effectiveness of risk management policies and procedures and the ability of counterparties to satisfy their contractual commitments; impact of terrorist acts, including, but not limited to, cyber terrorism; ability to carry out marketing and sales plans; weather conditions including, but not limited to, weather-related damage and their effects on sales, prices and costs; cost, availability, quality and deliverability of fuel; the inherent uncertainties in estimating the effects of weather, economic conditions and other factors on customer consumption and financial results; ability to achieve generation goals and the occurrence and duration of planned and unplanned generation outages; delays in the anticipated in-service dates and cost increases of generation, transmission, distribution or other projects; Great Plains Energy's ability to successfully manage transmission joint venture; the inherent risks associated with the ownership and operation of a nuclear facility including, but not limited to, environmental, health, safety, regulatory and financial risks; workforce risks, including, but not limited to, increased costs of retirement, health care and other benefits; and other risks and uncertainties.

This list of factors is not all-inclusive because it is not possible to predict all factors. Part I Item 1A Risk Factors included in this report should be carefully read for further understanding of potential risks for each of Great Plains Energy and KCP&L. Other sections of this report and other periodic reports filed by each of Great Plains Energy and KCP&L with the Securities and Exchange Commission (SEC) should also be read for more information regarding risk factors. Each forward-looking statement speaks only as of the date of the particular statement. Great Plains Energy and KCP&L undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found throughout this report.

Abbreviation or Acronym	Definition
AEPTHC	AEP Transmission Holding Company, LLC, a wholly owned subsidiary of American Electric Power Company, Inc.
AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
Board	Great Plains Energy Board of Directors
CCRs	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
Company	Great Plains Energy Incorporated and its consolidated subsidiaries
Companies	Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries
DOE	Department of Energy
EBITDA	Earnings before interest, income taxes, depreciation and amortization
ECA	Energy Cost Adjustment
EIRR	Environmental Improvement Revenue Refunding
EPA	Environmental Protection Agency
EPS	Earnings per common share
ERISA	Employee Retirement Income Security Act of 1974, as amended
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	The Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GMO	KCP&L Greater Missouri Operations Company, a wholly owned subsidiary of Great Plains Energy
GPETHC	GPE Transmission Holding Company LLC, a wholly owned subsidiary of Great Plains Energy
Great Plains Energy	Great Plains Energy Incorporated and its consolidated subsidiaries
ISO	Independent System Operator
KCC	The State Corporation Commission of the State of Kansas
KCP&L	Kansas City Power & Light Company, a wholly owned subsidiary of Great Plains Energy, and its consolidated subsidiaries
KCP&L Receivables Company	Kansas City Power & Light Receivables Company, a wholly owned subsidiary of KCP&L
KDHE	Kansas Department of Health and Environment
kWh	Kilowatt hour
MATS	Mercury and Air Toxics Standards
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MDNR	Missouri Department of Natural Resources
MEEIA	Missouri Energy Efficiency Investment Act

Abbreviation or Acronym	Definition
MGP	Manufactured gas plant
MPS Merchant	MPS Merchant Services, Inc., a wholly owned subsidiary of GMO
MPSC	Public Service Commission of the State of Missouri
MW	Megawatt
MWh	Megawatt hour
NAV	Net Asset Value
NERC	North American Electric Reliability Corporation
NEIL	Nuclear Electric Insurance Limited
NOL	Net operating loss
NO_x	Nitrogen oxide
NPNS	Normal purchases and normal sales
NRC	Nuclear Regulatory Commission
OCI	Other Comprehensive Income
PRB	Powder River Basin
QCA	Quarterly Cost Adjustment
RCRA	Resource Conservation and Recovery Act
RESRAM	Renewable Energy Standard Rate Adjustment Mechanism
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
SERP	Supplemental Executive Retirement Plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
TCR	Transmission Congestion Right
TDC	Transmission Delivery Charge
Transource	Transource Energy, LLC and its subsidiaries, 13.5% owned by GPETHC
WCNOC	Wolf Creek Nuclear Operating Corporation
Wolf Creek	Wolf Creek Generating Station

PART I

ITEM 1. BUSINESS

General

Great Plains Energy Incorporated and Kansas City Power & Light Company are separate registrants filing this combined annual report on Form 10-K. The terms "Great Plains Energy," "Company," "KCP&L" and "Companies" are used throughout this report. "Great Plains Energy" and the "Company" refer to Great Plains Energy Incorporated and its consolidated subsidiaries, unless otherwise indicated. "KCP&L" refers to Kansas City Power & Light Company and its consolidated subsidiaries. "Companies" refers to Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries.

Information in other Items of this report as to which reference is made in this Item 1 is hereby incorporated by reference in this Item 1. The use of terms such as "see" or "refer to" shall be deemed to incorporate into this Item 1 the information to which such reference is made.

GREAT PLAINS ENERGY INCORPORATED

Great Plains Energy, a Missouri corporation incorporated in 2001 and headquartered in Kansas City, Missouri, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries. Great Plains Energy's wholly owned direct subsidiaries with significant operations are as follows:

- KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (KCP&L Receivables Company).
- GMO is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO has two active wholly owned subsidiaries, GMO Receivables Company and MPS Merchant Services, Inc. (MPS Merchant). MPS Merchant has certain long-term natural gas contracts remaining from its former non-regulated trading operations.

Great Plains Energy also wholly owns GPE Transmission Holding Company, LLC (GPETHC). GPETHC owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC (AEPTHC), a subsidiary of American Electric Power Company, Inc. GPETHC accounts for its investment in Transource under the equity method. Transource is focused on the development of competitive electric transmission projects.

Great Plains Energy's sole reportable business segment is electric utility. For information regarding the revenues, income and assets attributable to the electric utility business segment, see Note 22 to the consolidated financial statements. Comparative financial information and discussion regarding the electric utility business segment can be found in Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A).

The electric utility segment consists of KCP&L, a regulated utility, GMO's regulated utility operations which include its Missouri Public Service and St. Joseph Light & Power divisions and GMO Receivables Company. Electric utility serves approximately 846,100 customers located in western Missouri and eastern Kansas. Customers include approximately 744,900 residences, 98,600 commercial firms and 2,600 industrials, municipalities and other electric utilities. Electric utility's retail revenues averaged approximately 91% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of electric utility's revenues. Electric utility is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Electric utility's total electric revenues were 100% of Great Plains Energy's revenues over the last three years. Electric utility's net income accounted for approximately 105%, 100% and 103% of Great Plains Energy's net income in 2015, 2014 and 2013, respectively.

Regulation

KCP&L and GMO are regulated by the Public Service Commission of the State of Missouri (MPSC) and KCP&L is also regulated by The State Corporation Commission of the State of Kansas (KCC) with respect to retail rates, certain accounting matters, standards of service and, in certain cases, the issuance of securities, certification of facilities and service territories. KCP&L and GMO are also subject to regulation by The Federal Energy Regulatory Commission (FERC) with respect to transmission, wholesale sales and rates, and other matters. KCP&L has a 47% ownership interest in Wolf Creek Generating Station (Wolf Creek), which is subject to regulation by the Nuclear Regulatory Commission (NRC) with respect to licensing, operations and safety-related requirements.

The table below summarizes the rate orders in effect for KCP&L's and GMO's retail rate jurisdictions.

	Regulator	Allowed Return on Equity	Rate-Making Equity Ratio	Rate Base (in billions)	Effective Date
KCP&L Missouri	MPSC	9.5%	50.09%	$2.6	September 2015
KCP&L Kansas	KCC	9.3%	50.48%	$2.1	October 2015
GMO	MPSC	9.7%	52.3%[a]	$1.8	January 2013

[a] The MPSC authorized an equity ratio of 52.6% or approximately 52.3% after including other comprehensive income

Missouri and Kansas jurisdictional retail revenues averaged approximately 71% and 29%, respectively, of electric utility's total retail revenues over the last three years.

See Item 7 MD&A, Critical Accounting Policies section, and Note 5 to the consolidated financial statements for additional information concerning regulatory matters.

Competition

Missouri and Kansas continue on the fully integrated retail utility model. As a result, electric utility does not compete with others to supply and deliver electricity in its franchised service territory, although other sources of energy can provide alternatives to retail electric utility customers. If Missouri or Kansas were to pass and implement legislation authorizing or mandating retail choice, electric utility may no longer be able to apply regulated utility accounting principles to deregulated portions of its operations and may be required to write off certain regulatory assets and liabilities.

Electric utility competes in the wholesale market to sell power in circumstances when the power it generates is not required for customers in its service territory. This competition primarily occurs within the SPP Integrated Marketplace, in which KCP&L and GMO are participants. Similar to other Regional Transmission Organization (RTO) or Independent System Operator (ISO) markets currently operating, this marketplace determines which generating units among market participants should run, within the operating constraints of a unit, at any given time for maximum cost-effectiveness.

In this regard, electric utility competes with owners of other generating stations and other power suppliers, principally other utilities within the SPP Integrated Marketplace, on the basis of availability and price. Electric utility's wholesale revenues averaged approximately 7% of its total revenues over the last three years.

Power Supply

Electric utility has approximately 6,400 MWs of owned generating capacity. The projected peak summer demand for 2016 is approximately 5,800 MWs. Electric utility expects to meet its projected capacity requirements for the foreseeable future with its generation assets and power and capacity purchases.

KCP&L and GMO are members of the the Southwest Power Pool, Inc. (SPP). The SPP is an RTO mandated by FERC to ensure reliable supply of power, adequate transmission infrastructure and competitive wholesale prices of electricity. As members of the SPP, KCP&L and GMO are required to maintain a capacity margin of at least 12% of their projected peak summer demand. This net positive supply of capacity and energy is maintained through their generation assets, capacity agreements, power purchase agreements and peak demand reduction programs. The

capacity margin is designed to ensure the reliability of electric energy in the SPP region in the event of operational failure of power generating units utilized by the members of the SPP.

Fuel

The principal fuel sources for electric utility's electric generation are coal and nuclear fuel. It is expected, with normal weather, that approximately 96% of 2016 generation will come from these sources with the remainder provided by wind, natural gas and oil. The actual 2015 and estimated 2016 fuel mix and delivered cost in cents per net kilowatt hour (kWh) generated are outlined in the following table.

	Fuel Mix [(a)]		Fuel cost in cents per net kWh generated	
Fuel	**Estimated 2016**	**Actual 2015**	**Estimated 2016**	**Actual 2015**
Coal	81 %	80 %	1.84	2.06
Nuclear	15	17	0.68	0.67
Natural gas and oil	2	1	5.35	10.78
Wind	2	2	—	—
Total Generation	100 %	100 %	1.70	1.78

[(a)] Fuel mix based on percent of net MWhs generated.

Coal

During 2016, electric utility's generating units, including jointly owned units, are projected to burn approximately 16 million tons of coal. KCP&L and GMO have entered into coal-purchase contracts with various suppliers in Wyoming's Powder River Basin (PRB), the nation's principal supply region of low-sulfur coal, and with local suppliers. The coal to be provided under these contracts is expected to satisfy approximately 98% of the projected coal requirements for 2016, approximately 79% for 2017 and approximately 49% for 2018. The remainder of the coal requirements is expected to be fulfilled through additional contracts or spot market purchases. KCP&L and GMO have entered into coal contracts over time at higher average prices affecting coal costs for 2016 and beyond.

KCP&L and GMO have also entered into rail transportation contracts with various railroads to transport coal from the PRB to their generating units. The transportation services to be provided under these contracts are expected to satisfy almost all of the projected transportation requirements for 2016 through 2020. The contract rates adjust for changes in railroad costs.

Nuclear Fuel

KCP&L owns 47% of Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, which is electric utility's only nuclear generating unit. Wolf Creek purchases uranium and has it processed for use as fuel in its reactor. This process involves conversion of uranium concentrates to uranium hexafluoride, enrichment of uranium hexafluoride and fabrication of nuclear fuel assemblies. The owners of Wolf Creek have on hand or under contract all of the uranium and conversion services needed to operate Wolf Creek through March 2018 and approximately 37% after that date through September 2022. The owners also have under contract all of the uranium enrichment and fabrication required to operate Wolf Creek through March 2027 and September 2025, respectively.

See Note 4 to the consolidated financial statements for additional information regarding nuclear plant.

Natural Gas

At December 31, 2015, GMO had hedged approximately 66%, 18% and 8% of its expected on-peak natural gas generation and natural gas equivalent purchased power price exposure for 2016, 2017 and 2018, respectively.

Purchased Power
KCP&L and GMO purchase power to meet their customers' needs, to satisfy firm power commitments or to meet renewable energy standards. Electric utility's purchased power from others, as a percentage of MWh requirements, averaged approximately 19% over the last three years.

KCP&L has long-term power purchase agreements for approximately 637 MWs of wind and hydroelectric generation which expire in 2023 through 2036. GMO has long-term power purchase agreements for approximately 159 MWs of wind generation which expire in 2032.

Management believes electric utility will be able to obtain enough power to meet its future demands due to the coordination of planning and operations in the SPP region; however, price and availability of power purchases may be impacted during periods of high demand.

Environmental Matters
See Note 14 to the consolidated financial statements for information regarding environmental matters.

KANSAS CITY POWER & LIGHT COMPANY

KCP&L, a Missouri corporation incorporated in 1922 and headquartered in Kansas City, Missouri, is an integrated, regulated electric utility that engages in the generation, transmission, distribution and sale of electricity. KCP&L serves approximately 527,000 customers located in western Missouri and eastern Kansas. Customers include approximately 465,200 residences, 59,700 commercial firms, and 2,100 industrials, municipalities and other electric utilities. KCP&L's retail revenues averaged approximately 88% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of KCP&L's revenues. KCP&L is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Missouri and Kansas jurisdictional retail revenues averaged approximately 55% and 45%, respectively, of total retail revenues over the last three years.

Great Plains Energy and KCP&L Employees
At December 31, 2015, Great Plains Energy and KCP&L had 2,899 employees, including 1,789 represented by three local unions of the International Brotherhood of Electrical Workers (IBEW). KCP&L has labor agreements with Local 1613, representing clerical employees (expires March 31, 2018), with Local 1464, representing transmission and distribution workers (expires January 31, 2018), and with Local 412, representing power plant workers (expires February 28, 2018).

Executive Officers
All of the individuals in the following table have been officers or employees in the responsible positions with the Company noted below for the past five years unless otherwise indicated in the footnotes. The executive officers were reappointed to the indicated positions by the respective boards of directors, effective January 1, 2016, to hold such positions until their resignation, removal or the appointment of their successors. There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection. Each executive officer holds the same position with GMO as he or she does with KCP&L.

Name	Age	Current Position(s)	Year First Assumed an Officer Position
Terry Bassham [(a)]	55	Chairman of the Board, President and Chief Executive Officer - Great Plains Energy and KCP&L	2005
Scott H. Heidtbrink [(b)]	54	Executive Vice President and Chief Operating Officer - KCP&L	2008
Kevin E. Bryant [(c)]	40	Senior Vice President - Finance and Strategy and Chief Financial Officer - Great Plains Energy and KCP&L	2006
Steven P. Busser [(d)]	47	Vice President - Business Planning and Controller - Great Plains Energy and KCP&L	2014
Charles A. Caisley [(e)]	43	Vice President - Marketing and Public Affairs - Great Plains Energy and KCP&L	2011
Michael L. Deggendorf [(f)]	54	Senior Vice President - Corporate Services - KCP&L	2005
Ellen E. Fairchild [(g)]	54	Vice President, Chief Compliance Officer and Corporate Secretary - Great Plains Energy and KCP&L	2010
Heather A. Humphrey [(h)]	45	General Counsel and Senior Vice President - Human Resources - Great Plains Energy and KCP&L	2010
Darrin R. Ives [(i)]	46	Vice President - Regulatory Affairs - KCP&L	2013
Lori A. Wright [(j)]	53	Vice President - Investor Relations and Treasurer - Great Plains Energy and KCP&L	2002

(a) Mr. Bassham was appointed Chairman of the Board in May 2013 and has served as Chief Executive Officer of Great Plains Energy, KCP&L and GMO since 2012. He has served as President of each company since 2011. He previously served as President and Chief Operating Officer of Great Plains Energy, KCP&L and GMO (2011-2012) and as Executive Vice President - Utility Operations of KCP&L and GMO (2010-2011). He was Executive Vice President - Finance and Strategic Development and Chief Financial Officer of Great Plains Energy (2005-2010) and of KCP&L and GMO (2009-2010).

(b) Mr. Heidtbrink was appointed Executive Vice President and Chief Operating Officer of KCP&L and GMO in 2012. He previously served as Senior Vice President - Supply of KCP&L and GMO (2009-2012). He was Senior Vice President - Corporate Services of KCP&L and GMO (2008), and Vice President - Power Generation & Energy Resources (2006-2008) of GMO.

(c) Mr. Bryant was appointed Vice President - Finance and Strategy and Chief Financial Officer of Great Plains Energy, KCP&L and GMO in 2015. He previously served as Vice President - Strategic Planning of Great Plains Energy, KCP&L and GMO (2014). He served as Vice President - Investor Relations and Strategic Planning and Treasurer of Great Plains Energy, KCP&L and GMO (2013). He served as Vice President - Investor Relations and Treasurer of Great Plains Energy, KCP&L and GMO (2011-2013). He was Vice President - Strategy and Risk Management of KCP&L and GMO (2011) and Vice President - Energy Solutions (2006-2011) of KCP&L and GMO.

(d) Mr. Busser was appointed Vice President - Business Planning and Controller of Great Plains Energy, KCP&L and GMO in 2014. He previously served as Vice President - Treasurer of El Paso Electric Company (2011-2014). Prior to that, he served as Vice President - Treasurer and Chief Risk Officer (2006-2011) and Vice President - Regulatory Affairs and Treasurer (2004-2006) of El Paso Electric Company. Effective March 1, 2016, Mr. Busser was appointed Vice President - Risk Management and Controller of Great Plains Energy, KCP&L and GMO.

(e) Mr. Caisley was appointed Vice President - Marketing and Public Affairs of Great Plains Energy, KCP&L and GMO in 2011. He was Senior Director of Public Affairs (2008-2011) and Director of Governmental Affairs of KCP&L (2007-2008).

(f) Mr. Deggendorf was appointed Senior Vice President - Corporate Services of KCP&L and GMO in 2012. He previously served as Senior Vice President - Delivery of KCP&L and GMO (2008-2012). He was Vice President - Public Affairs of Great Plains Energy (2005-2008). Effective March 1, 2016, Mr. Deggendorf was appointed Senior Vice President of KCP&L and GMO.

(g) Ms. Fairchild was appointed Vice President, Chief Compliance Officer and Corporate Secretary of Great Plains Energy, KCP&L and GMO in 2010. She was Senior Director of Investor Relations and Assistant Secretary (2010) and Director of Investor Relations (2008-2010) of Great Plains Energy, KCP&L and GMO.

(h) Ms. Humphrey was appointed General Counsel in 2010 and Senior Vice President - Human Resources of Great Plains Energy, KCP&L and GMO in 2012. She previously served as Vice President - Human Resources of Great Plains Energy, KCP&L and GMO (2010-2012). She was Senior Director of Human Resources and Interim General Counsel of Great Plains Energy, KCP&L and GMO (2010) and Managing Attorney of KCP&L (2007-2010). Effective March 1, 2016, Ms. Humphrey was appointed Senior Vice President - Corporate Services and General Counsel of Great Plains Energy, KCP&L and GMO.

(i) Mr. Ives was appointed Vice President - Regulatory Affairs of KCP&L and GMO in 2013. He previously served as Senior Director - Regulatory Affairs of KCP&L and GMO (2011-2013). He was Assistant Controller of Great Plains Energy, KCP&L and GMO (2008 - 2011).

(j) Ms. Wright was appointed Vice President - Investor Relations and Treasurer of Great Plains Energy, KCP&L and GMO in 2014. Prior to this appointment, she served as Vice President - Business Planning and Controller of Great Plains Energy, KCP&L and GMO (2009-2014). She was Controller of Great Plains Energy and KCP&L (2002-2008) and GMO (2008). Effective March 1, 2016, Ms. Wright was appointed Vice President - Corporate Planning, Investor Relations and Treasurer of Great Plains Energy, KCP&L and GMO.

Available Information

Great Plains Energy's website is www.greatplainsenergy.com and KCP&L's website is www.kcpl.com. Information contained on these websites is not incorporated herein. The Companies make available, free of charge, on or through their websites, their annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after the companies electronically file such material with, or furnish it to, the SEC. In addition, the Companies make available on or through their websites all other reports, notifications and certifications filed electronically with the SEC.

The public may read and copy any materials that the Companies file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. For information on the operation of the Public Reference Room, please call the SEC at 1-800-SEC-0330. The SEC also maintains an Internet site at http://www.sec.gov that contains reports, proxy statements and other information regarding the Companies.

Investors should note that the Companies announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, the Companies may use the Investor Relations section of Great Plains Energy's website (www.greatplainsenergy.com) to communicate with investors about Great Plains Energy and KCP&L. It is possible that the financial and other information posted there could be deemed to be material information. The information on Great Plains Energy's website is not part of this document.

ITEM 1A. RISK FACTORS

Actual results in future periods for Great Plains Energy and KCP&L could differ materially from historical results and the forward-looking statements contained in this report. The Companies' business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond their control. Additional risks and uncertainties not presently known or that the Companies' management currently believes to be immaterial may also adversely affect the Companies. This information, as well as the other information included in this report and in the other documents filed with the SEC, should be carefully considered before making an investment in the securities of Great Plains Energy or KCP&L. Risk factors of KCP&L are also risk factors of Great Plains Energy.

Utility Regulatory Risks:

Complex utility regulation could adversely affect the Companies' results of operations, financial position and cash flows.
The Companies are subject to, or affected by, extensive federal and state utility regulation, including regulation by the MPSC, KCC, FERC, NRC, North American Electric Reliability Corporation (NERC) and SPP. The Companies must address in their business planning and management of operations the effects of existing and proposed laws and regulations and potential changes in the regulatory framework, including initiatives by federal and state legislatures, RTOs, utility regulators and taxing authorities. Failure of the Companies to obtain adequate rates or regulatory approvals in a timely manner, new or changed laws, regulations, standards, interpretations or other legal requirements, deterioration of the Companies' relationship with regulators and increased compliance costs and potential non-compliance consequences may materially affect the Companies' results of operations, financial position and cash flows. Additionally, regulators may impose burdensome restrictions and conditions on the Companies' transactions and ventures, rendering them less attractive from a financial or operational perspective. Certain of these risks are addressed in greater detail below.

The outcome of retail rate proceedings could have a material impact on the business and is largely outside the Companies' control.
The rates that KCP&L and GMO are allowed to charge their customers significantly influence the Companies' results of operations, financial position and cash flows. These rates are subject to the determination, in large part, of governmental entities outside of the Companies' control, including the MPSC, KCC and FERC.

The utility rate-setting principle generally applicable to KCP&L and GMO is that rates should provide a reasonable opportunity to recover expenses and investments prudently incurred to provide utility service plus a reasonable return on such investments. Various expenses incurred by KCP&L and GMO have been excluded from rates by the MPSC and KCC in past rate cases as not being prudently incurred or not providing utility customer benefit, and there is a risk that certain expenses incurred in the future may not be recovered in rates. Third-parties often intervene in the utilities' rate cases and argue that certain costs have not been prudently incurred or are otherwise not recoverable in rates. The MPSC and KCC also have in the past and may in the future exclude from rates all or a portion of investments in various facilities as not being prudently incurred or not being useful in providing utility service.

As discussed in the "Environmental Risks" and "Financial Risks" sections below, the Companies' capital expenditures are expected to be substantial over the next several years and there is a risk that a portion of the capital costs could be excluded from rates in future rate cases.

The Companies are also exposed to cost-recovery shortfalls due to the inherent "regulatory lag" in the rate-setting process, especially during periods of significant cost inflation or declining retail usage, as KCP&L's and GMO's utility rates are generally based on historical information and are not subject to adjustment between rate cases, other than principally for fuel, purchased power, transmission and property taxes for KCP&L in Kansas; fuel, purchased power, certain transmission costs and demand-side investments for KCP&L in Missouri; and fuel, purchased power, certain transmission costs, demand-side investments and renewable energy (solar rebates) for GMO. These and other factors may result in under-recovery of costs, failure to earn the authorized return on investment, or both.

There are mandatory renewable energy standards in Missouri and voluntary renewable energy goals in Kansas. There is also the potential for future federal or state mandatory energy efficiency requirements.

Failure to timely recover the full investment costs of capital projects, the impact of renewable energy and energy efficiency programs, other utility costs and expenses due to regulatory disallowances, regulatory lag or other factors could lead to lowered credit ratings, reduced access to capital markets, increased financing costs, lower flexibility due to constrained financial resources and increased collateral security requirements, or reductions or delays in planned capital expenditures. In response to competitive, economic, political,

legislative, public perception (including, but not limited to, the Companies' environmental reputation) and regulatory pressures, the Companies may be subject to rate moratoriums, rate refunds, limits on rate increases, lower allowed returns on investments or rate reductions, including phase-in plans designed to spread the impact of rate increases over an extended period of time for the benefit of customers.

Regulatory requirements regarding utility operations may increase costs and may expose the Companies to compliance penalties or adverse rate consequences.
The FERC, NERC and SPP have implemented and enforce an extensive set of transmission system reliability, cyber security and critical infrastructure protection standards that apply to public utilities, including KCP&L and GMO. The MPSC and KCC have the authority to implement utility operational standards and requirements, such as vegetation management standards, facilities inspection requirements and quality of service standards. In addition, the Companies are also subject to health, safety and other requirements enacted by the Occupational Safety and Health Administration, the Department of Transportation, the Department of Labor and other federal and state agencies. As discussed more fully under "Operational Risks," the NRC extensively regulates nuclear power plants, including Wolf Creek. The costs of existing, new or modified regulations, standards and other requirements could have an adverse effect on the Companies' results of operations, financial position and cash flows as a result of increased operations or maintenance and capital expenditures for new facilities or to repair or improve existing facilities. In addition, failure to meet quality of service, reliability, cyber security, critical infrastructure protection, operational or other standards and requirements could expose the Companies to penalties, additional compliance costs, or adverse rate consequences.

Environmental Risks:

The Companies are subject to current and potential environmental requirements and the incurrence of environmental liabilities, any or all of which may adversely affect their business and financial results.
The Companies are subject to extensive federal, state and local environmental laws, regulations and permit requirements relating to air and water quality, waste management and disposal, natural resources and health and safety. In addition to imposing continuing compliance obligations and remediation costs for historical and pre-existing conditions, these laws, regulations and permits authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. There is also a risk that new environmental laws and regulations, new administrative or judicial interpretations of environmental laws and regulations, or the requirements in new or renewed environmental permits could adversely affect the Companies' operations. In addition, there is also a risk of lawsuits brought by third parties alleging violations of environmental commitments or requirements, claiming creation of a public nuisance or other matters, and seeking injunctions or monetary damages or other damages. Certain federal courts have held that state and local governments and private parties have standing to bring climate change tort suits seeking company-specific emission reductions and damages.

Environmental permits are subject to periodic renewal, which may result in more stringent permit conditions and limits. New facilities, or modifications of existing facilities, may require new environmental permits or amendments to existing permits. Delays in the environmental permitting process, public opposition and challenges, denials of permit applications, limits or conditions imposed in permits and the associated uncertainty may materially adversely affect the cost and timing of projects, and thus materially adversely affect the Companies' results of operations, financial position and cash flows.

KCP&L and GMO periodically seek recovery of capital costs and expenses for environmental compliance and remediation through rate increases; however, there can be no assurance that recovery of these costs would be granted. KCP&L and GMO may be subject to material adverse rate treatment in response to competitive, economic, political, legislative or regulatory pressures and/or public perception of the Companies' environmental reputation. The costs of compliance or noncompliance with environmental requirements, remediation costs, adverse outcomes of lawsuits, or failure to timely recover environmental costs could have a material adverse effect on the Companies' results of operations, financial position and cash flows. Certain of these matters are discussed in more detail below. See Note 14 to the consolidated financial statements for additional information regarding certain significant

environmental matters and Great Plains Energy's and KCP&L's current estimates of capital expenditures over the next five years to comply with environmental regulations.

Air and Climate Change

Management believes it is possible that additional federal or relevant state or local laws or regulations could be enacted to address global climate change. At the international level, in December 2015 the Paris Agreement was adopted by nearly 200 countries. The Paris Agreement did not result in any new, legally binding obligations on the United States to meet a particular greenhouse gas emissions target, but establishes a framework for international cooperation on climate change. Additional international agreements legally binding on the United States may be reached in the future. Such new laws, regulations or treaties could mandate new or increased requirements to control or reduce the emission of greenhouse gases, such as carbon dioxide (CO_2), which are created in the combustion of fossil fuels. These requirements could include, among other things, taxes or fees on fossil fuels or emissions, cap and trade programs, emission limits and clean or renewable energy standards. The Companies' current generation capacity is primarily coal-fired, and is estimated to produce about one ton of CO_2 per MWh, or approximately 21 million tons and 15 million tons of CO_2 per year for Great Plains Energy and KCP&L, respectively.

The Environmental Protection Agency (EPA) has enacted various regulations regarding the reporting and permitting of greenhouse gases and has proposed other regulations under the existing Clean Air Act. The EPA has established thresholds for greenhouse gas emissions, defining when Clean Air Act permits under the New Source Performance Standards, New Source Review and Title V operating permits programs would be required for new or existing industrial facilities and when the installation of best available control technology would be required. In August 2015, the EPA finalized its Clean Power Plan which sets CO_2 emission performance rates for existing affected fossil fuel-fired electric generating units. Specifically, the EPA translated those performance rates into a state goal measured in mass and rate based on each state's generation mix. The states have the ability to develop their own plans for affected units to achieve either the performance rates directly or the state goals, with guidelines for the development, submittal and implementation of those plans. In February 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan putting the rule on hold pending review in the United States Court of Appeals for the District of Columbia Circuit and any subsequent review by the U.S. Supreme Court if such review is sought. Compliance with the Clean Power Plan has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L; however, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until the outcome of pending litigation is known and/or the state plans to implement the Clean Power Plan are known. Additional federal and/or state legislation or regulation respecting greenhouse gas emissions may be proposed or enacted in the future. Requirements to reduce greenhouse gas emissions may cause the Companies to incur significant costs relating to their ongoing operations (such as for additional environmental control equipment, retiring and replacing existing generation, re-powering existing plants to utilize alternative fuel or selecting more costly generation alternatives), to procure emission allowance credits, or due to the imposition of taxes, fees or other governmental charges as a result of such emissions.

Rules issued by the EPA regarding emissions of mercury and other hazardous air pollutants, nitrogen oxide (NO_X), sulfur dioxide (SO_2) and particulates are also in a state of flux. Some of these rules have been overturned by the courts and remanded to the EPA to be revised consistent with the courts' orders while others are pending judicial review or are otherwise subject to revision. It is unknown what requirements and standards will be imposed in the future, when the Companies may have to comply or what costs may ultimately be required.

Missouri law currently requires at least 5% of the energy provided by certain utilities, including KCP&L and GMO, to come from renewable resources, including wind, solar, biomass and hydropower, increasing to 10% by 2018 and 15% by 2021, with a small portion (estimated to be about 2 MW for each of KCP&L and GMO) required to come from solar resources. Management believes that national renewable energy standards are also possible. The timing, provisions and impact of such possible future requirements,

including the cost to obtain and install new equipment to achieve compliance, cannot be reasonably estimated at this time. Such requirements could have a significant financial and operational impact on the Companies.

Water

The Clean Water Act and associated regulations enacted by the EPA form a comprehensive program to restore and preserve water quality. All of the Companies' generating facilities, and certain of their other facilities, are subject to the Clean Water Act.

In May 2014, the EPA finalized regulations regarding protection of aquatic life from being killed or injured by cooling water intake structures. KCP&L's generation facilities with cooling water intake structures are subject to the best technology available standards based on studies completed to comply with such standards. The rule provides flexibility to work with the states to develop the best technology available to minimize aquatic species impacted by being pinned against intake screens or drawn into cooling water systems.

KCP&L holds a permit from the MDNR covering water discharge from its Hawthorn Station. The permit authorizes KCP&L to, among other things, withdraw water from the Missouri River for cooling purposes and return the heated water to the Missouri River. KCP&L has applied for a renewal of this permit and the EPA has submitted an interim objection letter regarding the allowable amount of heat that can be contained in the returned water. Until this matter is resolved, KCP&L continues to operate under its current permit. Future water permit renewals at KCP&L's Iatan Station and at GMO's Sibley and Lake Road Stations could also be impacted by the allowable amount of heat that can be contained in the returned water. Great Plains Energy and KCP&L cannot predict the outcome of these matters; however, while less significant outcomes are possible, these matters may require a reduction in generation, installation of cooling towers or other technology to cool the water, or both, any of which could have a significant impact on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

In September 2015, the EPA finalized a revision of the technology-based effluent limitations guidelines and standards regulation to make the existing controls on discharges from steam electric power plants more stringent. The final rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. The new requirements for existing power plants would be phased in between 2018 and 2023.

Further, the possible effects of climate change, including potentially increased temperatures and reduced precipitation, could make it more difficult and costly to comply with the current and final permit requirements.

Solid Waste

Solid and hazardous waste generation, storage, transportation, treatment and disposal are regulated at the federal and state levels under various laws and regulations. In April 2015, the EPA published final regulations to regulate coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act (RCRA) Subtitle D to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The Companies principally use coal in generating electricity and dispose of CCRs in both on-site facilities and facilities owned by third parties. Current and future EPA regulations regarding the handling, disposal and remediation of CCRs could have a material adverse effect on the Companies' results of operations, financial position and cash flows.

Remediation

Under current law, the Companies are also generally responsible for any liabilities associated with the environmental condition of their properties and other properties at which the Companies arranged for the disposal or treatment of hazardous substances, including properties that they have previously owned or operated, such as manufactured gas plants (MGP), regardless of whether they were responsible for the

contamination or whether the liabilities arose before, during or after the time they owned or operated the properties or arranged for the disposal or treatment of hazardous substances.

Due to all of the above, the Companies' projected capital and other expenditures for environmental compliance are subject to significant uncertainties, including the timing of implementation of any new or modified environmental requirements, the limits imposed by such requirements and the types and costs of the compliance alternatives selected by the Companies. As a result, costs to comply with environmental requirements cannot be estimated with certainty, and actual costs could be significantly higher than projections. New environmental laws and regulations affecting the operations of the Companies may be adopted, and new interpretations of existing laws and regulations could be adopted or become applicable to the Companies or their facilities, any of which may materially adversely affect the Companies' business, adversely affect the Companies' ability to continue operating its power plants as currently done and substantially increase environmental expenditures or liabilities in the future.

Financial Risks:

Financial market disruptions and declines in credit ratings may increase financing costs and/or limit access to the credit markets, which may adversely affect liquidity and results.
The Companies' capital requirements are expected to be substantial over the next several years. The Companies rely on access to short-term money markets, revolving credit facilities provided by financial institutions and long-term capital markets as significant sources of liquidity for capital requirements not satisfied by cash flows from operations. The Companies also rely on bank-provided credit facilities for credit support, such as letters of credit, to support operations. The amount of credit support required for operations varies and is impacted by a number of factors.

Great Plains Energy, KCP&L, GMO and certain of their securities are rated by Moody's Investors Service and Standard & Poor's. These ratings impact the Companies' cost of funds and Great Plains Energy's ability to provide credit support for its subsidiaries. The interest rates on borrowings under the Companies' revolving credit agreements and on a portion of Great Plains Energy's debt are subject to increase as their respective credit ratings decrease. The amount of collateral or other credit support required under power supply and certain other agreements is also dependent on credit ratings.

Conditions in the United States capital and credit markets may deteriorate in the future for a variety of reasons, including, among others: instability in global markets, political uncertainty in the United States or abroad, fluctuations in the price of oil, geopolitical instability or other unforeseen events both in the United States and around the world. Adverse market conditions or decreases in Great Plains Energy's, KCP&L's or GMO's credit ratings could have material adverse effects on the Companies. These effects could include, among others: reduced access to capital and increased cost of funds; dilution resulting from equity issuances at reduced prices; changes in the type and/or increases in the amount of collateral or other credit support obligations required to be posted with contractual counterparties; increased nuclear decommissioning trust and pension and other post-retirement benefit plan funding requirements; rate case disallowance of KCP&L's or GMO's costs of capital; reductions in or delays of capital expenditures; or reductions in Great Plains Energy's ability to provide credit support for its subsidiaries. Any of these results could adversely affect the Companies' results of operations, financial position and cash flows. In addition, market disruption and volatility could have an adverse impact on the Companies' lenders, suppliers and other counterparties or customers, causing them to fail to meet their obligations.

Great Plains Energy has guaranteed some of GMO's long-term and short-term debt and payments under these guarantees may adversely affect Great Plains Energy's liquidity.
Great Plains Energy has issued guarantees covering $97.7 million of GMO's long-term debt. Great Plains Energy also guarantees GMO's commercial paper program. At December 31, 2015, GMO had $43.7 million of commercial paper outstanding. The guarantees obligate Great Plains Energy to pay amounts owed by GMO directly to the holders of the guaranteed debt in the event GMO defaults on its payment obligations. Great Plains Energy may also guarantee debt that GMO may issue in the future. Any guarantee payments could adversely affect Great Plains Energy's liquidity.

The inability of Great Plains Energy's subsidiaries to provide sufficient dividends to Great Plains Energy, or the inability otherwise of Great Plains Energy to pay dividends to its shareholders and meet its financial obligations would have an adverse effect.

Great Plains Energy is a holding company with no significant operations of its own. The primary source of funds for payment of dividends to its shareholders and its other financial obligations is dividends paid to it by its subsidiaries, particularly KCP&L and GMO. The ability of Great Plains Energy's subsidiaries to pay dividends or make other distributions, and accordingly, Great Plains Energy's ability to pay dividends on its common stock and meet its financial obligations principally depends on the actual and projected earnings and cash flow, capital requirements and general financial position of its subsidiaries, as well as regulatory factors, financial covenants, general business conditions and other matters.

In addition, Great Plains Energy, KCP&L and GMO are subject to certain corporate and regulatory restrictions and financial covenants that could affect their ability to pay dividends. Great Plains Energy's articles of incorporation restrict the payment of common stock dividends in the event common equity is 25% or less of total capitalization. In addition, if preferred stock dividends are not declared and paid when scheduled, Great Plains Energy could not declare or pay common stock dividends or purchase any common shares. If the unpaid preferred stock dividends equal four or more full quarterly preferred dividends, the preferred shareholders, voting as a single class, could elect the smallest number of directors necessary to constitute a majority of the full Great Plains Energy Board of Directors. Certain conditions in the MPSC and KCC orders authorizing the holding company structure require Great Plains Energy and KCP&L to maintain consolidated common equity of at least 30% and 35%, respectively, of total capitalization (including only the amount of short-term debt in excess of the amount of construction work in progress). Under the Federal Power Act, KCP&L and GMO generally can pay dividends only out of retained earnings. The revolving credit agreements of Great Plains Energy, KCP&L and GMO and the note purchase agreement for GMO's Series A, B and C Senior Notes contain a covenant requiring each company to maintain a consolidated indebtedness to consolidated total capitalization ratio of not more than 0.65 to 1.00. Great Plains Energy's Board of Directors regularly evaluates the common stock dividend policy and determines an appropriate dividend each quarter, after taking into account such factors as, among other things, earnings, financial condition and cash flows from KCP&L and GMO, as well as general economic conditions. While the corporate and regulatory restrictions and financial covenants discussed above are not expected to affect the Companies' ability to pay dividends at the current level in the foreseeable future, Great Plains Energy cannot assure common shareholders that the dividend will be paid in the future or that, if paid, dividends will be at the same amount or with the same frequency as in the past.

Market performance, increased retirements and retirement plan regulations could significantly impact retirement plan funding requirements and associated cash needs and expenses.

Substantially all of the Companies' and WCNOC's employees participate in defined benefit retirement and other post-retirement plans. Former employees also have accrued benefits in defined benefit retirement and other post-retirement plans. The costs of these plans depend on a number of factors, including the rates of return on plan assets, the level and nature of the provided benefits, discount rates, the interest rates used to measure required minimum funding levels, changes in benefit design, changes in laws or regulations, and the Companies' required or voluntary contributions to the plans. The Companies currently have substantial unfunded liabilities under these plans. Also, if the rate of retirements exceeds planned levels, or if these plans experience adverse market returns on investments, or if interest rates materially fall, the Companies' contributions to the plans could rise substantially over historical levels. In addition, changes in accounting rules and assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, could have a significant impact on the Companies' results of operations, financial position and cash flows.

The use of derivative contracts in the normal course of business could result in losses that could negatively impact the Companies' results of operations, financial position and cash flows.

The Companies use derivative instruments, such as swaps, options, futures and forwards, to manage commodity and financial risks. Losses could be recognized as a result of volatility in the market values of these contracts, if a counterparty fails to perform, or if the underlying transactions which the derivative instruments are intended to hedge fail to materialize. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or the use of estimates. As

a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

As a service provider to GMO, KCP&L may have exposure to GMO's financial performance and operations. GMO has no employees of its own. KCP&L employees operate and manage GMO's properties, and KCP&L charges GMO for the cost of these services. These arrangements may pose risks to KCP&L, including possible claims arising from actions of KCP&L employees in operating GMO's properties and providing other services to GMO. KCP&L's claims for reimbursement for services provided to GMO are unsecured and rank equally with other unsecured obligations of GMO. KCP&L's ability to be reimbursed for the costs incurred for the benefit of GMO depends on the financial ability of GMO to make such payments.

Customer and Weather-Related Risks:

The results of operations, financial position and cash flows of the Companies can be materially affected by changes in customer electricity consumption.
Changes in customer electricity consumption due to sustained financial market disruptions, downturns or sluggishness in the economy, technological advances, energy efficiency or other factors may adversely affect the Companies' results of operations, financial position and cash flows.

Technological advances, energy efficiency, or other energy conservation measures could reduce customer electricity consumption. KCP&L and GMO generate electricity at central station power plants to achieve economies of scale and produce electricity at a competitive cost. There are distributed generation technologies that produce electricity, including microturbines, wind turbines, fuel cells and solar cells, that have recently become more cost competitive. If this trend continues, the Companies customer electricity consumption could be reduced. Changes in technology could also alter the channels through which the Companies' customers purchase or use electricity, which could reduce the Companies customer electricity consumption.

Weather is a major driver of the Companies' results of operations, financial position and cash flow.
Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Great Plains Energy and KCP&L are significantly impacted by seasonality, with approximately one-third of their retail electric revenues recorded in the third quarter. Unusually mild winter or summer weather can adversely affect sales. In addition, severe weather, including but not limited to tornados, snow, rain, flooding and ice storms can be destructive causing outages and property damage that can potentially result in additional expenses, lower revenues and additional capital restoration costs. KCP&L's and GMO's rates may not always be adjusted timely and adequately to reflect these increased costs. Some of the Companies' generating stations utilize water from the Missouri River for cooling purposes. Low water and flow levels can increase maintenance costs at these stations and, if these levels were to get low enough, could require modifications to plant operations. The possible effects of climate change (such as increased temperatures, increased occurrence of severe weather or reduced precipitation, among other possible results) could potentially increase the volatility of demand and prices for energy commodities, increase the frequency and impact of severe weather, increase the frequency of flooding or decrease water and flow levels. To the extent the frequency of extreme weather events increases, this could increase the Companies' cost in providing service.

Operational Risks:

Operational risks may adversely affect the Companies' results of operations, financial position and cash flows.
The operation of the Companies' electric generation, transmission, distribution and information systems involves many risks, including breakdown or failure of equipment, aging infrastructure, processes and personnel performance; problems that delay or increase the cost of returning facilities to service after outages; limitations that may be imposed by equipment conditions or environmental, safety or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; labor disputes; difficulties with the implementation or continued operation of information systems; transmission scheduling constraints; and catastrophic events such as fires, floods, droughts, explosions, terrorism, cyber threats, severe weather or other similar occurrences. Furthermore, to the

extent that a cyber attack was successful, customer and employee information may be stolen, equipment may be destroyed or damaged and operations may be disrupted. Any such equipment or system outage or constraint can, among other things:

- in the case of generation equipment, affect operating costs, increase capital requirements and costs, increase purchased power volumes and costs and reduce wholesale sales opportunities;
- in the case of transmission equipment, affect operating costs, increase capital requirements and costs, require changes in the source of generation and affect wholesale sales opportunities and the ability to meet regulatory reliability and security requirements;
- in the case of distribution systems, affect revenues and operating costs, increase capital requirements and costs, and affect the ability to meet regulatory service metrics and customer expectations; and
- in the case of information systems, affect the control and operations of generation, transmission, distribution, customer information and other business operations and processes, increase operating costs, increase capital requirements and costs, and affect the ability to meet regulatory reliability and security requirements and customer expectations.

With the exception of Hawthorn No. 5, which was substantially rebuilt in 2001, and Iatan No. 2, which was completed in 2010, all of KCP&L's and GMO's coal-fired generating units and its nuclear generating unit were constructed prior to 1986. The age of these generating units increases the risk of unplanned outages, reduced generation output and higher maintenance expense. Training, preventive maintenance and other programs have been implemented, but there is no assurance that these programs will prevent or minimize future breakdowns or failures of the Companies' generation facilities or increased maintenance expense. Furthermore, aging transmission and distribution facilities are more prone to failure than new facilities, which results in higher maintenance expense and the need to replace these facilities with new infrastructure. The higher maintenance costs and capital expenditures for new replacement infrastructure could cause additional rate volatility for the Companies' customers, resistance by the Companies' regulators to allow customer rate increases and/or regulatory lag.

The Companies currently have general liability and property insurance in place to cover their facilities in amounts that management considers appropriate. These policies, however, do not cover the Companies' transmission or distribution systems, and the cost of repairing damage to these systems may adversely affect the Companies' results of operations, financial position and cash flows. Such policies are subject to certain limits and deductibles and do not include business interruption coverage. Insurance coverage may not be available in the future at reasonable costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of the Companies' facilities may not be sufficient to restore the loss or damage.

These and other operating events may reduce the Companies' revenues, increase their costs, or both, and may materially affect their results of operations, financial position and cash flows.

The cost and schedule of capital projects may materially change and expected performance may not be achieved.

Great Plains Energy's and KCP&L's businesses are capital intensive. The Companies currently have significant capital projects pending and may also have significant capital projects in the future. The risks of any capital project include: that actual costs may exceed estimated costs due to inflation or other factors; risks associated with the incurrence of additional debt or the issuance of additional equity to fund such projects; delays that may occur in obtaining permits and materials; the failure of suppliers and contractors to perform as required under their contracts; inadequate availability or increased cost of equipment, materials or qualified craft labor; delays related to inclement weather; the scope, cost and timing of projects may change due to new or changed environmental requirements, health and safety laws or other factors; and other events beyond the Companies' control may occur that may materially affect the schedule, cost and performance of these projects.

These and other risks could materially increase the estimated costs of capital projects, delay the in-service dates of projects, adversely affect the performance of the projects, and/or require the Companies to purchase additional

electricity to supply their respective retail customers until the projects are completed. Thus, these risks may significantly affect the Companies' results of operations, financial position and cash flows.

Failure of one or more generation plant co-owners to pay their share of construction or operations and maintenance costs could increase the Companies' costs and capital requirements.
KCP&L owns 47% of Wolf Creek, 50% of La Cygne Station, 70% of Iatan No. 1 and 55% of Iatan No. 2. GMO owns 18% of both Iatan units and 8% of Jeffrey Energy Center. The remaining portions of these facilities are owned by other utilities that are contractually obligated to pay their proportionate share of capital and other costs.

While the ownership agreements provide that a defaulting co-owner's share of the electricity generated can be sold by the non-defaulting co-owners, there is no assurance that the revenues received will recover the increased costs borne by the non-defaulting co-owners. Occurrence of these or other events could materially increase the Companies' costs and capital requirements.

The Companies are subject to information security risks and risks of unauthorized access to their systems.
In the course of their businesses, the Companies handle a range of system security and sensitive customer information. KCP&L and GMO are subject to laws and rules issued by different agencies concerning safeguarding and maintaining the confidentiality of this information. A security breach of the utilities' information systems such as theft or the inappropriate release of certain types of information, including confidential customer information or system operating information, could have a material adverse impact on the results of operations, financial position and cash flows of the Companies.

KCP&L and GMO operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructures. Despite implementation of security measures, the technology systems are vulnerable to disability, failures, employee error or malfeasance, or unauthorized access. Such failures or breaches of the systems could impact the reliability of generation, transmission and distribution systems, result in legal claims and proceedings, damage the Companies' reputation and also subject the Companies to financial harm. If the technology systems were to fail or be breached and not recovered in a timely way, critical business functions could be impaired and sensitive confidential data could be compromised, which could have a material adverse impact on the Companies' results of operations, financial position and cash flows.

KCP&L is exposed to risks associated with the ownership and operation of a nuclear generating unit, which could result in an adverse effect on the Companies' business and financial results.
KCP&L owns 47% of Wolf Creek. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including Wolf Creek. In the event of non-compliance, the NRC has the authority to impose fines, shut down the facilities, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Additionally, the non-compliance of other nuclear facility operators with applicable regulations or the occurrence of a serious nuclear incident anywhere in the world could result in increased regulation of the nuclear industry as a whole. Any revised safety requirements promulgated by the NRC could result in substantial capital expenditures at Wolf Creek.

Wolf Creek has the lowest fuel cost per MWh of any of KCP&L's generating units. An extended outage of Wolf Creek, whether resulting from NRC action, an incident at the plant or otherwise, could have a material adverse effect on KCP&L's results of operations, financial position and cash flows in the event KCP&L incurs higher replacement power and other costs that are not recovered through rates or insurance. If a long-term outage occurred, the state regulatory commissions could reduce rates by excluding the Wolf Creek investment from rate base. Wolf Creek was constructed prior to 1986 and the age of Wolf Creek increases the risk of unplanned outages and results in higher maintenance costs.

Ownership and operation of a nuclear generating unit exposes KCP&L to risks regarding decommissioning costs at the end of the unit's life. KCP&L contributes annually based on estimated decommissioning costs to a tax-qualified trust fund to be used to decommission Wolf Creek. The funding level assumes a projected level of return on trust assets. If the actual return on trust assets is below the projected level or actual decommissioning costs are higher

than estimated, KCP&L could be responsible for the balance of funds required and may not be allowed to recover the balance through rates.

KCP&L is also exposed to other risks associated with the ownership and operation of a nuclear generating unit, including, but not limited to, (i) potential liability associated with the potential harmful effects on the environment and human health resulting from the operation of a nuclear generating unit, (ii) the storage, handling, disposal and potential release (by accident, through third-party actions or otherwise) of radioactive materials and (iii) uncertainties with respect to contingencies and assessments if insurance coverage is inadequate. Under the structure for insurance among owners of nuclear generating units, KCP&L is also liable for potential retrospective premium assessments (subject to a cap) per incident at any commercial reactor in the country and losses in excess of insurance coverage.

The structure of the regional power market in which the Companies operate could have an adverse effect on the Companies' results of operations, financial position and cash flows.

In March 2014, the SPP launched its Integrated Marketplace. Similar to other RTO or ISO markets, this marketplace determines which generating units among market participants should run, within the operating constraints of a unit, at any given time for maximum cost-effectiveness. In the event that KCP&L's and GMO's generating units are not among the lowest cost generating units operating within the market, KCP&L and GMO could experience decreased levels of wholesale electricity sales.

A market for Transmission Congestion Rights (TCR) is also included as part of the Integrated Marketplace. TCRs are financial instruments used to hedge transmission congestion charges. Both KCP&L and GMO acquire TCRs for the purpose of hedging against transmission congestion charges. There is a risk that KCP&L and GMO could incorrectly model the amount of TCRs needed, or that the TCRs acquired could be ineffective in hedging against transmission congestion charges which could lead to increased purchased power costs.

The rules governing the various regional power markets may change from time to time and such changes could impact the Companies' costs and revenues. Because the manner in which RTO's or ISO's will evolve is unclear, the Companies are unable to assess fully the impact of these changes.

Litigation Risks:

The outcome of legal proceedings cannot be predicted. An adverse finding could have a material adverse effect on the Companies' results of operations, financial position and cash flows.

The Companies are party to various material litigation and regulatory matters arising out of their business operations. The ultimate outcome of these matters cannot presently be determined, nor, in many cases, can the liability that could potentially result from a negative outcome in each case be reasonably estimated. The liability that the Companies may ultimately incur with respect to any of these cases in the event of a negative outcome may be in excess of amounts currently reserved and insured against with respect to such matters.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Electric Utility Generation Resources

	Unit	Location	Year Completed	Estimated 2016 MW Capacity	Primary Fuel
Base Load	Iatan No. 2	Missouri	2010	482 [a]	Coal
	Wolf Creek	Kansas	1985	549 [a]	Nuclear
	Iatan No. 1	Missouri	1980	499 [a]	Coal
	La Cygne Nos. 1 and 2	Kansas	1973, 1977	699 [a]	Coal
	Hawthorn No. 5 [b]	Missouri	1969	564	Coal
	Montrose Nos. 2 and 3	Missouri	1960, 1964	340	Coal
Peak Load	West Gardner Nos. 1, 2, 3 and 4	Kansas	2003	311	Natural Gas
	Osawatomie	Kansas	2003	77	Natural Gas
	Hawthorn Nos. 6 and 9	Missouri	2000	235	Natural Gas
	Hawthorn No. 8	Missouri	2000	79	Natural Gas
	Hawthorn No. 7	Missouri	2000	78	Natural Gas
	Northeast Black Start Unit	Missouri	1985	2	Oil
	Northeast Nos. 17 and 18	Missouri	1977	105	Oil
	Northeast Nos. 13 and 14	Missouri	1976	95	Oil
	Northeast Nos. 15 and 16	Missouri	1975	106	Oil
	Northeast Nos. 11 and 12	Missouri	1972	93	Oil
Wind	Spearville 2 Wind Energy Facility [c]	Kansas	2010	15	Wind
	Spearville 1 Wind Energy Facility [d]	Kansas	2006	31	Wind
Total KCP&L				4,360	
Base Load	Iatan No. 2	Missouri	2010	159 [a]	Coal
	Iatan No. 1	Missouri	1980	128 [a]	Coal
	Jeffrey Energy Center Nos. 1, 2 and 3	Kansas	1978, 1980, 1983	172 [a]	Coal
	Sibley Nos. 1, 2 and 3	Missouri	1960, 1962, 1969	461	Coal
	Lake Road Nos. 2 and 4	Missouri	1957, 1967	115	Coal and Natural Gas
Peak Load	South Harper Nos. 1, 2 and 3	Missouri	2005	303	Natural Gas
	Crossroads Energy Center	Mississippi	2002	292	Natural Gas
	Ralph Green No. 3	Missouri	1981	71	Natural Gas
	Greenwood Nos. 1, 2, 3 and 4	Missouri	1975-1979	247	Natural Gas/Oil
	Lake Road No. 5	Missouri	1974	62	Natural Gas/Oil
	Lake Road Nos. 1 and 3	Missouri	1951, 1962	16	Natural Gas/Oil
	Lake Road Nos. 6 and 7	Missouri	1989, 1990	42	Oil
	Nevada	Missouri	1974	18	Oil
Total GMO				2,086	
Total Great Plains Energy				6,446	

[a] Share of a jointly owned unit.
[b] In 2001, a new boiler, air quality control equipment and an uprated turbine was placed in service at the Hawthorn Generating Station.
[c] The 48 MW Spearville 2 Wind Energy Facility's accredited capacity is 15 MW pursuant to SPP reliability standards.
[d] The 100.5 MW Spearville 1 Wind Energy Facility's accredited capacity is 31 MW pursuant to SPP reliability standards.

KCP&L owns 50% of La Cygne Nos. 1 and 2, 70% of Iatan No. 1, 55% of Iatan No. 2 and 47% of Wolf Creek. GMO owns 18% of each of Iatan Nos. 1 and 2 and 8% of Jeffrey Energy Center Nos. 1, 2 and 3.

Electric Utility Transmission and Distribution Resources
Electric utility's electric transmission system interconnects with systems of other utilities for reliability and to permit wholesale transactions with other electricity suppliers. Electric utility has approximately 3,600 circuit miles of transmission lines, 15,600 circuit miles of overhead distribution lines and 7,000 circuit miles of underground distribution lines in Missouri and Kansas. Electric utility has all material franchise rights necessary to sell electricity within its retail service territory. Electric utility's transmission and distribution systems are continuously monitored for adequacy to meet customer needs. Management believes the current systems are adequate to serve customers.

Electric Utility General
Electric utility's generating plants are located on property owned (or co-owned) by KCP&L or GMO, except the Spearville Wind Energy Facilities which are located on easements, and the Crossroads Energy Center and the South Harper Facility which are contractually controlled. Electric utility's service centers, electric substations and a portion of its transmission and distribution systems are located on property owned or leased by electric utility. Electric utility's transmission and distribution systems are for the most part located above or underneath highways, streets, other public places or property owned by others. Electric utility believes that it has satisfactory rights to use those places or properties in the form of permits, grants, easements, licenses or franchise rights; however, it has not necessarily undertaken efforts to examine the underlying title to the land upon which the rights rest. Great Plains Energy's and KCP&L's headquarters are located in leased office space.

Substantially all of the fixed property and franchises of KCP&L, which consist principally of electric generating stations, electric transmission and distribution lines and systems, and buildings (subject to exceptions, reservations and releases), are subject to a General Mortgage Indenture and Deed of Trust dated as of December 1, 1986, as supplemented. Mortgage bonds totaling $510.5 million were outstanding at December 31, 2015.

Substantially all of the fixed property and franchises of GMO's St. Joseph Light & Power division is subject to a General Mortgage Indenture and Deed of Trust dated as of April 1, 1946, as supplemented. Mortgage bonds totaling $6.8 million were outstanding at December 31, 2015.

ITEM 3. LEGAL PROCEEDINGS

Other Proceedings
The Companies are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 5, 14 and 15 to the consolidated financial statements. Such information is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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

GREAT PLAINS ENERGY

Great Plains Energy's common stock is listed on the New York Stock Exchange under the symbol "GXP". At February 23, 2016, Great Plains Energy's common stock was held by 15,791 shareholders of record. Information relating to market prices and cash dividends on Great Plains Energy's common stock is set forth in the following table:

	Common Stock Price Range [a]				Common Stock Dividends Declared		
	2015		2014				
Quarter	High	Low	High	Low	2016	2015	2014
First	$ 30.06	$ 25.80	$ 27.04	$ 23.85	$0.2625 [b]	$ 0.245	$ 0.23
Second	27.52	24.16	27.22	25.02		0.245	0.23
Third	27.35	24.21	26.80	24.17		0.245	0.23
Fourth	28.02	25.74	29.38	24.21		0.2625	0.245

[a] Based on closing stock prices.
[b] Declared February 10, 2016, and payable March 21, 2016, to shareholders of record as of February 29, 2016.

Dividend Restrictions

For information regarding dividend restrictions, see Note 12 to the consolidated financial statements.

Purchases of Equity Securities

Great Plains Energy had no purchases of its equity securities during the three months ended December 31, 2015.

KCP&L

KCP&L is a wholly owned subsidiary of Great Plains Energy, which holds the one share of issued and outstanding KCP&L common stock.

Dividend Restrictions

For information regarding dividend restrictions, see Note 12 to the consolidated financial statements.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31	2015	2014 [a]	2013 [a]	2012 [a]	2011 [a]
Great Plains Energy	(dollars in millions except per share amounts)				
Operating revenues	$ 2,502	$ 2,568	$ 2,446	$ 2,310	$ 2,318
Net income attributable to Great Plains Energy	$ 213	$ 243	$ 250	$ 200	$ 174
Basic earnings per common share	$ 1.37	$ 1.57	$ 1.62	$ 1.36	$ 1.27
Diluted earnings per common share	$ 1.37	$ 1.57	$ 1.62	$ 1.35	$ 1.25
Total assets at year end [a]	$ 10,739	$ 10,453	$ 9,770	$ 9,626	$ 9,096
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities) [a]	$ 3,746	$ 3,481	$ 3,492	$ 2,999	$ 3,522
Cash dividends per common share	$ 0.9975	$ 0.935	$ 0.8825	$ 0.855	$ 0.835
SEC ratio of earnings to fixed charges	2.58	2.72	2.75	2.31	2.03
KCP&L					
Operating revenues	$ 1,714	$ 1,731	$ 1,671	$ 1,580	$ 1,558
Net income	$ 153	$ 162	$ 169	$ 142	$ 136
Total assets at year end [a]	$ 7,815	$ 7,495	$ 6,821	$ 6,689	$ 6,276
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities) [a]	$ 2,563	$ 2,297	$ 2,294	$ 1,887	$ 1,899
SEC ratio of earnings to fixed charges	2.57	2.69	2.76	2.58	2.52

[a] Adjusted for adoption of Accounting Standards Update (ASU) No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. See Note 1 to the consolidated financial statements under the heading New Accounting Standards for additional information.

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

GREAT PLAINS ENERGY INCORPORATED

EXECUTIVE SUMMARY

Description of Business

Great Plains Energy is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries.

Great Plains Energy's sole reportable business segment is electric utility. Electric utility consists of KCP&L, a regulated utility, GMO's regulated utility operations, which include its Missouri Public Service and St. Joseph Light & Power divisions, and GMO Receivables Company. Electric utility has approximately 6,400 MWs of owned generating capacity and engages in the generation, transmission, distribution and sale of electricity to approximately 846,100 customers in the states of Missouri and Kansas. Electric utility's retail electricity rates are comparable to the national average of investor-owned utilities.

Great Plains Energy's corporate and other activities not included in the sole reportable business segment includes GMO activity other than its regulated utility operations, GPETHC and unallocated corporate charges.

2015 Earnings Overview

Great Plains Energy's 2015 earnings available for common shareholders decreased to $211.4 million or $1.37 per share from $241.2 million or $1.57 per share in 2014 driven by:

- a $53.4 million increase in gross margin driven by new retail rates, an increase in weather-normalized retail demand, recovery of program costs for energy efficiency programs under the Missouri Energy Efficiency Investment Act (MEEIA) and recovery of renewable energy costs under the Missouri Renewable Energy Standard Rate Adjustment Mechanism (RESRAM), both of which have a direct offset in utility operating and maintenance expense; partially offset by milder weather;
- a $22.9 million increase in utility operating and maintenance expenses primarily driven by an increase in program costs for energy efficiency programs under MEEIA and amortization of deferred renewable energy costs under RESRAM, both of which have a direct offset in revenue, partially offset by a decrease in Wolf Creek operating and maintenance expenses primarily due to decreased refueling outage amortization and a planned mid-cycle maintenance outage in 2014;
- a $24.4 million increase in depreciation and amortization expense driven by capital additions;
- an $8.6 million increase in general taxes driven by higher property taxes;
- a $13.3 million decrease in non-operating income driven by a decrease in the equity component of Allowance for Funds Used During Construction (AFUDC);
- a $10.8 million increase in interest charges primarily due to lower interest expense in 2014 related to the release of uncertain tax positions and a decrease in the debt component of AFUDC; and
- a $7.0 million increase in income tax expense primarily driven by income tax benefits in 2014 related to the release of uncertain tax positions partially offset by decreased pre-tax income.

Gross margin is a financial measure that is not calculated in accordance with Generally Accepted Accounting Principles (GAAP). See the explanation of gross margin and the reconciliation to GAAP operating revenues under Great Plains Energy's Results of Operations for further information.

For additional information regarding the change in earnings, refer to the Great Plains Energy Results of Operations and the Electric Utility Results of Operations sections within this MD&A.

Regulatory Proceedings
See Note 5 to the consolidated financial statements for information regarding regulatory proceedings.

Impact of Recently Issued Accounting Standards
See Note 1 to the consolidated financial statements for information regarding the impact of recently issued accounting standards.

Wolf Creek Mid-Cycle Maintenance Outage and Refueling Outage
Wolf Creek's latest refueling outage began on February 28, 2015, and ended on May 3, 2015. Wolf Creek had a mid-cycle maintenance outage that began on March 8, 2014, and ended on May 13, 2014. Wolf Creek's next refueling outage is planned to begin in the third quarter of 2016.

ENVIRONMENTAL MATTERS

See Note 14 to the consolidated financial statements for information regarding environmental matters.

RELATED PARTY TRANSACTIONS

See Note 17 to the consolidated financial statements for information regarding related party transactions.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures. Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate or different estimates that could have been used could have a material impact on Great Plains

Energy's results of operations and financial position. Management has identified the following accounting policies as critical to the understanding of Great Plains Energy's results of operations and financial position. Management has discussed the development and selection of these critical accounting policies with the Audit Committee of the Great Plains Energy Board of Directors (Board).

Pensions

Great Plains Energy incurs significant costs in providing non-contributory defined pension benefits. The costs are measured using actuarial valuations that are dependent upon numerous factors derived from actual plan experience and assumptions of future plan experience.

Pension costs are impacted by actual employee demographics (including age, life expectancies, compensation levels and employment periods), earnings on plan assets, the level of contributions made to the plan, and plan amendments. In addition, pension costs are also affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

The assumed rate of return on plan assets was developed based on the weighted-average of long-term returns forecast for the expected portfolio mix of investments held by the plan. The assumed discount rate was selected based on the prevailing market rate of fixed income debt instruments with maturities matching the expected timing of the benefit obligation. These assumptions, updated annually at the measurement date, are based on management's best estimates and judgment; however, material changes may occur if these assumptions differ from actual events. See Note 8 to the consolidated financial statements for information regarding the assumptions used to determine benefit obligations and net costs.

The following table reflects the sensitivities associated with a 0.5% increase or a 0.5% decrease in key actuarial assumptions. Each sensitivity reflects the impact of the change based on a change in that assumption only.

Actuarial assumption	Change in Assumption	Impact on Projected Benefit Obligation	Impact on 2015 Pension Expense
		(millions)	
Discount rate	0.5% increase	$ (78.5)	$ (5.9)
Rate of return on plan assets	0.5% increase	—	(3.4)
Discount rate	0.5% decrease	85.1	6.1
Rate of return on plan assets	0.5% decrease	—	3.4

Pension expense for KCP&L and GMO is recorded in accordance with rate orders from the MPSC and KCC. The orders allow the difference between pension costs under GAAP and pension costs for ratemaking to be recorded as a regulatory asset or liability with future ratemaking recovery or refunds, as appropriate.

In 2015, Great Plains Energy's pension expense was $96.1 million under GAAP and $86.3 million for ratemaking. The impact on 2015 pension expense in the table above reflects the impact on GAAP pension costs. Under the Companies' rate agreements, any increase or decrease in GAAP pension expense would be deferred in a regulatory asset or liability for future ratemaking treatment. See Note 8 to the consolidated financial statements for additional information regarding the accounting for pensions.

Market conditions and interest rates significantly affect the future assets and liabilities of the plan. It is difficult to predict future pension costs, changes in pension liability and cash funding requirements due to the inherent uncertainty of market conditions.

Regulatory Assets and Liabilities

The Company has recorded assets and liabilities on its consolidated balance sheets resulting from the effects of the ratemaking process, which would not otherwise be recorded under GAAP. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent future reductions in revenues or refunds to customers.

Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC in electric utility's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to electric utility; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. Electric utility's continued ability to meet the criteria for recording regulatory assets and liabilities may be affected in the future by restructuring and deregulation in the electric industry or changes in accounting rules. In the event that the criteria no longer applied to all or a portion of electric utility's operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism were provided. Additionally, these factors could result in an impairment on utility plant assets. See Note 5 to the consolidated financial statements for additional information.

Impairments of Assets, Intangible Assets and Goodwill

Long-lived assets and intangible assets subject to amortization are required to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under GAAP.

Accounting rules require goodwill to be tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The goodwill impairment test is a two step process. The first step compares the fair value of a reporting unit to its carrying amount, including goodwill, to identify potential impairment. If the carrying amount exceeds the fair value of the reporting unit, the second step of the test is performed, consisting of assignment of the reporting unit's fair value to its assets and liabilities to determine an implied fair value of goodwill, which is compared to the carrying amount of goodwill to determine the impairment loss, if any, to be recognized in the financial statements. Great Plains Energy's regulated electric utility operations are considered one reporting unit for assessment of impairment, as they are included within the same operating segment and have similar economic characteristics.

The annual impairment test for the $169.0 million of GMO acquisition goodwill was conducted on September 1, 2015. Fair value of the reporting unit substantially exceeded the carrying amount, including goodwill; therefore, there was no impairment of goodwill.

The determination of fair value of the reporting unit consisted of two valuation techniques: an income approach consisting of a discounted cash flow analysis and a market approach consisting of a determination of reporting unit invested capital using market multiples derived from the historical revenue, earnings before interest, income taxes, depreciation and amortization (EBITDA), net utility asset values and market prices of stock of peer companies. The results of the two techniques were evaluated and weighted to determine a point within the range that management considered representative of fair value for the reporting unit, which involves a significant amount of management judgment.

The discounted cash flow analysis is most significantly impacted by two assumptions: estimated future cash flows and the discount rate applied to those cash flows. Management determined the appropriate discount rate to be based on the reporting unit's weighted average cost of capital (WACC). The WACC takes into account both the return on equity authorized by the MPSC and KCC and after-tax cost of debt. Estimated future cash flows are based on Great Plains Energy's internal business plan, which assumes the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of return on equity, anticipated earnings/returns related to future capital investments, continued recovery of cost of service and the renewal of certain contracts. Management also makes assumptions regarding the run rate of operations, maintenance and general and administrative costs based on the expected outcome of the aforementioned events. Should the actual outcome of some or all of these assumptions

differ significantly from the current assumptions, revisions to current cash flow assumptions could cause the fair value of Great Plains Energy's reporting unit under the income approach to be significantly different in future periods and could result in a future impairment charge to goodwill.

The market approach analysis is most significantly impacted by management's selection of relevant peer companies as well as the determination of an appropriate control premium to be added to the calculated invested capital of the reporting unit, as control premiums associated with a controlling interest are not reflected in the quoted market price of a single share of stock. Management determined an appropriate control premium by using an average of control premiums for recent acquisitions in the industry. Changes in results of peer companies, selection of different peer companies and future acquisitions with significantly different control premiums could result in a significantly different fair value of Great Plains Energy's reporting unit.

Income Taxes

Income taxes are accounted for using the asset/liability approach. Deferred tax assets and liabilities are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, applying enacted statutory tax rates in effect for the year in which the differences are expected to reverse. Deferred investment tax credits are amortized ratably over the life of the related property. Deferred tax assets are also recorded for net operating losses, capital losses and tax credit carryforwards. The Company is required to estimate the amount of taxes payable or refundable for the current year and the deferred tax liabilities and assets for future tax consequences of events reflected in the Company's consolidated financial statements or tax returns. Actual results could differ from these estimates for a variety of reasons including changes in income tax laws, enacted tax rates and results of audits by taxing authorities. This process also requires management to make assessments regarding the timing and probability of the ultimate tax impact from which actual results may differ. The Company records valuation allowances on deferred tax assets if it is determined that it is more likely than not that the asset will not be realized. See Note 21 to the consolidated financial statements for additional information.

GREAT PLAINS ENERGY RESULTS OF OPERATIONS

The following table summarizes Great Plains Energy's comparative results of operations.

	2015	2014	2013
		(millions)	
Operating revenues	$ 2,502.2	$ 2,568.2	$ 2,446.3
Fuel	(421.4)	(489.2)	(539.5)
Purchased power	(187.3)	(253.3)	(125.9)
Transmission	(89.1)	(74.7)	(53.2)
Gross margin [(a)]	1,804.4	1,751.0	1,727.7
Other operating expenses	(943.9)	(910.5)	(868.8)
Depreciation and amortization	(330.4)	(306.0)	(289.7)
Operating income	530.1	534.5	569.2
Non-operating income and expenses	3.7	12.5	8.8
Interest charges	(199.3)	(188.5)	(198.4)
Income tax expense	(122.7)	(115.7)	(129.2)
Income (loss) from equity investments	1.2	—	(0.2)
Net income	213.0	242.8	250.2
Preferred dividends	(1.6)	(1.6)	(1.6)
Earnings available for common shareholders	$ 211.4	$ 241.2	$ 248.6

[(a)] Gross margin is a non-GAAP financial measure. See explanation of gross margin below.

2015 Compared to 2014

Great Plains Energy's 2015 earnings available for common shareholders decreased to $211.4 million or $1.37 per share from $241.2 million or $1.57 per share in 2014.

Electric utility's net income decreased $19.7 million in 2015 compared to 2014 primarily due to:

- a $53.4 million increase in gross margin driven by:
  - an estimated $36 million increase due to new retail rates for KCP&L in Missouri effective September 29, 2015, and in Kansas effective July 25, 2014 and October 1, 2015;
  - a $22.2 million increase for recovery of program costs for energy efficiency programs under MEEIA, which have a direct offset in utility operating and maintenance expense, primarily due to the implementation of KCP&L's MEEIA programs in August 2014;
  - a $7.2 million increase for recovery of renewable energy costs under RESRAM, which have a direct offset in utility operating and maintenance expense;
  - an estimated $6 million increase from weather-normalized retail demand;
  - an estimated $20 million increase in other margin items including a change in customer mix, lower fuel and purchased power expenses that are not included in fuel recovery mechanisms and an increase in transmission costs recovered through the transmission delivery charge rider that began in the fourth quarter of 2015;
  - an estimated $19 million decrease due to lower wholesale margins partially offset by an estimated $14 million due to lower fuel and purchased power expense at KCP&L in Missouri, where there was no fuel recovery mechanism prior to September 29, 2015;
  - an estimated $9 million decrease due to higher transmission expense; and
  - an estimated $24 million decrease due to weather driven by a 19% decrease in heating degree days in 2015 and a 15% decrease in cooling degree days in the second quarter of 2015 partially offset by an 18% increase in cooling degree days in the third quarter of 2015.
- a $33.8 million increase in other operating expenses primarily due to:
  - a $22.2 million increase in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue, primarily due to the implementation of KCP&L's MEEIA programs in August 2014;
  - a $7.2 million increase in amortization of deferred renewable energy costs under RESRAM, which have a direct offset in revenue;
  - an $8.7 million increase in general taxes driven by higher property taxes; and
  - a $10.0 million decrease in Wolf Creek operating and maintenance expenses primarily due to decreased refueling outage amortization of $3.6 million and $8.7 million from a planned mid-cycle maintenance outage in 2014.
- a $24.4 million increase in depreciation and amortization expense due to capital additions;
- an $11.8 million decrease in non-operating income and expenses driven by a $13.2 million decrease in the equity component of AFUDC primarily due to a lower average construction work in progress in 2015 due to environmental upgrades at KCP&L's La Cygne Station being placed into service;
- a $7.9 million increase in interest charges primarily due to a $7.2 million decrease in the debt component of AFUDC; and
- a $4.8 million decrease in income tax expense primarily driven by decreased pre-tax income.

Great Plains Energy's corporate and other activities loss increased $10.1 million in 2015 compared to 2014 primarily due to the release of uncertain tax positions related to former GMO non-regulated operations in the third quarter of 2014 which resulted in:

- $2.1 million lower after-tax interest expense in 2014; and
- $6.1 million of income tax benefits in 2014.

2014 Compared to 2013

Great Plains Energy's 2014 earnings available for common shareholders decreased to $241.2 million or $1.57 per share from $248.6 million or $1.62 per share in 2013.

Electric utility's net income decreased $13.6 million in 2014 compared to 2013 primarily due to:

- a $23.3 million increase in gross margin driven by:
    - an estimated $14 million increase from new retail rates in Missouri effective January 26, 2013 and in Kansas effective July 25, 2014;
    - a $16.0 million increase from energy efficiency programs under MEEIA consisting of $12.4 million for recovery of program costs, which have a direct offset in utility operating and maintenance expense, and $3.6 million for recovery of throughput disincentive; and
    - an estimated $4 million decrease due to unfavorable weather driven by a 6% decrease in cooling degree days;
- a $40.8 million increase in other operating expenses primarily due to:
    - a $6.0 million increase in Wolf Creek operating and maintenance expenses due to $8.7 million from a planned mid-cycle outage that began in March 2014 and concluded in May 2014, increased amortization of $3.4 million from a planned refueling outage that began in February 2013 and ended in April 2013, where costs are deferred and amortized between refueling outages, partially offset by $6.1 million of other decreases in operating and maintenance expenses;
    - a $12.4 million increase in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue;
    - an $8.3 million increase in transmission and distribution operating and maintenance expenses; and
    - a $10.4 million increase in general taxes due to increased property taxes;
- a $16.3 million increase in depreciation and amortization expense due to capital additions;
- a $7.5 million decrease in interest expense primarily due to:
    - a $1.6 million decrease from the remarketing of KCP&L's Series 1992, 1993A, 2007B Environmental Improvement Revenue Refunding (EIRR) bonds in April 2013 and Series 2008 EIRR bonds in July 2013 at lower interest rates;
    - a $2.3 million decrease in borrowing costs for short-term debt primarily driven by lower average commercial paper balances and interest rates in 2014 at GMO, as well as lower borrowing fees under KCP&L's and GMO's revolving credit facilities in 2014; and
    - a $1.2 million increase in the debt component of AFUDC resulting from a higher average construction work in progress balance in 2014 primarily due to environmental upgrades at KCP&L's La Cygne Station; and
- a $9.8 million decrease in income tax expense primarily due to decreased pre-tax income.

Great Plains Energy's corporate and other activities loss decreased $6.2 million in 2014 compared to 2013 primarily due to the release of uncertain tax positions related to former GMO non-regulated operations in the third quarter of 2014 which resulted in:

- a $2.1 million decrease in after-tax interest expense; and
- $6.1 million of income tax benefits.

Gross Margin

Gross margin is a financial measure that is not calculated in accordance with GAAP. Gross margin, as used by Great Plains Energy and KCP&L, is defined as operating revenues less fuel, purchased power and transmission. Expenses for fuel, purchased power and certain transmission costs, offset by wholesale sales margin, are subject to recovery through cost adjustment mechanisms, except for KCP&L's Missouri retail operations prior to September 29, 2015, when a cost adjustment mechanism was approved. As a result, operating revenues increase or decrease in relation to a significant portion of these expenses. Management believes that gross margin provides a more meaningful basis for evaluating electric utility's operations across periods than operating revenues because gross margin excludes the revenue effect of fluctuations in these expenses. Gross margin is used internally to measure performance against budget and in reports for management and the Board. The Companies' definition of gross margin may differ from similar terms used by other companies.

ELECTRIC UTILITY RESULTS OF OPERATIONS

The following table summarizes the electric utility segment results of operations.

	2015	2014	2013
		(millions)	
Operating revenues	$ 2,502.2	$ 2,568.2	$ 2,446.3
Fuel	(421.4)	(489.2)	(539.5)
Purchased power	(187.3)	(253.3)	(125.9)
Transmission	(89.1)	(74.7)	(53.2)
Gross margin [(a)]	1,804.4	1,751.0	1,727.7
Other operating expenses	(940.2)	(906.4)	(865.6)
Depreciation and amortization	(330.4)	(306.0)	(289.7)
Operating income	533.8	538.6	572.4
Non-operating income and expenses	1.7	13.5	10.6
Interest charges	(190.9)	(183.0)	(190.5)
Income tax expense	(120.8)	(125.6)	(135.4)
Net income	$ 223.8	$ 243.5	$ 257.1

[(a)] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

Electric Utility Gross Margin and MWh Sales

The following tables summarize electric utility's gross margin and MWhs sold:

Gross Margin [a]	2015	% Change[c]	2014	% Change[c]	2013
Retail revenues			(millions)		
Residential	$ 1,003.4	—	$ 999.0	—	$ 1,000.6
Commercial	997.4	3	970.0	1	963.3
Industrial	222.1	2	217.4	3	211.7
Other retail revenues	20.3	1	20.1	(2)	20.5
Kansas property tax surcharge	0.7	(66)	2.1	N/M	(1.3)
Energy efficiency (MEEIA)[b]	51.5	81	28.5	N/M	12.5
Fuel recovery mechanisms	6.0	(90)	57.7	N/M	21.9
Total retail	2,301.4	—	2,294.8	3	2,229.2
Wholesale revenues	147.1	(34)	222.6	32	168.8
Other revenues	53.7	6	50.8	5	48.3
Operating revenues	2,502.2	(3)	2,568.2	5	2,446.3
Fuel	(421.4)	(14)	(489.2)	(9)	(539.5)
Purchased power	(187.3)	(26)	(253.3)	101	(125.9)
Transmission	(89.1)	19	(74.7)	40	(53.2)
Gross margin	$ 1,804.4	3	$ 1,751.0	1	$ 1,727.7

[a] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

[b] Consists of recovery of program costs of $42.9 million, $20.7 million and $8.3 million for 2015, 2014 and 2013, respectively, that have a direct offset in utility operating and maintenance expenses and recovery of throughput disincentive of $8.6 million, $7.8 million and $4.2 million for 2015, 2014 and 2013, respectively.

[c] N/M - not meaningful

MWh Sales	2015	% Change	2014	% Change	2013
Retail MWh sales			(thousands)		
Residential	8,585	(4)	8,971	—	8,999
Commercial	10,777	(1)	10,827	—	10,782
Industrial	3,191	—	3,200	2	3,132
Other retail MWh sales	116	(1)	117	(2)	118
Total retail	22,669	(2)	23,115	—	23,031
Wholesale MWh sales	6,512	(14)	7,587	21	6,283
Total MWh sales	29,181	(5)	30,702	5	29,314

Electric utility's residential customers' usage is significantly affected by weather. Bulk power sales, the major component of wholesale sales, vary with system requirements, generating unit availability, transmission availability, fuel costs, and requirements of other electric systems. Electric utility's revenues contain certain recovery mechanisms as follows:

- KCP&L's Kansas retail rates contain an Energy Cost Adjustment (ECA) tariff. The ECA tariff reflects the projected annual amounts of fuel, purchased power, emission allowances and asset-based off-system sales margin. These projected amounts are subject to quarterly re-forecasts. Any difference between the ECA revenue collected and the actual ECA amounts for a given year (which may be positive or negative) is recorded as an increase to or reduction of retail revenues and deferred as a regulatory asset or liability to be recovered from or refunded to Kansas retail customers over twelve months beginning April 1 of the succeeding year.
- KCP&L's Kansas retail rates contain a Transmission Delivery Charge (TDC) rider. The TDC tariff reflects a mixture of historical and projected costs related to retail transmission, certain RTO fees and transmission

operating and maintenance expense. The projected amounts are subject to an annual true-up with a twelve month recovery period. The TDC is recorded as an increase to or reduction of retail revenues and deferred as a regulatory asset or liability to be recovered from or refunded to KCP&L's Kansas electric retail customers. The TDC became effective in conjunction with new retail rates on October 1, 2015.

- KCP&L's Missouri retail rates contain a Fuel Adjustment Clause (FAC) tariff under which 95% of the difference between actual fuel cost, purchased power costs, certain transmission costs and off-system sales margin and the amount provided in base rates for these costs is passed along to KCP&L's customers. The FAC cycle consists of an accumulation period of six months beginning in January and July with FAC rate approval requested every six months for a twelve month recovery period. The FAC is recorded as an increase to or reduction of retail revenues and deferred as a regulatory asset or liability to be recovered from or refunded to KCP&L's electric retail customers. The FAC became effective in conjunction with new retail rates on September 29, 2015.
- GMO's electric retail rates contain a FAC tariff under which 95% of the difference between actual fuel cost, purchased power costs, certain transmission costs and off-system sales margin and the amount provided in base rates for these costs is passed along to GMO's customers. The FAC cycle consists of an accumulation period of six months beginning in June and December with FAC rate approval requested every six months for a twelve month recovery period. The FAC is recorded as an increase to or reduction of retail revenues and deferred as a regulatory asset or liability to be recovered from or refunded to GMO's electric retail customers.
- GMO's steam rates contain a Quarterly Cost Adjustment (QCA) under which 85% of the difference between actual fuel costs and base fuel costs is passed along to GMO's steam customers. The QCA is recorded as an increase to or reduction of other revenues and deferred as a regulatory asset or liability to be recovered from or refunded to GMO's steam customers.

Both KCP&L and GMO offer energy efficiency and demand side management programs to their Missouri retail customers under MEEIA and recover both program costs and throughput disincentive in retail rates. KCP&L recovers these items through a rider mechanism, with the difference between the amount collected and the actual program costs and throughput disincentive recorded as an increase to or reduction of retail revenues and is deferred as a regulatory asset or liability to be recovered from or refunded to KCP&L's Missouri retail customers. GMO recovers these items through base rates, with the difference between the amount collected and the actual program costs and throughput disincentive to be included as part of future GMO rate case proceedings.

Electric utility's gross margin increased $53.4 million in 2015 compared to 2014 primarily due to:

- an estimated $36 million increase due to new retail rates for KCP&L in Missouri effective September 29, 2015, and in Kansas effective July 25, 2014 and October 1, 2015;
- a $22.2 million increase for recovery of program costs for energy efficiency programs under MEEIA, which have a direct offset in utility operating and maintenance expense, primarily due to the implementation of KCP&L's MEEIA programs in August 2014;
- a $7.2 million increase for recovery of renewable energy costs under RESRAM, which have a direct offset in utility operating and maintenance expense;
- an estimated $6 million increase from weather-normalized retail demand;
- an estimated $20 million increase in other margin items including a change in customer mix, lower fuel and purchased power expenses that are not included in fuel recovery mechanisms and an increase in transmission costs recovered through the transmission delivery charge rider that began in the fourth quarter of 2015;
- an estimated $19 million decrease due to lower wholesale margins partially offset by an estimated $14 million due to lower fuel and purchased power expense at KCP&L in Missouri, where there was no fuel recovery mechanism prior to September 29, 2015;
- an estimated $9 million decrease due to higher transmission expense; and

- an estimated $24 million decrease due to weather driven by a 19% decrease in heating degree days in 2015 and a 15% decrease in cooling degree days in the second quarter of 2015 partially offset by an 18% increase in cooling degree days in the third quarter of 2015.

Electric utility's gross margin increased $23.3 million in 2014 compared to 2013 primarily due to:

- an estimated $14 million increase from new retail rates in Missouri effective January 26, 2013 and in Kansas effective July 25, 2014;
- a $16.0 million increase from energy efficiency programs under MEEIA consisting of $12.4 million for recovery of program costs, which have a direct offset in utility operating and maintenance expense, and $3.6 million for recovery of throughput disincentive; and
- an estimated $4 million decrease due to unfavorable weather driven by a 6% decrease in cooling degree days.

The following table provides cooling degree days (CDD) and heating degree days (HDD) for the last three years at the Kansas City International Airport. CDD and HDD are used to reflect the demand for energy to cool or heat homes and buildings.

	2015	% Change	2014	% Change	2013
CDD	1,370	8	1,266	(6)	1,345
HDD	4,578	(19)	5,666	2	5,561

Electric Utility Other Operating Expenses *(including utility operating and maintenance expenses, general taxes and other)*

Electric utility's other operating expenses increased $33.8 million in 2015 compared to 2014 primarily due to:

- a $22.2 million increase in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue, primarily due to the implementation of KCP&L's MEEIA programs in August 2014;
- a $7.2 million increase in amortization of deferred renewable energy costs under RESRAM, which have a direct offset in revenue;
- an $8.7 million increase in general taxes driven by higher property taxes; and
- a $10.0 million decrease in Wolf Creek operating and maintenance expenses primarily due to decreased refueling outage amortization of $3.6 million and $8.7 million from a planned mid-cycle maintenance outage in 2014.

Electric utility's other operating expenses increased $40.8 million in 2014 compared to 2013 primarily due to:

- a $6.0 million increase in Wolf Creek operating and maintenance expenses due to $8.7 million from a planned mid-cycle outage that began in March 2014 and concluded in May 2014, increased amortization of $3.4 million from a planned refueling outage that began in February 2013 and ended in April 2013, where costs are deferred and amortized between refueling outages, partially offset by $6.1 million of other decreases in operating and maintenance expenses;
- a $12.4 million increase in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue;
- an $8.3 million increase in transmission and distribution operating and maintenance expenses; and
- a $10.4 million increase in general taxes due to increased property taxes.

Electric Utility Depreciation and Amortization
Electric utility's depreciation and amortization expense increased $24.4 million in 2015 compared to 2014 due to capital additions. Electric utility's depreciation and amortization expense increased $16.3 million in 2014 compared to 2013 due to capital additions.

Electric Utility Non-Operating Income and Expenses
Electric utility's non-operating income and expenses decreased $11.8 million in 2015 compared to 2014 primarily due to a $13.2 million decrease in the equity component of AFUDC primarily due to a lower average construction work in progress in 2015 due to environmental upgrades at KCP&L's La Cygne Station being placed into service.

Electric Utility Interest Charges
Electric utility's interest charges increased $7.9 million in 2015 compared to 2014 primarily due to a $7.2 million decrease in in the equity component of AFUDC primarily due to a lower average construction work in progress in 2015 due to environmental upgrades at KCP&L's La Cygne Station being placed into service.

Electric utility's interest charges decreased $7.5 million in 2014 compared to 2013 primarily due to:

- a $1.6 million decrease from the remarketing of KCP&L's Series 1992, 1993A, 2007B EIRR bonds in April 2013 and Series 2008 EIRR bonds in July 2013 at lower interest rates;
- a $2.3 million decrease in borrowing costs for short-term debt primarily driven by lower average commercial paper balances and interest rates in 2014 at GMO, as well as lower borrowing fees under KCP&L's and GMO's revolving credit facilities in 2014; and
- a $1.2 million increase in the debt component of AFUDC resulting from a higher average construction work in progress balance in 2014 primarily due to environmental upgrades at KCP&L's La Cygne Station.

Electric Utility Income Tax Expense
Electric utility's income tax expense decreased $4.8 million in 2015 compared to 2014 primarily due to decreased pre-tax income. Electric utility's income tax expense decreased $9.8 million in 2014 compared to 2013 primarily due to decreased pre-tax income.

GREAT PLAINS ENERGY SIGNIFICANT BALANCE SHEET CHANGES
(December 31, 2015 compared to December 31, 2014)

- Great Plains Energy's fuel inventories, at average cost increased $28.3 million primarily due to an increase in coal inventories primarily due to coal plant maintenance outages.
- Great Plains Energy's deferred income taxes - current asset decreased $78.1 million due to the adoption of ASU 2015-17, *Balance Sheet Classification of Deferred Taxes*, requiring that deferred tax assets and liabilities be classified as noncurrent on the balance sheet.
- Great Plains Energy's net utility plant in service increased $945.8 million and construction work in progress decreased $552.1 million primarily due to environmental upgrades at KCP&L's La Cygne Station being placed into service.
- Great Plains Energy's commercial paper decreased $134.3 million primarily due to repayment with a portion of the proceeds from KCP&L's August 2015 issuance of $350.0 million of 3.65% Senior Notes partially offset by additional borrowings for general corporate purposes.
- Great Plains Energy's current maturities of long-term debt decreased $14.0 million due to the repayment of KCP&L's $14.0 million secured Series 2005 EIRR bonds at maturity in March 2015.
- Great Plains Energy's asset retirement obligations increased $80.0 million primarily due to new asset retirement obligations related to CCR regulations. See Note 7 to the consolidated financial statements for additional information.

- Great Plains Energy's long-term debt increased $279.4 million due to the August 2015 issuance, at a discount, of KCP&L's $350.0 million of 3.65% Senior Notes partially offset by the September 2015 purchase in lieu of redemption of $71.9 million of KCP&L's EIRR bonds.

CAPITAL REQUIREMENTS AND LIQUIDITY

Great Plains Energy operates through its subsidiaries and has no material assets other than the stock of its subsidiaries. Great Plains Energy's ability to make payments on its debt securities and its ability to pay dividends is dependent on its receipt of dividends or other distributions from its subsidiaries, proceeds from the issuance of its securities and borrowing under its revolving credit facility.

Great Plains Energy's capital requirements are principally comprised of debt maturities and electric utility's construction and other capital expenditures. These items as well as additional cash and capital requirements are discussed below.

Great Plains Energy's liquid resources at December 31, 2015, consisted of $11.3 million of cash and cash equivalents on hand and $1,010.6 million of available borrowing capacity from unused bank lines of credit and receivable sale agreements. The available borrowing capacity consisted of $189.8 million from Great Plains Energy's revolving credit facility, $417.0 million from KCP&L's credit facilities and $403.8 million from GMO's credit facilities. See Notes 3 and 10 to the consolidated financial statements for more information regarding the receivable sale agreements and revolving credit facilities, respectively. Generally, Great Plains Energy uses these liquid resources to meet its day-to-day cash flow requirements, and from time to time issues equity and/or long-term debt to repay short-term debt or increase cash balances.

Great Plains Energy intends to meet day-to-day cash flow requirements including interest payments, retirement of maturing debt, construction requirements, dividends and pension benefit plan funding requirements with a combination of internally generated funds and proceeds from short-term debt. From time to time, Great Plains Energy issues equity and/or long-term debt to repay short-term debt or increase cash balances. Great Plains Energy's intention to meet a portion of these requirements with internally generated funds may be impacted by the effect of inflation on operating expenses, the level of MWh sales, regulatory actions, compliance with environmental regulations and the availability of generating units. In addition, Great Plains Energy may issue equity, equity-linked securities and/or debt to finance growth.

Cash Flows from Operating Activities

Great Plains Energy generated positive cash flows from operating activities for the periods presented. The $54.9 million increase in cash flows from operating activities for Great Plains Energy in 2015 compared to 2014 was primarily due to a $34.2 million increase driven by a decrease in solar rebates paid to customers and an increase in the recovery of costs subject to fuel recovery mechanisms of $76.0 million, partially offset by a decrease in net income of $29.8 million and a decrease driven by deferred refueling outage costs of $23.7 million. Other changes in working capital are detailed in Note 2 to the consolidated financial statements. The individual components of working capital vary with normal business cycles and operations.

The $78.6 million decrease in cash flows from operating activities for Great Plains Energy in 2014 compared to 2013 was primarily due to a $32.4 million decrease driven by changes in coal inventory levels, a $27.2 million decrease driven by the under recovery of costs subject to fuel recovery mechanisms where deferrals have exceeded recoveries and a $10.7 million decrease driven by an increase in solar rebates paid to customers.

Cash Flows from Investing Activities

Great Plains Energy's cash used for investing activities varies with the timing of utility capital expenditures and purchases of investments and nonutility property. Investing activities are offset by proceeds from the sale of properties and insurance recoveries.

Great Plains Energy's utility capital expenditures decreased $96.6 million in 2015 compared to 2014 primarily due to a decrease in cash utility capital expenditures related to environmental upgrades at KCP&L's La Cygne Station.

Great Plains Energy's utility capital expenditures increased $104.7 million in 2014 compared to 2013 primarily due to an increase in cash utility capital expenditures related to infrastructure and system improvements at KCP&L offset by a decrease in expenditures related to environmental upgrades at KCP&L's La Cygne Station.

In January 2014, KCP&L and GMO completed the sale of two SPP-approved regional transmission projects, at cost, to Transource Missouri, LLC for cash proceeds of $37.7 million.

Cash Flows from Financing Activities

Great Plains Energy's cash flows from financing activities in 2015 reflect KCP&L's issuance, at a discount, of $350.0 million of 3.65% Senior Notes that mature in 2025, with the proceeds used to purchase in lieu of redemption $71.9 million of EIRR bonds and repay short-term borrowings.

Great Plains Energy's cash flows from financing activities in 2014 reflect increased short-term borrowings at KCP&L primarily driven by capital expenditures and pension funding contributions.

Great Plains Energy's cash flows from financing activities in 2013 reflect KCP&L's issuance, at a discount, of $300.0 million of 3.15% Senior Notes that mature in 2023 and the remarketing of $112.8 million of EIRR bonds previously held by KCP&L, with the proceeds used to repay short-term borrowings. In August 2013, GMO issued $350.0 million of senior notes and used the proceeds to repay a $248.7 million intercompany loan from Great Plains Energy and repay short-term borrowings. Great Plains Energy used the proceeds from GMO to repay its $250.0 million 2.75% Senior Notes that matured in August 2013.

Impact of Credit Ratings on Liquidity

The ratings of Great Plains Energy's, KCP&L's and GMO's securities by the credit rating agencies impact their liquidity, including the cost of borrowings under their revolving credit agreements and in the capital markets. The Companies view maintenance of strong credit ratings as extremely important to their access to and cost of debt financing and to that end maintain an active and ongoing dialogue with the agencies with respect to results of operations, financial position and future prospects. While a decrease in these credit ratings would not cause any acceleration of Great Plains Energy's, KCP&L's or GMO's debt, it could increase interest charges under Great Plains Energy's 6.875% Senior Notes due 2017 or Great Plains Energy's, KCP&L's and GMO's revolving credit agreements. A decrease in credit ratings could also have, among other things, an adverse impact, which could be material, on Great Plains Energy's, KCP&L's and GMO's access to capital, the cost of funds, the ability to recover actual interest costs in state regulatory proceedings, the type and amounts of collateral required under supply agreements and Great Plains Energy's ability to provide credit support for its subsidiaries.

As of February 24, 2016, the major credit rating agencies rated Great Plains Energy's, KCP&L's and GMO's securities as detailed in the following table.

	Moody's Investors Service	Standard & Poor's
Great Plains Energy		
Outlook	Stable	Stable
Corporate Credit Rating	-	BBB+
Preferred Stock	Ba1	BBB-
Senior Unsecured Debt	Baa2	BBB
KCP&L		
Outlook	Stable	Stable
Senior Secured Debt	A2	A
Senior Unsecured Debt	Baa1	BBB+
Commercial Paper	P-2	A-2
GMO		
Outlook	Stable	Stable
Senior Unsecured Debt	Baa2	BBB+
Commercial Paper	P-2	A-2

A securities rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency.

Financing Authorization

Under stipulations with the MPSC and KCC, Great Plains Energy and KCP&L maintain common equity at not less than 30% and 35%, respectively, of total capitalization (including only the amount of short-term debt in excess of the amount of construction work in progress). KCP&L's long-term financing activities are subject to the authorization of the MPSC. In July 2014, the MPSC authorized KCP&L to issue up to $350.0 million of long-term debt and enter into interest rate hedging instruments in connection with such debt through June 30, 2016. At December 31, 2015, KCP&L had utilized all of this authorization.

KCP&L's and GMO's short-term financing activities are subject to the authorization of FERC. In November 2014, FERC authorized KCP&L to have outstanding at any one time up to a total of $1.0 billion in short-term debt instruments through December 2016. At December 31, 2015 there was $819.7 million available under this authorization. In January 2014, FERC authorized GMO to have outstanding at any one time up to a total of $750.0 million in short-term debt instruments through March 2016. At December 31, 2015, there was $706.3 million available under this authorization.

KCP&L and GMO are also authorized by FERC to participate in the Great Plains Energy money pool, an internal financing arrangement in which funds may be lent on a short-term basis to KCP&L and GMO. At December 31, 2015, GMO had an outstanding payable to Great Plains Energy under the money pool of $3.7 million.

Significant Financing Activities

Great Plains Energy

Great Plains Energy has an effective shelf registration statement for the sale of unlimited amounts of securities with the SEC that was filed and became effective in March 2015 and expires in March 2018.

In August 2013, GMO entered into a note purchase agreement and issued the following series of unsecured senior notes:

- $125.0 million 3.49% Senior Notes, Series A, maturing in 2025;

- $75.0 million 4.06% Senior Notes, Series B, maturing in 2033; and
- $150.0 million 4.74% Senior Notes, Series C, maturing in 2043.

KCP&L

KCP&L has an effective shelf registration statement providing for the sale of unlimited amounts of notes and general mortgage bonds with the SEC that was filed and became effective in March 2015 and expires in March 2018.

In August 2015, KCP&L issued, at a discount, $350.0 million of 3.65% unsecured Senior Notes, maturing in 2025.

In March 2013, KCP&L issued, at a discount, $300.0 million of 3.15% unsecured Senior Notes, maturing in 2023.

In April 2013, KCP&L remarketed the following series of EIRR bonds that were previously held by KCP&L:

- secured Series 1993B EIRR bonds totaling $39.5 million at a fixed rate of 2.95% through maturity; and
- unsecured Series 2007A-1 and 2007A-2 EIRR bonds totaling $10.0 million and $63.3 million, respectively, maturing in 2035 into one series: Series 2007A totaling $73.3 million at a variable rate that will be determined weekly.

Debt Agreements

See Note 10 to the consolidated financial statements for information regarding revolving credit facilities.

Projected Utility Capital Expenditures

Great Plains Energy's cash utility capital expenditures, excluding AFUDC to finance construction, were $677.1 million, $773.7 million and $669.0 million in 2015, 2014 and 2013, respectively. Utility capital expenditures represent a significant portion of Great Plains Energy's capital requirements. Utility capital expenditures projected for the next five years include improvements to generating, distribution and transmission facilities, software upgrades and expenditures for environmental projects at coal-fired power plants. Great Plains Energy intends to meet these capital requirements with a combination of internally generated funds and proceeds from short-term and long-term debt.

Utility capital expenditures projected for the next five years, excluding AFUDC, are detailed in the following table. This utility capital expenditure plan is subject to continual review and change.

	2016	2017	2018	2019	2020
			(millions)		
Generating facilities	$ 231.7	$ 192.7	$ 204.3	$ 178.0	$ 192.7
Distribution and transmission facilities	229.1	197.4	192.3	216.7	203.5
General facilities	99.9	99.7	98.5	56.7	69.4
Nuclear fuel	19.8	45.4	25.2	22.9	50.0
Environmental	99.6	45.5	20.6	98.9	151.9
Total utility capital expenditures	$ 680.1	$ 580.7	$ 540.9	$ 573.2	$ 667.5

Pensions

The Company incurs significant costs in providing defined benefit plans for substantially all active and inactive employees of KCP&L and GMO and its 47% ownership share of WCNOC's defined benefit plans. Funding of the plans follows legal and regulatory requirements with funding equaling or exceeding the minimum requirements of employee retirement income security act of 1974, as amended (ERISA).

In 2015 and 2014, the Company contributed $76.9 million and $66.2 million to the pension plans, respectively, and expects to contribute $75.7 million in 2016 to satisfy the minimum ERISA funding requirements and the MPSC and KCC rate orders, the majority of which is expected to be paid by KCP&L. Additional contributions to the plans are

expected beyond 2016 in amounts at least sufficient to meet the greater of ERISA or regulatory funding requirements; however, these amounts have not yet been determined.

Additionally, the Company provides post-retirement health and life insurance benefits for certain retired employees and expects to make benefit contributions of $5.1 million under the provisions of these plans in 2016, the majority of which is expected to be paid by KCP&L.

Management believes the Company has adequate access to capital resources through cash flows from operations or through existing lines of credit to support these funding requirements.

Supplemental Capital Requirements and Liquidity Information
The information in the following table is provided to summarize Great Plains Energy's cash obligations and commercial commitments.

Payment due by period	2016	2017	2018	2019	2020	After 2020	Total
Long-term debt				(millions)			
Principal	$ 1.1	$ 382.1	$ 351.1	$ 401.1	$ 1.1	$ 2,629.1	$ 3,765.6
Interest	185.6	178.3	152.5	126.9	112.5	989.3	1,745.1
Lease commitments							
Operating leases	12.3	10.6	9.7	9.9	9.6	121.5	173.6
Capital leases	0.4	0.4	0.4	0.4	0.4	3.5	5.5
Pension and other post-retirement plans	80.8	80.8	80.8	80.8	80.8	(a)	404.0
Purchase commitments							
Fuel	311.4	283.2	212.7	196.9	190.3	52.5	1,247.0
Power	47.3	47.3	47.3	47.3	47.3	509.5	746.0
Capacity	1.2	—	—	—	—	—	1.2
Non-regulated natural gas transportation	3.5	0.9	—	—	—	—	4.4
Other	74.7	11.0	27.8	40.0	5.2	41.1	199.8
Total contractual commitments [a]	$ 718.3	$ 994.6	$ 882.3	$ 903.3	$ 447.2	$ 4,346.5	$ 8,292.2

[a] The Company expects to make contributions to the pension and other post-retirement plans beyond 2020 but the amounts are not yet determined. Amounts for years after 2016 are estimates based on information available in determining the amount for 2016. Actual amounts for years after 2016 could be significantly different than the estimated amounts in the table above.

Long-term debt includes current maturities. Long-term debt principal excludes $19.4 million of net discounts on senior notes and debt issuance costs. Variable rate interest obligations are based on rates as of December 31, 2015.

Lease commitments end in 2048. Operating lease commitments include railcars to serve jointly-owned generating units where KCP&L is the managing partner. Of the amounts included in the table above, KCP&L will be reimbursed by the other owners for approximately $1.5 million in 2016, $0.9 million in 2017 and approximately $0.4 million per year from 2018 to 2025, for a total of $6.0 million.

The Company expects to contribute $80.8 million to the pension and other post-retirement plans in 2016, of which the majority is expected to be paid by KCP&L. Additional contributions to the plans are expected beyond 2020 in amounts at least sufficient to meet the greater of ERISA or regulatory funding requirements; however, these amounts have not yet been determined. Amounts for years after 2016 are estimates based on information available in determining the amount for 2016. Actual amounts for years after 2016 could be significantly different than the estimated amounts in the table above.

Fuel commitments consist of commitments for nuclear fuel, coal and coal transportation costs. Power commitments consist of commitments for renewable energy under power purchase agreements. KCP&L and GMO purchase capacity from other utilities and nonutility suppliers. Purchasing capacity provides the option to purchase energy if needed or when market prices are favorable. KCP&L has capacity sales agreements not included above that total $6.0 million, $1.9 million, $2.1 million, $1.9 million and $2.0 million per year from 2016 to 2020. Non-regulated natural gas transportation consists of MPS Merchant's commitments. Other represents individual commitments entered into in the ordinary course of business.

Great Plains Energy has other insignificant long-term liabilities recorded on its consolidated balance sheet at December 31, 2015, which do not have a definitive cash payout date and are not included in the table above.

Off-Balance Sheet Arrangements

In the ordinary course of business, Great Plains Energy and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees and letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiary's intended business purposes. The majority of these agreements guarantee the Company's own future performance, so a liability for the fair value of the obligation is not recorded.

At December 31, 2015, Great Plains Energy has provided $138.4 million of credit support for GMO as follows:

- Great Plains Energy direct guarantees to GMO counterparties totaling $40.7 million, which expire in 2016 and
- Great Plains Energy guarantees of GMO long-term debt totaling $97.7 million, which includes debt with maturity dates ranging from 2016 to 2023.

Great Plains Energy has also guaranteed GMO's commercial paper program. At December 31, 2015, GMO had $43.7 million commercial paper outstanding. None of the guaranteed obligations are subject to default or prepayment if GMO's credit ratings were downgraded.

At December 31, 2015, KCP&L had issued letters of credit totaling $23.5 million as credit support to certain counterparties that expire in 2016. KCP&L has issued $148.1 million of letters of credit as credit support for its variable rate EIRR Bond Series 2007A and B that expire in 2018.

At December 31, 2015, GMO had issued letters of credit totaling $2.5 million as credit support to certain counterparties that expire in 2016.

KANSAS CITY POWER & LIGHT COMPANY

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The following table summarizes KCP&L's consolidated comparative results of operations.

	2015	2014
	(millions)	
Operating revenues	$ 1,713.8	$ 1,730.8
Fuel	(304.5)	(364.9)
Purchased power	(92.6)	(107.8)
Transmission	(58.4)	(47.2)
Gross margin [(a)]	1,258.3	1,210.9
Other operating expenses	(658.6)	(646.9)
Depreciation and amortization	(235.7)	(213.9)
Operating income	364.0	350.1
Non-operating income and expenses	1.2	12.1
Interest charges	(135.6)	(124.1)
Income tax expense	(76.8)	(75.7)
Net income	$ 152.8	$ 162.4

[(a)] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

KCP&L Gross Margin and MWh Sales

The following table summarizes KCP&L's gross margin and MWhs sold.

	Revenues and Costs		%	MWhs Sold		%
	2015	2014	Change[(c)]	2015	2014	Change
Retail revenues	(millions)			(thousands)		
Residential	$ 633.7	$ 620.6	2	5,213	5,394	(3)
Commercial	731.4	705.4	4	7,569	7,600	—
Industrial	135.9	131.8	3	1,833	1,841	—
Other retail revenues	12.6	12.3	1	83	85	(1)
Kansas property tax surcharge	0.7	2.1	(66)	N/A	N/A	N/A
Energy efficiency (MEEIA)[(a)]	27.5	9.2	N/M	N/A	N/A	N/A
Fuel recovery mechanism	14.6	10.6	39	N/A	N/A	N/A
Total retail	1,556.4	1,492.0	4	14,698	14,920	(1)
Wholesale revenues	134.1	220.3	(39)	6,099	7,552	(19)
Other revenues	23.3	18.5	27	N/A	N/A	N/A
Operating revenues	1,713.8	1,730.8	(1)	20,797	22,472	(7)
Fuel	(304.5)	(364.9)	(17)			
Purchased power	(92.6)	(107.8)	(14)			
Transmission	(58.4)	(47.2)	24			
Gross margin [(b)]	$ 1,258.3	$ 1,210.9	4			

[(a)] Consists of recovery of program costs of $20.5 million and $6.3 million for 2015 and 2014, respectively, that have a direct offset in operating and maintenance expenses and recovery of throughput disincentive of $7.0 million and $2.9 million for 2015 and 2014, respectively.

[(b)] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

[(c)] N/M - not meaningful

KCP&L's gross margin increased $47.4 million in 2015 compared to 2014 primarily due to:

- an estimated $36 million increase due to new retail rates for KCP&L in Missouri effective September 29, 2015, and in Kansas effective July 25, 2014 and October 1, 2015;
- a $14.2 million increase for recovery of program costs for energy efficiency programs under MEEIA, which have a direct offset in operating and maintenance expense, due to the implementation of KCP&L's MEEIA programs in August 2014;
- an estimated $16 million increase in other margin items including a change in customer mix, lower fuel and purchased power expenses that are not included in fuel recovery mechanisms and an increase in transmission costs recovered through the transmission delivery charge rider that began in the fourth quarter of 2015;
- an estimated $6 million increase from weather-normalized retail demand;
- an estimated $5 million decrease due to higher transmission expense;
- an estimated $19 million decrease due to lower wholesale margins partially offset by an estimated $14 million due to lower fuel and purchased power expense at KCP&L in Missouri, where there was no fuel recovery mechanism prior to September 29, 2015; and
- an estimated $15 million decrease due to weather driven by a 19% decrease in heating degree days in 2015 and a 15% decrease in cooling degree days in the second quarter of 2015 partially offset by an 18% increase in cooling degree days in the third quarter of 2015.

KCP&L Other Operating Expenses *(including operating and maintenance expenses, general taxes and other)*
KCP&L's other operating expenses increased $11.7 million in 2015 compared to 2014 primarily due to:

- a $14.2 million increase in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue, primarily due to the implementation of KCP&L's MEEIA programs in August 2014;
- a $4.4 million increase in general taxes driven by higher property taxes; and
- a $10.0 million decrease in Wolf Creek operating and maintenance expenses primarily due to decreased refueling outage amortization of $3.6 million and $8.7 million from a planned mid-cycle maintenance outage in 2014.

KCP&L Depreciation and Amortization
KCP&L's depreciation and amortization expense increased $21.8 million in 2015 compared to 2014 due to capital additions.

KCP&L Non-Operating Income and Expenses
KCP&L's non-operating income and expenses decreased $10.9 million in 2015 compared to 2014 due to a decrease in the equity component of AFUDC primarily due to a lower average construction work in progress in 2015 due to environmental upgrades at KCP&L's La Cygne Station being placed into service.

KCP&L Interest Charges
KCP&L's interest charges increased $11.5 million in 2015 compared to 2014 due to a decrease in the debt component of AFUDC primarily due to a lower average construction work in progress in 2015 due to environmental upgrades at KCP&L's La Cygne Station being placed into service.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the ordinary course of business, Great Plains Energy and KCP&L face risks that are either non-financial or non-quantifiable. Such risks principally include business, legal, operational and credit risks and are not represented in the following analysis. See Item 1A Risk Factors and Item 7 MD&A for further discussion of risk factors.

Great Plains Energy and KCP&L are exposed to market risks associated with commodity price and supply, interest rates and equity prices. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on its operating results. During the ordinary course of business, under the direction and control of an internal commodity risk committee, Great Plains Energy's and KCP&L's hedging strategies are reviewed to determine the hedging approach deemed appropriate based upon the circumstances of each situation. Though management believes its risk management practices are effective, it is not possible to identify and eliminate all risk. Great Plains Energy and KCP&L could experience losses, which could have a material adverse effect on their results of operations or financial position, due to many factors, including unexpectedly large or rapid movements or disruptions in the energy markets, from regulatory-driven market rule changes and/or bankruptcy or non-performance of customers or counterparties, and/or failure of underlying transactions that have been hedged to materialize.

Hedging Strategies
Derivative instruments are frequently utilized to execute risk management and hedging strategies. Derivative instruments, such as futures, forward contracts, swaps or options, derive their value from underlying assets, indices, reference rates or a combination of these factors. These derivative instruments include negotiated contracts, which are referred to as over-the-counter derivatives, and instruments listed and traded on an exchange.

Interest Rate Risk
Great Plains Energy and KCP&L manage interest expense and short- and long-term liquidity through a combination of fixed and variable rate debt. Generally, the amount of each type of debt is managed through market issuance, but interest rate swap and cap agreements with highly rated financial institutions may also be used to achieve the desired combination. At December 31, 2015, 4% and 6%, respectively, of Great Plains Energy's and KCP&L's long-term debt was variable rate debt. Interest rates impact the fair value of long-term debt. A change in interest rates would impact Great Plains Energy and KCP&L to the extent they redeemed any of their outstanding long-term debt. Great Plains Energy's and KCP&L's book values of long-term debt were below fair value by 7% at December 31, 2015.

Great Plains Energy had $10.0 million of notes payable outstanding at December 31, 2015. The principal amount of the notes payable, which will vary during the year, drives Great Plains Energy's notes payable interest expense. Assuming that $10.0 million of notes payable was outstanding for all of 2016, a hypothetical 10% increase in interest rates associated with short-term variable rate debt would result in an immaterial increase in interest expense for 2016.

Great Plains Energy and KCP&L had $224.0 million and $180.3 million, respectively, of commercial paper outstanding at December 31, 2015. The principal amount of the commercial paper, which will vary during the year, drives Great Plains Energy's and KCP&L's commercial paper interest expense. Assuming $224.0 million and $180.3 million of commercial paper was outstanding for all of 2016 for Great Plains Energy and KCP&L, respectively, a hypothetical 10% increase in commercial paper rates would result in an immaterial increase in interest expense for 2016. Assuming $224.0 million and $180.3 million of commercial paper was outstanding for all of 2016 for Great Plains Energy and KCP&L, respectively, a hypothetical 100 basis point increase in commercial paper rates would result in an increase in interest expense of $2.2 million for Great Plains Energy and $1.8 million for KCP&L in 2016.

Commodity Risk
Great Plains Energy and KCP&L engage in the wholesale and retail marketing of electricity and are exposed to risk associated with the price of electricity. Exposure to these risks is affected by a number of factors including the quantity and availability of fuel used for generation and the quantity of electricity customers consume. Customers' electricity usage could also vary from year to year based on the weather or other factors. Quantities of fossil fuel used for generation vary from year to year based on the availability, price and deliverability of a given fuel type as well as planned and unplanned outages at facilities that use fossil fuels.

KCP&L's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity. KCP&L is required to maintain a capacity margin of at least 12% of its peak summer demand.

This net positive supply of capacity and energy is maintained through KCP&L's generation assets and capacity and power purchase agreements to protect KCP&L from the potential operational failure of one of its power generating units. KCP&L continually evaluates the need for additional risk mitigation measures in order to minimize its financial exposure to, among other things, spikes in wholesale power prices during periods of high demand.

KCP&L's sales include the sale of electricity to its retail customers and bulk power sales of electricity in the wholesale market. KCP&L is a member of SPP Consolidated Balancing Authority (CBA) and Integrated Marketplace (IM), which are largely responsible for the dispatch of member generating facilities and the resulting supply of energy to fulfill member load obligations. KCP&L's Kansas ECA allows for the recovery of increased fuel and purchased power costs from Kansas retail customers. KCP&L's Missouri FAC allows for KCP&L Missouri retail electric rates to be adjusted based on 95% of the difference between actual fuel and purchased power costs and the amount of fuel and purchased power costs provided in base rates. Most of the change in market prices for fuel and purchased power is recovered through the ECA or FAC, which mitigates KCP&L's commodity price exposure.

GMO is also a member of SPP's CBA and IM. GMO has an FAC that allows GMO to adjust retail electric rates based on 95% of the difference between actual fuel and purchased power costs and the amount of fuel and purchased power costs provided in base rates. Most of the change in market prices for fuel and purchased power is recovered through the FAC, which mitigates GMO's commodity price exposure.

Credit Risk - MPS Merchant

MPS Merchant is exposed to credit risk. Credit risk is measured by the loss that would be recorded if counterparties failed to perform pursuant to the terms of the contractual obligations less the value of any collateral held. MPS Merchant's counterparties are not externally rated. Credit exposure to counterparties at December 31, 2015, was $7.2 million.

Investment Risk

KCP&L maintains trust funds, as required by the NRC, to fund its share of decommissioning the Wolf Creek nuclear power plant. As of December 31, 2015, these funds were invested primarily in domestic equity securities and fixed income securities and are reflected at fair value on KCP&L's balance sheets. The mix of securities is designed to provide returns to be used to fund decommissioning and to compensate for inflationary increases in decommissioning costs; however, the equity securities in the trusts are exposed to price fluctuations in equity markets and the value of fixed rate fixed income securities are exposed to changes in interest rates. A hypothetical increase in interest rates resulting in a hypothetical 10% decrease in the value of the fixed income securities would have resulted in a $6.2 million reduction in the value of the decommissioning trust funds at December 31, 2015. A hypothetical 10% decrease in equity prices would have resulted in a $13.5 million reduction in the fair value of the equity securities at December 31, 2015. KCP&L's exposure to investment risk associated with the decommissioning trust funds is in large part mitigated due to the fact that KCP&L is currently allowed to recover its decommissioning costs in its rates. If the actual return on trust assets is below the anticipated level, KCP&L could be responsible for the balance of funds required to decommission Wolf Creek; however, while there can be no assurances, management believes a rate increase would be allowed to recover decommissioning costs over the remaining life of the unit.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Great Plains Energy Incorporated
Kansas City, Missouri

We have audited the accompanying consolidated balance sheets of Great Plains Energy Incorporated and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Great Plains Energy Incorporated and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2016, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 24, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Kansas City Power & Light Company
Kansas City, Missouri

We have audited the accompanying consolidated balance sheets of Kansas City Power & Light Company and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of comprehensive income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Kansas City Power & Light Company and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2016, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 24, 2016

GREAT PLAINS ENERGY INCORPORATED
Consolidated Statements of Comprehensive Income

	2015	2014	2013
Operating Revenues	(millions, except per share amounts)		
Electric revenues	**$ 2,502.2**	$ 2,568.2	$ 2,446.3
Operating Expenses			
Fuel	**421.4**	489.2	539.5
Purchased power	**187.3**	253.3	125.9
Transmission	**89.1**	74.7	53.2
Utility operating and maintenance expenses	**724.8**	701.9	671.4
Depreciation and amortization	**330.4**	306.0	289.7
General taxes	**213.2**	204.6	194.4
Other	**5.9**	4.0	3.0
Total	**1,972.1**	2,033.7	1,877.1
Operating income	**530.1**	534.5	569.2
Non-operating income	**11.7**	25.0	18.4
Non-operating expenses	**(8.0)**	(12.5)	(9.6)
Interest charges	**(199.3)**	(188.5)	(198.4)
Income before income tax expense and income (loss) from equity investments	**334.5**	358.5	379.6
Income tax expense	**(122.7)**	(115.7)	(129.2)
Income (loss) from equity investments, net of income taxes	**1.2**	—	(0.2)
Net income	**213.0**	242.8	250.2
Preferred stock dividend requirements	**1.6**	1.6	1.6
Earnings available for common shareholders	**$ 211.4**	$ 241.2	$ 248.6
Average number of basic common shares outstanding	**154.2**	153.9	153.5
Average number of diluted common shares outstanding	**154.8**	154.1	153.7
Basic and diluted earnings per common share	**$ 1.37**	$ 1.57	$ 1.62
Comprehensive Income			
Net income	**$ 213.0**	$ 242.8	$ 250.2
Other comprehensive income			
Derivative hedging activity			
Reclassification to expenses, net of tax	**5.7**	8.0	11.6
Derivative hedging activity, net of tax	**5.7**	8.0	11.6
Defined benefit pension plans			
Net gain (loss) arising during period	**1.0**	(3.0)	2.1
Income tax (expense) benefit	**(0.4)**	1.2	(0.9)
Net gain (loss) arising during period, net of tax	**0.6**	(1.8)	1.2
Amortization of net losses included in net periodic benefit costs, net of tax	**0.4**	0.4	0.3
Change in unrecognized pension expense, net of tax	**1.0**	(1.4)	1.5
Total other comprehensive income	**6.7**	6.6	13.1
Comprehensive income	**$ 219.7**	$ 249.4	$ 263.3

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Balance Sheets

	December 31	
	2015	2014
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	$ 11.3	$ 13.0
Funds on deposit	2.1	1.2
Receivables, net	147.7	160.3
Accounts receivable pledged as collateral	175.0	171.0
Fuel inventories, at average cost	118.4	90.1
Materials and supplies, at average cost	155.7	152.7
Deferred refueling outage costs	19.2	12.5
Refundable income taxes	3.8	3.1
Deferred income taxes	—	78.1
Prepaid expenses and other assets	31.0	36.9
Total	664.2	718.9
Utility Plant, at Original Cost		
Electric	13,189.9	12,128.7
Less - accumulated depreciation	4,943.7	4,828.3
Net utility plant in service	8,246.2	7,300.4
Construction work in progress	347.9	900.0
Nuclear fuel, net of amortization of $192.5 and $187.5	68.3	79.2
Total	8,662.4	8,279.6
Investments and Other Assets		
Nuclear decommissioning trust fund	200.7	199.0
Regulatory assets	979.1	1,034.6
Goodwill	169.0	169.0
Other	63.2	52.3
Total	1,412.0	1,454.9
Total	$ 10,738.6	$ 10,453.4

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Balance Sheets

	December 31 2015	2014
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Notes payable	$ 10.0	$ 4.0
Collateralized note payable	175.0	171.0
Commercial paper	224.0	358.3
Current maturities of long-term debt	1.1	15.1
Accounts payable	352.9	388.0
Accrued taxes	31.6	30.4
Accrued interest	44.7	41.3
Accrued compensation and benefits	41.4	35.2
Pension and post-retirement liability	3.4	2.8
Other	31.6	24.7
Total	915.7	1,070.8
Deferred Credits and Other Liabilities		
Deferred income taxes	1,158.8	1,089.7
Deferred tax credits	125.1	126.0
Asset retirement obligations	275.9	195.9
Pension and post-retirement liability	455.2	508.6
Regulatory liabilities	284.4	282.7
Other	82.9	88.9
Total	2,382.3	2,291.8
Capitalization		
Great Plains Energy common shareholders' equity		
Common stock - 250,000,000 shares authorized without par value		
154,504,900 and 154,254,037 shares issued, stated value	2,646.7	2,639.3
Retained earnings	1,024.4	967.8
Treasury stock - 101,229 and 91,281 shares, at cost	(2.6)	(2.3)
Accumulated other comprehensive loss	(12.0)	(18.7)
Total	3,656.5	3,586.1
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	10.0	10.0
4.50% - 100,000 shares issued	10.0	10.0
4.20% - 70,000 shares issued	7.0	7.0
4.35% - 120,000 shares issued	12.0	12.0
Total	39.0	39.0
Long-term debt (Note 11)	3,745.1	3,465.7
Total	7,440.6	7,090.8
Commitments and Contingencies (Note 14)		
Total	$ 10,738.6	$ 10,453.4

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
Consolidated Statements of Cash Flows

Year Ended December 31	2015	2014	2013
Cash Flows from Operating Activities		(millions)	
Net income	$ 213.0	$ 242.8	$ 250.2
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	330.4	306.0	289.7
Amortization of:			
Nuclear fuel	26.8	26.1	22.8
Other	47.7	46.1	57.5
Deferred income taxes, net	124.9	125.8	134.0
Investment tax credit amortization	(1.4)	(1.4)	(1.7)
(Income) loss from equity investments, net of income taxes	(1.2)	—	0.2
Other operating activities (Note 2)	12.9	(47.2)	24.1
Net cash from operating activities	753.1	698.2	776.8
Cash Flows from Investing Activities			
Utility capital expenditures	(677.1)	(773.7)	(669.0)
Allowance for borrowed funds used during construction	(5.8)	(13.0)	(11.8)
Purchases of nuclear decommissioning trust investments	(50.9)	(27.5)	(73.5)
Proceeds from nuclear decommissioning trust investments	47.6	24.2	70.2
Proceeds from sale of transmission assets	—	37.7	—
Other investing activities	(48.2)	(27.5)	(21.7)
Net cash from investing activities	(734.4)	(779.8)	(705.8)
Cash Flows from Financing Activities			
Issuance of common stock	3.0	4.8	4.9
Issuance of long-term debt	348.8	—	762.5
Issuance of long-term debt from remarketing	146.5	—	—
Repayment of long-term debt from remarketing	(146.5)	—	—
Issuance fees	(3.0)	(0.9)	(9.0)
Repayment of long-term debt	(87.0)	(13.4)	(265.3)
Net change in short-term borrowings	(128.3)	245.1	(424.9)
Net change in collateralized short-term borrowings	4.0	(4.0)	1.0
Dividends paid	(155.5)	(145.6)	(137.3)
Other financing activities	(2.4)	(2.0)	(1.6)
Net cash from financing activities	(20.4)	84.0	(69.7)
Net Change in Cash and Cash Equivalents	(1.7)	2.4	1.3
Cash and Cash Equivalents at Beginning of Year	13.0	10.6	9.3
Cash and Cash Equivalents at End of Year	$ 11.3	$ 13.0	$ 10.6

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Statements of Common Shareholders' Equity

Year Ended December 31	2015		2014		2013	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Common Stock			(millions, except share amounts)			
Beginning balance	**154,254,037**	**$ 2,639.3**	153,995,621	$ 2,631.1	153,779,806	$ 2,624.7
Issuance of common stock	**250,863**	**6.6**	258,416	6.7	215,815	4.9
Equity compensation expense, net of forfeitures		**1.9**		0.5		0.4
Unearned Compensation						
Issuance of restricted common stock		**(2.4)**		(2.1)		(1.8)
Forfeiture of restricted common stock		**0.5**		—		0.1
Compensation expense recognized		**1.8**		2.0		2.1
Other		**(1.0)**		1.1		0.7
Ending balance	**154,504,900**	**2,646.7**	154,254,037	2,639.3	153,995,621	2,631.1
Retained Earnings						
Beginning balance		**967.8**		871.4		758.8
Net income		**213.0**		242.8		250.2
Dividends:						
Common stock ($0.9975, $0.935 and $0.8825 per share)		**(153.9)**		(144.0)		(135.7)
Preferred stock - at required rates		**(1.6)**		(1.6)		(1.6)
Performance shares		**(0.9)**		(0.8)		(0.3)
Ending balance		**1,024.4**		967.8		871.4
Treasury Stock						
Beginning balance	**(91,281)**	**(2.3)**	(129,290)	(2.8)	(250,236)	(5.1)
Treasury shares acquired	**(76,468)**	**(2.0)**	(85,744)	(2.2)	(73,201)	(1.6)
Treasury shares reissued	**66,520**	**1.7**	123,753	2.7	194,147	3.9
Ending balance	**(101,229)**	**(2.6)**	(91,281)	(2.3)	(129,290)	(2.8)
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(18.7)**		(25.3)		(38.4)
Derivative hedging activity, net of tax		**5.7**		8.0		11.6
Change in unrecognized pension expense, net of tax		**1.0**		(1.4)		1.5
Ending balance		**(12.0)**		(18.7)		(25.3)
Total Great Plains Energy Common Shareholders' Equity		**$ 3,656.5**		$ 3,586.1		$ 3,474.4

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Statements of Comprehensive Income

Year Ended December 31	2015	2014	2013
Operating Revenues	(millions)		
Electric revenues	$ 1,713.8	$ 1,730.8	$ 1,671.4
Operating Expenses			
Fuel	304.5	364.9	383.0
Purchased power	92.6	107.8	62.4
Transmission	58.4	47.2	37.3
Operating and maintenance expenses	494.2	489.1	475.9
Depreciation and amortization	235.7	213.9	198.3
General taxes	163.5	159.1	152.0
Other	0.9	(1.3)	—
Total	1,349.8	1,380.7	1,308.9
Operating income	364.0	350.1	362.5
Non-operating income	8.4	20.4	16.3
Non-operating expenses	(7.2)	(8.3)	(4.7)
Interest charges	(135.6)	(124.1)	(125.3)
Income before income tax expense	229.6	238.1	248.8
Income tax expense	(76.8)	(75.7)	(79.8)
Net income	$ 152.8	$ 162.4	$ 169.0
Comprehensive Income			
Net income	$ 152.8	$ 162.4	$ 169.0
Other comprehensive income			
Derivative hedging activity			
Reclassification to expenses, net of tax	5.3	5.3	5.6
Derivative hedging activity, net of tax	5.3	5.3	5.6
Total other comprehensive income	5.3	5.3	5.6
Comprehensive income	$ 158.1	$ 167.7	$ 174.6

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Balance Sheets

	December 31	
	2015	2014
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 2.3**	$ 2.7
Funds on deposit	**0.5**	0.6
Receivables, net	**129.2**	128.9
Related party receivables	**65.8**	68.8
Accounts receivable pledged as collateral	**110.0**	110.0
Fuel inventories, at average cost	**83.5**	58.8
Materials and supplies, at average cost	**114.6**	110.1
Deferred refueling outage costs	**19.2**	12.5
Refundable income taxes	**79.0**	57.5
Deferred income taxes	**—**	5.0
Prepaid expenses and other assets	**27.1**	32.7
Total	**631.2**	587.6
Utility Plant, at Original Cost		
Electric	**9,640.4**	8,737.3
Less - accumulated depreciation	**3,722.6**	3,658.7
Net utility plant in service	**5,917.8**	5,078.6
Construction work in progress	**246.6**	791.2
Nuclear fuel, net of amortization of $192.5 and $187.5	**68.3**	79.2
Total	**6,232.7**	5,949.0
Investments and Other Assets		
Nuclear decommissioning trust fund	**200.7**	199.0
Regulatory assets	**732.4**	745.7
Other	**17.6**	13.8
Total	**950.7**	958.5
Total	**$ 7,814.6**	$ 7,495.1

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Balance Sheets

	December 31	
	2015	2014
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Collateralized note payable	**$ 110.0**	$ 110.0
Commercial paper	**180.3**	358.3
Current maturities of long-term debt	**—**	14.0
Accounts payable	**258.8**	305.2
Related party payables	**—**	12.6
Accrued taxes	**25.6**	23.6
Accrued interest	**32.4**	29.0
Accrued compensation and benefits	**41.4**	35.2
Pension and post-retirement liability	**2.0**	1.5
Other	**12.6**	12.4
Total	**663.1**	901.8
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,132.6**	1,016.9
Deferred tax credits	**123.8**	124.3
Asset retirement obligations	**239.3**	177.7
Pension and post-retirement liability	**433.4**	485.4
Regulatory liabilities	**164.6**	172.0
Other	**61.6**	59.2
Total	**2,155.3**	2,035.5
Capitalization		
Common shareholder's equity		
Common stock - 1,000 shares authorized without par value		
1 share issued, stated value	**1,563.1**	1,563.1
Retained earnings	**879.6**	726.8
Accumulated other comprehensive loss	**(9.6)**	(14.9)
Total	**2,433.1**	2,275.0
Long-term debt (Note 11)	**2,563.1**	2,282.8
Total	**4,996.2**	4,557.8
Commitments and Contingencies (Note 14)		
Total	**$ 7,814.6**	$ 7,495.1

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Statements of Cash Flows

Year Ended December 31	2015	2014	2013
Cash Flows from Operating Activities		(millions)	
Net income	**$ 152.8**	$ 162.4	$ 169.0
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**235.7**	213.9	198.3
Amortization of:			
Nuclear fuel	**26.8**	26.1	22.8
Other	**29.1**	29.3	34.3
Deferred income taxes, net	**99.4**	88.4	92.1
Investment tax credit amortization	**(1.0)**	(1.0)	(1.1)
Other operating activities (Note 2)	**(61.5)**	(64.7)	(9.2)
Net cash from operating activities	**481.3**	454.4	506.2
Cash Flows from Investing Activities			
Utility capital expenditures	**(518.3)**	(635.9)	(521.9)
Allowance for borrowed funds used during construction	**(3.9)**	(11.1)	(10.6)
Purchases of nuclear decommissioning trust investments	**(50.9)**	(27.5)	(73.5)
Proceeds from nuclear decommissioning trust investments	**47.6**	24.2	70.2
Proceeds from sale of transmission assets	**—**	4.7	—
Other investing activities	**(25.5)**	(15.2)	(12.4)
Net cash from investing activities	**(551.0)**	(660.8)	(548.2)
Cash Flows from Financing Activities			
Issuance of long-term debt	**348.8**	—	412.5
Issuance of long-term debt from remarketing	**146.5**	—	—
Repayment of long-term debt from remarketing	**(146.5)**	—	—
Issuance fees	**(3.0)**	(0.4)	(5.7)
Repayment of long-term debt	**(85.9)**	—	(2.6)
Net change in short-term borrowings	**(178.0)**	265.1	(267.8)
Net money pool borrowings	**(12.6)**	12.4	(3.6)
Dividends paid to Great Plains Energy	**—**	(72.0)	(92.0)
Net cash from financing activities	**69.3**	205.1	40.8
Net Change in Cash and Cash Equivalents	**(0.4)**	(1.3)	(1.2)
Cash and Cash Equivalents at Beginning of Year	**2.7**	4.0	5.2
Cash and Cash Equivalents at End of Year	**$ 2.3**	$ 2.7	$ 4.0

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Statements of Common Shareholder's Equity

Year Ended December 31	2015		2014		2013	
	Shares	Amount	Shares	Amount	Shares	Amount
	(millions, except share amounts)					
Common Stock	**1**	**$ 1,563.1**	1	$ 1,563.1	1	$ 1,563.1
Retained Earnings						
Beginning balance		**726.8**		636.4		559.4
Net income		**152.8**		162.4		169.0
Dividends:						
Common stock held by Great Plains Energy		**—**		(72.0)		(92.0)
Ending balance		**879.6**		726.8		636.4
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(14.9)**		(20.2)		(25.8)
Derivative hedging activity, net of tax		**5.3**		5.3		5.6
Ending balance		**(9.6)**		(14.9)		(20.2)
Total Common Shareholder's Equity		**$ 2,433.1**		$ 2,275.0		$ 2,179.3

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Notes to Consolidated Financial Statements

The notes to consolidated financial statements that follow are a combined presentation for Great Plains Energy Incorporated and Kansas City Power & Light Company, both registrants under this filing. The terms "Great Plains Energy," "Company," "KCP&L" and "Companies" are used throughout this report. "Great Plains Energy" and the "Company" refer to Great Plains Energy Incorporated and its consolidated subsidiaries, unless otherwise indicated. "KCP&L" refers to Kansas City Power & Light Company and its consolidated subsidiaries. "Companies" refers to Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

Great Plains Energy, a Missouri corporation incorporated in 2001, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries. Great Plains Energy's wholly owned direct subsidiaries with significant operations are as follows:

- KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (KCP&L Receivables Company).
- KCP&L Greater Missouri Operations Company (GMO) is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO has two active wholly owned subsidiaries, GMO Receivables Company and MPS Merchant Services, Inc. (MPS Merchant). MPS Merchant has certain long-term natural gas contracts remaining from its former non-regulated trading operations.

Great Plains Energy also wholly owns GPE Transmission Holding Company, LLC (GPETHC). GPETHC owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC (AEPTHC), a subsidiary of American Electric Power Company, Inc. GPETHC accounts for its investment in Transource under the equity method. Transource is focused on the development of competitive electric transmission projects.

Each of Great Plains Energy's and KCP&L's consolidated financial statements includes the accounts of their subsidiaries. Intercompany transactions have been eliminated.

Great Plains Energy's sole reportable business segment is electric utility. See Note 22 for additional information.

Use of Estimates

The process of preparing financial statements in conformity with Generally Accepted Accounting Principles (GAAP) requires the use of estimates and assumptions that affect the reported amounts of certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less at acquisition.

Funds on Deposit

Funds on deposit consist primarily of cash provided to counterparties in support of margin requirements related to commodity purchases, commodity swaps and futures contracts. Pursuant to individual contract terms with counterparties, deposit amounts required vary with changes in market prices, credit provisions and various other factors. Interest is earned on most funds on deposit. Great Plains Energy also holds funds on deposit from

counterparties in the same manner. These funds are included in other current liabilities on the consolidated balance sheets.

Fair Value of Financial Instruments
The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practicable to estimate that value.

Nuclear decommissioning trust fund - KCP&L's nuclear decommissioning trust fund assets are recorded at fair value based on quoted market prices of the investments held by the fund and/or valuation models.

Derivative instruments - The fair value of derivative instruments is estimated using market quotes, over-the-counter forward price and volatility curves and correlation among fuel prices, net of estimated credit risk.

Pension plans - For financial reporting purposes, the market value of plan assets is the fair value. For regulatory reporting purposes, a five-year smoothing of assets is used to determine fair value.

Derivative Instruments
The Company records derivative instruments on the balance sheet at fair value in accordance with GAAP. Great Plains Energy and KCP&L enter into derivative contracts to manage exposure to commodity price and interest rate fluctuations. Derivative instruments are used solely for hedging purposes and are not issued or held for speculative reasons.

The Company considers various qualitative factors, such as contract and market place attributes, in designating derivative instruments at inception. Great Plains Energy and KCP&L may elect the normal purchases and normal sales (NPNS) exception, which requires the effects of the derivative to be recorded when the underlying contract settles. Great Plains Energy and KCP&L account for derivative instruments that are not designated as NPNS as non-hedging derivatives, which are recorded as assets or liabilities on the consolidated balance sheets at fair value. See Note 18 for additional information regarding derivative financial instruments and hedging activities.

Great Plains Energy and KCP&L offset fair value amounts recognized for derivative instruments under master netting arrangements, which include rights to reclaim cash collateral (a receivable), or the obligation to return cash collateral (a payable).

Utility Plant
Great Plains Energy's and KCP&L's utility plant is stated at historical cost. These costs include taxes, an allowance for the cost of borrowed and equity funds used to finance construction and payroll-related costs, including pensions and other fringe benefits. Replacements, improvements and additions to units of property are capitalized. Repairs of property and replacements of items not considered to be units of property are expensed as incurred (except as discussed under Deferred Refueling Outage Costs). When property units are retired or otherwise disposed, the original cost, net of salvage, is charged to accumulated depreciation. Substantially all of KCP&L's utility plant is pledged as collateral for KCP&L's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated December 1, 1986, as supplemented. Substantially all of GMO's St. Joseph Light & Power division utility plant is pledged as collateral for GMO's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated April 1, 1946, as supplemented.

As prescribed by The Federal Energy Regulatory Commission (FERC), Allowance for Funds Used During Construction (AFUDC) is charged to the cost of the plant during construction. AFUDC equity funds are included as a non-cash item in non-operating income and AFUDC borrowed funds are a reduction of interest charges. The rates used to compute gross AFUDC are compounded semi-annually. The rates used to compute gross AFUDC for KCP&L averaged 3.0% in 2015, 5.7% in 2014 and 6.1% in 2013. The rates used to compute gross AFUDC for GMO averaged 4.2% in 2015, 6.1% in 2014 and 2.1% in 2013.

Great Plains Energy's and KCP&L's balances of utility plant, at original cost, with a range of estimated useful lives are listed in the following tables.

Great Plains Energy

December 31	2015	2014
Utility plant, at original cost	(millions)	
Generation (20 - 60 years)	$ 7,923.8	$ 7,169.6
Transmission (15 - 70 years)	848.8	821.9
Distribution (8 - 66 years)	3,498.6	3,311.6
General (5 - 50 years)	918.7	825.6
Total [(a)]	$ 13,189.9	$ 12,128.7

[(a)] Includes $214.0 million and $127.9 million at December 31, 2015 and 2014, respectively, of land and other assets that are not depreciated.

KCP&L

December 31	2015	2014
Utility plant, at original cost	(millions)	
Generation (20 - 60 years)	$ 6,222.5	$ 5,554.3
Transmission (15 - 70 years)	465.3	448.9
Distribution (8 - 55 years)	2,215.2	2,089.0
General (5 - 50 years)	737.4	645.1
Total [(a)]	$ 9,640.4	$ 8,737.3

[(a)] Includes $136.5 million and $72.4 million at December 31, 2015 and 2014, respectively, of land and other assets that are not depreciated.

Depreciation and Amortization

Depreciation and amortization of utility plant other than nuclear fuel is computed using the straight-line method over the estimated lives of depreciable property based on rates approved by state regulatory authorities. Annual depreciation rates average approximately 3%. Nuclear fuel is amortized to fuel expense based on the quantity of heat produced during the generation of electricity.

Great Plains Energy's depreciation expense was $299.4 million, $277.9 million and $265.4 million for 2015, 2014 and 2013, respectively. KCP&L's depreciation expense was $208.5 million, $189.7 million and $179.2 million for 2015, 2014 and 2013, respectively.

Nuclear Plant Decommissioning Costs

Nuclear plant decommissioning cost estimates are based on the immediate dismantlement method and include the costs of decontamination, dismantlement and site restoration. Based on these cost estimates, KCP&L contributes to a tax-qualified trust fund to be used to decommission Wolf Creek Generating Station (Wolf Creek). Related liabilities for decommissioning are included on Great Plains Energy's and KCP&L's balance sheets in Asset Retirement Obligations (AROs).

As a result of the authorized regulatory treatment and related regulatory accounting, differences between the decommissioning trust fund asset and the related ARO are recorded as a regulatory asset or liability. See Note 7 for discussion of AROs including those associated with nuclear plant decommissioning costs.

Deferred Refueling Outage Costs

KCP&L uses the deferral method to account for operations and maintenance expenses incurred in support of Wolf Creek's scheduled refueling outages and amortizes them evenly (monthly) over the unit's operating cycle, which is approximately 18 months, until the next scheduled outage. Replacement power costs during an outage are expensed as incurred.

Regulatory Matters
KCP&L and GMO defer items on the balance sheet resulting from the effects of the ratemaking process, which would not be recorded if KCP&L and GMO were not regulated. See Note 5 for additional information concerning regulatory matters.

Revenue Recognition
Great Plains Energy and KCP&L recognize revenues on sales of electricity when the service is provided. Revenues recorded include electric services provided but not yet billed by KCP&L and GMO. Unbilled revenues are recorded for kWh usage in the period following the customers' billing cycle to the end of the month. KCP&L's and GMO's estimate is based on net system kWh usage less actual billed kWhs. KCP&L's and GMO's estimated unbilled kWhs are allocated and priced by regulatory jurisdiction across the rate classes based on actual billing rates.

KCP&L and GMO collect from customers gross receipts taxes levied by state and local governments. These taxes from KCP&L's Missouri customers are recorded gross in operating revenues and general taxes on Great Plains Energy's and KCP&L's statements of comprehensive income. KCP&L's gross receipts taxes collected from Missouri customers were $62.0 million, $60.4 million and $58.9 million in 2015, 2014 and 2013, respectively. These taxes from KCP&L's Kansas customers and GMO's customers are recorded net in operating revenues on Great Plains Energy's and KCP&L's statements of comprehensive income.

Great Plains Energy and KCP&L collect sales taxes from customers and remit to state and local governments. These taxes are presented on a net basis on Great Plains Energy's and KCP&L's statements of comprehensive income.

Great Plains Energy and KCP&L record sale and purchase activity on a net basis in wholesale revenue or purchased power when transacting with Regional Transmission Organization (RTO)/Independent System Operator (ISO) markets.

Allowance for Doubtful Accounts
This reserve represents estimated uncollectible accounts receivable and is based on management's judgment considering historical loss experience and the characteristics of existing accounts. Provisions for losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are charged off against the reserve when they are deemed uncollectible.

Property Gains and Losses
Net gains and losses from the sale of assets and businesses and from asset impairments are recorded in operating expenses.

Asset Impairments
Long-lived assets and finite-lived intangible assets subject to amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset to be held and used is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. The amount of impairment recognized is the excess of the carrying value of the asset over its fair value.

Goodwill and indefinite lived intangible assets are tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The annual test must be performed at the same time each year. If the fair value of a reporting unit is less than its carrying value including goodwill, an impairment charge for goodwill must be recognized in the financial statements. To measure the amount of the impairment loss to recognize, the implied fair value of the reporting unit goodwill is compared with its carrying value.

Income Taxes
Income taxes are accounted for using the asset/liability approach. Deferred tax assets and liabilities are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, applying enacted statutory tax rates in effect for the year in which the differences are expected to reverse. Deferred tax assets

are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion of the deferred tax assets will not be realized.

Great Plains Energy and KCP&L recognize tax benefits based on a "more-likely-than-not" recognition threshold. In addition, Great Plains Energy and KCP&L recognize interest accrued related to unrecognized tax benefits in interest expense and penalties in non-operating expenses.

Great Plains Energy files a consolidated federal income tax return as well as unitary and combined income tax returns in several state jurisdictions with Kansas and Missouri being the most significant. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of income or loss. KCP&L's income tax provision includes taxes allocated based on its separate company income or loss.

Great Plains Energy and KCP&L have established a net regulatory asset for the additional future revenues to be collected from customers for deferred income taxes. Tax credits are recognized in the year generated except for certain KCP&L and GMO investment tax credits that have been deferred and amortized over the remaining service lives of the related properties.

Environmental Matters
Environmental costs are accrued when it is probable a liability has been incurred and the amount of the liability can be reasonably estimated.

Basic and Diluted Earnings per Common Share Calculation
To determine basic earnings per common share (EPS), preferred stock dividend requirements are deducted from net income before dividing by the average number of common shares outstanding. The effect of dilutive securities, calculated using the treasury stock method, assumes the issuance of common shares applicable to performance shares and restricted stock.

The following table reconciles Great Plains Energy's basic and diluted EPS.

	2015	2014	2013
	(millions, except per share amounts)		
Income			
Net income	$ 213.0	$ 242.8	$ 250.2
Less: preferred stock dividend requirements	1.6	1.6	1.6
Earnings available for common shareholders	$ 211.4	$ 241.2	$ 248.6
Common Shares Outstanding			
Average number of common shares outstanding	154.2	153.9	153.5
Add: effect of dilutive securities	0.6	0.2	0.2
Diluted average number of common shares outstanding	154.8	154.1	153.7
Basic and Diluted EPS	$ 1.37	$ 1.57	$ 1.62

Anti-dilutive shares excluded from the computation of diluted EPS are detailed in the following table.

	2015	2014	2013
Performance shares	—	482,987	548,242
Restricted stock shares	900	3,287	2,228

Dividends Declared
In February 2016, Great Plains Energy's Board of Directors (Board) declared a quarterly dividend of $0.2625 per share on Great Plains Energy's common stock. The common dividend is payable March 21, 2016, to shareholders of record as of February 29, 2016. The Board also declared regular dividends on Great Plains Energy's preferred stock, payable June 1, 2016, to shareholders of record as of May 10, 2016.

New Accounting Standards

ASU No. 2015-03 - Simplifying the Presentation of Debt Issuance Costs

In April 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs*, which requires that debt issuance costs related to a recognized debt liability be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The new guidance is to be applied retrospectively and is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted. The Companies elected to early adopt at December 31, 2015, and accordingly have retrospectively adjusted prior periods. The following table reflects the change on the line items of Great Plains Energy's and KCP&L's consolidated balance sheets at December 31, 2014.

	December 31, 2014		
	As Previously Reported	Effect of Change	As Reported
Great Plains Energy		(millions)	
Other Investments and Other Assets	$ 74.6	$ (22.3)	$ 52.3
Long-term debt	3,488.0	(22.3)	3,465.7
KCP&L			
Other Investments and Other Assets	$ 29.5	$ (15.7)	$ 13.8
Long-term debt	2,298.5	(15.7)	2,282.8

ASU No. 2015-07 - Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)

In May 2015, the FASB issued ASU No. 2015-07, *Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*. This guidance removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. The new guidance is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted. The Companies elected to early adopt at December 31, 2015, and accordingly have retrospectively adjusted prior periods.

ASU No. 2015-17 - Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes*, which simplifies the presentation of deferred taxes by requiring deferred tax assets and liabilities be classified as noncurrent on the balance sheet. The new guidance is effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. The Companies elected to early adopt this guidance, prospectively, at December 31, 2015. Prior periods were not retrospectively adjusted.

ASU No. 2014-09 - Revenue from Contracts with Customers

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers*, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. The ASU will replace most existing revenue recognition guidance in GAAP when it becomes effective. In August 2015, the FASB issued ASU No. 2015-14, deferring the effective date of ASU No. 2014-09 one year, from January 1, 2017, to January 1, 2018. The Companies plan to adopt ASU No. 2014-09 on January 1, 2018. The standard permits the use of either the retrospective or cumulative effect transition method. The Companies are evaluating the effect that ASU No. 2014-09 will have on their consolidated financial statements and related disclosures and have not yet selected a transition method nor have they determined the effect of the standard on their ongoing financial reporting.

2. SUPPLEMENTAL CASH FLOW INFORMATION

Great Plains Energy Other Operating Activities

Year Ended December 31	2015	2014	2013
Cash flows affected by changes in:		(millions)	
Receivables	$ 12.5	$ 3.0	$ (7.1)
Accounts receivable pledged as collateral	(4.0)	4.0	(1.0)
Fuel inventories	(28.3)	(13.7)	18.7
Materials and supplies	(3.0)	(0.4)	(1.0)
Accounts payable	(11.4)	15.2	26.4
Accrued taxes	1.1	8.3	2.2
Accrued interest	3.4	(4.1)	3.9
Deferred refueling outage costs	(6.7)	17.0	(17.6)
Pension and post-retirement benefit obligations	18.5	25.5	31.3
Allowance for equity funds used during construction	(4.8)	(18.0)	(14.1)
Fuel recovery mechanism	47.5	(28.5)	(1.3)
Solar rebates paid	(9.0)	(43.2)	(32.5)
Other	(2.9)	(12.3)	16.2
Total other operating activities	$ 12.9	$ (47.2)	$ 24.1
Cash paid during the period:			
Interest	$ 182.2	$ 174.8	$ 170.8
Income taxes	$ 0.1	$ —	$ —
Non-cash investing activities:			
Liabilities accrued for capital expenditures	$ 35.7	$ 57.4	$ 48.1

KCP&L Other Operating Activities

Year Ended December 31	2015	2014	2013
Cash flows affected by changes in:		(millions)	
Receivables	$ 2.6	$ (18.1)	$ (12.6)
Fuel inventories	(24.7)	(8.5)	13.3
Materials and supplies	(4.5)	(1.1)	1.1
Accounts payable	(18.0)	20.4	7.3
Accrued taxes	(19.0)	(42.5)	(3.7)
Accrued interest	3.4	(0.1)	1.4
Deferred refueling outage costs	(6.7)	17.0	(17.6)
Pension and post-retirement benefit obligations	18.4	26.9	35.7
Allowance for equity funds used during construction	(3.8)	(16.0)	(14.1)
Fuel recovery mechanism	3.5	(2.2)	(1.8)
Solar rebates paid	(7.2)	(17.3)	(8.2)
Other	(5.5)	(23.2)	(10.0)
Total other operating activities	$ (61.5)	$ (64.7)	$ (9.2)
Cash paid during the period:			
Interest	$ 120.2	$ 112.1	$ 111.7
Income taxes	$ —	$ 30.2	$ 4.6
Non-cash investing activities:			
Liabilities accrued for capital expenditures	$ 23.9	$ 48.8	$ 40.5

3. RECEIVABLES

Great Plains Energy's and KCP&L's receivables are detailed in the following table.

	December 31	
	2015	2014
Great Plains Energy	(millions)	
Customer accounts receivable - billed	$ 3.4	$ 1.1
Customer accounts receivable - unbilled	71.6	75.3
Allowance for doubtful accounts - customer accounts receivable	(3.8)	(2.8)
Other receivables	76.5	86.7
Total	$ 147.7	$ 160.3
KCP&L		
Customer accounts receivable - billed	$ 2.8	$ 0.6
Customer accounts receivable - unbilled	58.8	49.7
Allowance for doubtful accounts - customer accounts receivable	(1.8)	(1.2)
Other receivables	69.4	79.8
Total	$ 129.2	$ 128.9

Great Plains Energy's and KCP&L's other receivables at December 31, 2015, and 2014, consisted primarily of receivables from partners in jointly owned electric utility plants and wholesale sales receivables.

Sale of Accounts Receivable – KCP&L and GMO

KCP&L and GMO sell all of their retail electric accounts receivable to their wholly owned subsidiaries, KCP&L Receivables Company and GMO Receivables Company, respectively, which in turn sell an undivided percentage ownership interest in the accounts receivable to Victory Receivables Corporation, an independent outside investor. Each of KCP&L Receivables Company's and GMO Receivables Company's sale of the undivided percentage ownership interest in accounts receivable to Victory Receivables Corporation is accounted for as a secured borrowing with accounts receivable pledged as collateral and a corresponding short-term collateralized note payable recognized on the balance sheets. At December 31, 2015, and 2014, Great Plains Energy's accounts receivable pledged as collateral and the corresponding short-term collateralized note payable were $175.0 million and $171.0 million, respectively. At December 31, 2015, and 2014, KCP&L's accounts receivable pledged as collateral and the corresponding short-term collateralized note payable were $110.0 million. KCP&L's agreement expires in September 2016 and allows for $110 million in aggregate outstanding principal amount at any time. GMO's agreement expires in September 2016 and allows for $65 million in aggregate outstanding principal from mid-November through mid-June and then increases to $80 million from mid-June through mid-November.

4. NUCLEAR PLANT

KCP&L owns 47% of Wolf Creek, its only nuclear generating unit. Wolf Creek is located in Coffey County, Kansas, just northeast of Burlington, Kansas. Wolf Creek's operating license expires in 2045. Wolf Creek is regulated by the Nuclear Regulatory Commission (NRC), with respect to licensing, operations and safety-related requirements.

Spent Nuclear Fuel and High-Level Radioactive Waste

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek paid the DOE a quarterly fee of one-tenth of a cent for each kWh of net nuclear generation delivered and sold for the future disposal of spent nuclear fuel. In May 2014, this fee was set to zero.

In 2010, the DOE filed a motion with the NRC to withdraw its then pending application to the NRC to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada. An NRC board denied the DOE's motion to withdraw its application. In 2011, the NRC reexamined its decision and ordered the licensing board, consistent with budgetary limitations, to close out its work on the DOE's

application. In August 2013, a federal court of appeals ruled that the NRC must resume its review of the DOE's application.

Wolf Creek is currently evaluating alternatives for expanding its existing on-site spent nuclear fuel storage to provide additional capacity prior to 2025. Management cannot predict when, or if, an off-site storage site or alternative disposal site will be available to receive Wolf Creek's spent nuclear fuel and will continue to monitor this activity.

Low-Level Radioactive Waste

Wolf Creek disposes of most of its low-level radioactive waste (Class A waste) at an existing third-party repository in Utah. Management expects that the site located in Utah will remain available to Wolf Creek for disposal of its Class A waste. Wolf Creek has contracted with a waste processor that will process, take title and dispose in another state most of the remainder of Wolf Creek's low-level radioactive waste (Classes B and C waste, which is higher in radioactivity but much lower in volume). Should on-site waste storage be needed in the future, Wolf Creek has current storage capacity on site for about four years' generation of Classes B and C waste and believes it will be able to expand that storage capacity as needed if it becomes necessary to do so.

Nuclear Plant Decommissioning Costs

The Public Service Commission of the State of Missouri (MPSC) and The State Corporation Commission of the State of Kansas (KCC) require KCP&L and the other owners of Wolf Creek to submit an updated decommissioning cost study every three years and to propose funding levels. The most recent study was submitted to the MPSC and KCC in August 2014 and is the basis for the current cost of decommissioning estimates in the following table. Funding levels included in KCP&L retail rates have not changed.

	KCC	MPSC
	(millions)	
Current cost of decommissioning (in 2014 dollars)		
Total Station	$ 765.1	$ 765.1
KCP&L's 47% Share	359.6	359.6
Future cost of decommissioning (in 2045-2053 dollars) [(a)]		
Total Station	$ 2,201.5	$ 2,253.1
KCP&L's 47% Share	1,034.7	1,059.0
Annual escalation factor	3.15%	3.22%
Annual return on trust assets [(b)]	6.43%	5.89%

[(a)] Total future cost over an eight year decommissioning period

[(b)] The 6.43% and 5.89% rate of return for KCC and MPSC, respectively, is through 2025. The rates then systematically decrease through 2053 to 0.72% and 2.22% for KCC and MPSC, respectively, based on the assumption that the fund's investment mix will become increasingly conservative as the decommissioning period approaches.

Nuclear Decommissioning Trust Fund

In 2015 and 2014, KCP&L contributed approximately $3.3 million to a tax-qualified trust fund to be used to decommission Wolf Creek. Amounts funded are charged to other operating expense and recovered in customers' rates. The funding level assumes a projected level of return on trust assets. If the actual return on trust assets is below the projected level or actual decommissioning costs are higher than estimated, KCP&L could be responsible for the balance of funds required; however, while there can be no assurances, management believes a rate increase would be allowed to recover decommissioning costs over the remaining life of the unit.

The following table summarizes the change in Great Plains Energy's and KCP&L's nuclear decommissioning trust fund.

	2015	2014
Decommissioning Trust	(millions)	
Beginning balance January 1	$ 199.0	$ 183.9
Contributions	3.3	3.3
Earned income, net of fees	3.4	3.6
Net realized gains	0.7	0.4
Net unrealized gains (losses)	(5.7)	7.8
Ending balance December 31	$ 200.7	$ 199.0

The nuclear decommissioning trust is reported at fair value on the balance sheets and is invested in assets as detailed in the following table.

	December 31							
	2015				2014			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(millions)							
Equity securities	$ 89.6	$ 47.9	$ (2.1)	$ 135.4	$ 87.2	$ 50.6	$ (0.7)	$ 137.1
Debt securities	59.6	2.6	(0.5)	61.7	55.4	3.8	(0.1)	59.1
Other	3.6	—	—	3.6	2.8	—	—	2.8
Total	$ 152.8	$ 50.5	$ (2.6)	$ 200.7	$ 145.4	$ 54.4	$ (0.8)	$ 199.0

The weighted average maturity of debt securities held by the trust at December 31, 2015, was approximately 8 years. The costs of securities sold are determined on the basis of specific identification. The following table summarizes the realized gains and losses from the sale of securities in the nuclear decommissioning trust fund.

	2015	2014	2013
	(millions)		
Realized gains	$ 5.3	$ 1.4	$ 2.4
Realized losses	(4.6)	(1.0)	(0.7)

Nuclear Insurance

The owners of Wolf Creek (Owners) maintain nuclear insurance for Wolf Creek for nuclear liability, nuclear property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear, and war. The nuclear property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for acts of terrorism and related losses, including replacement power costs. There is no industry aggregate limit for liability claims related to terrorism, regardless of the number of acts of terrorism affecting Wolf Creek or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of $3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), the Owners' insurance provider, exists for property claims related to nuclear acts of terrorism, including accidental outage power costs for nuclear acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within twelve months from the date of the first act. An industry aggregate limit of $1.8 billion exists for property claims related to non-nuclear acts of terrorism. These limits plus any recoverable reinsurance are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. In addition, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

In the event of a catastrophic loss at Wolf Creek, the insurance coverage may not be adequate to cover property damage and extra expenses incurred. Uninsured losses, to the extent not recovered through rates, would be

assumed by KCP&L and the other owners and could have a material effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, which was reauthorized through December 31, 2025, by the Energy Policy Act of 2005, the Owners are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently $13.5 billion. This limit of liability consists of the maximum available commercial insurance of $0.4 billion and the remaining $13.1 billion is provided through an industry-wide retrospective assessment program mandated by law, known as the Secondary Financial Protection (SFP) program. Under the SFP program, the Owners can be assessed up to $127.3 million ($59.8 million, KCP&L's 47% share) per incident at any commercial reactor in the country, payable at no more than $19.0 million ($8.9 million, KCP&L's 47% share) per incident per year. This assessment is subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property Insurance

The Owners carry decontamination liability, premature decommissioning liability and property damage insurance from NEIL for Wolf Creek totaling approximately $2.8 billion ($1.3 billion, KCP&L's 47% share). In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the NRC. KCP&L's share of any remaining proceeds can be used for further decontamination, property damage restoration and premature decommissioning costs. Premature decommissioning coverage applies only if an accident at Wolf Creek exceeds $500 million in property damage and decontamination expenses, and only after trust funds have been exhausted.

Accidental Nuclear Outage Insurance

The Owners also carry additional insurance from NEIL to cover costs of replacement power and other extra expenses incurred in the event of a prolonged outage resulting from accidental property damage at Wolf Creek.

Under all NEIL policies, the Owners are subject to retrospective assessments if NEIL losses, for each policy year, exceed the accumulated funds available to the insurer under that policy. The estimated maximum amount of retrospective assessments under the current policies could total approximately $42.2 million ($22.4 million, KCP&L's 47% share) per policy year.

5. REGULATORY MATTERS

KCP&L Kansas Rate Case Proceedings

In January 2015, KCP&L filed an application with KCC to request an increase to its retail revenues of $67.3 million, with a return on equity of 10.3% and a rate-making equity ratio of 50.48%. The request included costs to install environmental upgrades at the La Cygne Station, upgrades at Wolf Creek and other infrastructure and system improvements made to be able to provide reliable electric service.

In September 2015, KCC issued an order for KCP&L authorizing an increase in annual revenues of $48.7 million, a return on equity of 9.3% and a rate-making equity ratio of 50.48%. The rates established by the order took effect on October 1, 2015, and are effective unless and until modified by KCC or stayed by a court. KCP&L filed a Petition for Judicial Review with the Court of Appeals of Kansas in November 2015 regarding various issues.

KCP&L Missouri Rate Case Proceedings
In October 2014, KCP&L filed an application with the MPSC to request an increase to its retail revenues of $120.9 million (subsequently adjusted to $112.7 million), with a return on equity of 10.3% and a rate-making equity ratio of 50.36%. The request included recovery of increased transmission and property tax expenses, costs to install environmental upgrades at the La Cygne Station, upgrades at Wolf Creek and other infrastructure and system improvements made to be able to provide reliable electric service. KCP&L also requested authorization to implement a Fuel Adjustment Clause (FAC).

In September 2015, the MPSC issued an order for KCP&L authorizing an increase in annual revenues of $89.7 million, a return on equity of 9.5% and a rate-making equity ratio of approximately 50.09%. The MPSC also approved KCP&L's request to implement a FAC. The rates established by the order took effect on September 29, 2015, and are effective unless and until modified by the MPSC or stayed by a court. Notices of Appeal of the September 2015 MPSC order were filed with the Missouri Court of Appeals, Western District, by KCP&L in October 2015 and by The Office of the Public Counsel and Midwest Energy Consumers' Group in November 2015 regarding various issues.

GMO Missouri Rate Case Proceedings
In February 2016, GMO filed an application with the MPSC to request an increase to its retail revenues of $59.3 million, with a return on equity of 9.9% and a rate-making equity ratio of 54.83%. The request included recovery of increased transmission and property tax expenses as well as costs for infrastructure and system improvements made to be able to provide reliable electric service.

Regulatory Assets and Liabilities
Great Plains Energy and KCP&L have recorded assets and liabilities on their consolidated balance sheets resulting from the effects of the ratemaking process, which would not otherwise be recorded if the Companies were not regulated. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent future reductions in revenues or refunds to customers.

Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC in KCP&L's and GMO's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to the Companies; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. The Companies' continued ability to meet the criteria for recording regulatory assets and liabilities may be affected in the future by restructuring and deregulation in the electric industry or changes in accounting rules. In the event that the criteria no longer applied to any or all of the Companies' operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism were provided. Additionally, these factors could result in an impairment on utility plant assets.

Great Plains Energy's and KCP&L's regulatory assets and liabilities are detailed in the following table.

	December 31					
	2015			2014		
	KCP&L	GMO	Great Plains Energy	KCP&L	GMO	Great Plains Energy
Regulatory Assets			(millions)			
Taxes recoverable through future rates	$ 125.0	$ 26.4	$ 151.4	$ 107.1	$ 26.3	$ 133.4
Loss on reacquired debt	11.3 [(a)]	2.2 [(a)]	13.5	8.1	2.8	10.9
Cost of removal	12.9	—	12.9	2.8	—	2.8
Asset retirement obligations	57.9	19.5	77.4	38.1	17.2	55.3
Pension and post-retirement costs	358.5 [(b)]	98.9 [(b)]	457.4	430.5	95.4	525.9
Deferred customer programs	50.3 [(c)]	20.8 [(d)]	71.1	50.8	18.8	69.6
Rate case expenses	1.3 [(e)]	—	1.3	1.4	0.1	1.5
Fuel recovery mechanism	16.3 [(e)]	0.1 [(e)]	16.4	13.0	41.0	54.0
Derivative instruments	0.5 [(f)]	6.3 [(f)]	6.8	0.2	2.6	2.8
Iatan No. 1 and common facilities depreciation and carrying costs	14.1 [(g)]	5.2 [(g)]	19.3	14.7	5.5	20.2
Iatan No. 2 construction accounting costs	28.7 [(h)]	16.0 [(h)]	44.7	28.1	15.3	43.4
Kansas property tax surcharge	6.8 [(e)]	—	6.8	6.1	—	6.1
Solar rebates	33.6 [(e)]	49.0 [(e)]	82.6	29.1	56.9	86.0
Transmission delivery charge	1.7 [(e)]	—	1.7	—	—	—
La Cygne deferred depreciation	2.9 [(i)]	—	2.9	—	—	—
Other	10.6 [(e)]	2.3 [(e)]	12.9	15.7	7.0	22.7
Total	$ 732.4	$ 246.7	$ 979.1	$ 745.7	$ 288.9	$ 1,034.6
Regulatory Liabilities						
Emission allowances	$ 66.1	$ —	$ 66.1	$ 70.1	$ —	$ 70.1
Asset retirement obligations	86.5	—	86.5	93.9	—	93.9
Cost of removal	—	68.2 [(j)]	68.2	—	69.7	69.7
Other	12.0	51.6	63.6	8.0	41.0	49.0
Total	$ 164.6	$ 119.8	$ 284.4	$ 172.0	$ 110.7	$ 282.7

(a) Amortized over the life of the related new debt issuances or the remaining lives of the old debt issuances if no new debt was issued.
(b) Represents unrecognized gains and losses, prior service and transition costs that will be recognized in future net periodic pension and post-retirement costs, pension settlements amortized over various periods and financial and regulatory accounting method differences that will be eliminated over the life of the pension plans. Of these amounts, $343.7 million and $54.5 million for KCP&L and GMO, respectively, are not included in rate base and are amortized over various periods.
(c) $8.3 million not included in rate base and amortized over various periods.
(d) $7.4 million not included in rate base and amortized over various periods.
(e) Not included in rate base and amortized over various periods.
(f) Represents fair value of derivative instruments for commodity contracts. Settlements of the contracts are recognized in the income statement and included in fuel recovery mechanisms.
(g) Included in rate base and amortized through 2038.
(h) Included in rate base and amortized through 2058.
(i) Included in rate base and amortized through 2040.
(j) Estimated cumulative net provision for future removal costs.

6. GOODWILL AND INTANGIBLE ASSETS

Accounting rules require goodwill to be tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The annual impairment test for the $169.0 million of GMO acquisition goodwill was conducted on September 1, 2015. The goodwill impairment test is a two step process. The first step compares the fair value of a reporting unit to its carrying amount, including goodwill, to identify potential impairment. If the carrying amount exceeds the fair value of the reporting unit, the second step of the test is performed, consisting of assignment of the reporting unit's fair value to its assets and liabilities to determine an implied fair value of goodwill, which is compared to the carrying amount of goodwill to determine the impairment loss, if any, to be recognized in the financial statements. Great Plains Energy's regulated electric utility operations are considered one reporting unit for assessment of impairment, as they are included within the same operating segment and have similar economic characteristics. The determination of fair value of the reporting unit consisted of two valuation techniques: an income approach consisting of a discounted cash flow analysis and a market approach consisting of a determination of reporting unit invested capital using market multiples derived from the historical revenue, earnings before interest, income taxes, depreciation and amortization (EBITDA), net utility asset values and market prices of stock of peer companies. The results of the two techniques were evaluated and weighted to determine a point within the range that management considered representative of fair value for the reporting unit. Fair value of the reporting unit exceeded the carrying amount, including goodwill; therefore, there was no impairment of goodwill.

Great Plains Energy's and KCP&L's intangible assets are included in electric utility plant on the consolidated balance sheets and are detailed in the following table.

	December 31, 2015		December 31, 2014	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Great Plains Energy	(millions)			
Computer software	$ 333.0	$ (191.8)	$ 300.2	$ (190.9)
Asset improvements	28.3	(6.1)	27.4	(5.5)
KCP&L				
Computer software	$ 315.5	$ (177.7)	$ 277.9	$ (175.5)
Asset improvements	13.1	(1.5)	12.2	(1.3)

Great Plains Energy's and KCP&L's amortization expense related to intangible assets is detailed in the following table.

	2015	2014
	(millions)	
Great Plains Energy	$ 28.6	$ 21.6
KCP&L	24.7	19.2

The following table provides the estimated amortization expense related to Great Plains Energy's and KCP&L's intangible assets for 2016 through 2020 for the intangible assets included in the consolidated balance sheets at December 31, 2015.

	2016	2017	2018	2019	2020
			(millions)		
Great Plains Energy	$ 21.9	$ 18.7	$ 16.5	$ 14.5	$ 12.4
KCP&L	18.9	17.7	16.1	14.1	12.0

7. ASSET RETIREMENT OBLIGATIONS

AROs associated with tangible long-lived assets are legal obligations that exist under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel. These liabilities are recognized at estimated fair value as incurred with a corresponding amount capitalized as part of the cost of the related long-lived assets and depreciated over their useful lives. Accretion of the liabilities due to the passage of time is recorded to a regulatory asset and/or liability. Changes in the estimated fair values of the liabilities are recognized when known.

KCP&L has AROs related to decommissioning Wolf Creek, site remediation of its Spearville Wind Energy Facilities, asbestos abatement, removal of storage tanks and closure and post-closure of ponds and landfills containing coal combustion residuals (CCRs). GMO has AROs related to asbestos abatement, removal of storage tanks and closure and post-closure of ponds and landfills containing CCRs.

Additionally, certain wiring used in Great Plains Energy's and KCP&L's generating stations include asbestos insulation, which would require special handling if disturbed. Due to the inability to reasonably estimate the quantities or the amount of disturbance that will be necessary during dismantlement at the end of the life of a plant, the fair value of this ARO cannot be reasonably estimated at this time. Management will continue to monitor the obligation and will recognize a liability in the period in which sufficient information becomes available to reasonably estimate its fair value.

On April 17, 2015, the Environmental Protection Agency (EPA) published new regulations to regulate the disposal of CCRs at electric generating facilities. See Note 14 under the heading Solid Waste for additional information regarding the CCR rule. The CCR rule represents legal obligations of Great Plains Energy and KCP&L as to the closure and post-closure of its ponds and landfills containing CCRs. As a result of the CCR rule, Great Plains Energy and KCP&L increased their AROs $69.5 million and $51.3 million, respectively, in the second quarter of 2015.

The following table summarizes the change in Great Plains Energy's and KCP&L's AROs.

	Great Plains Energy		KCP&L	
	2015	2014	2015	2014
	(millions)			
Beginning balance	$ 195.9	$ 158.8	$ 177.7	$ 141.7
Additions	54.5	—	34.6	—
Revision in timing and/or estimates	20.5	26.8	22.2	26.8
Settlements	(7.8)	—	(6.7)	—
Accretion	12.8	10.3	11.5	9.2
Ending balance	$ 275.9	$ 195.9	$ 239.3	$ 177.7

8. PENSION PLANS AND OTHER EMPLOYEE BENEFITS

Great Plains Energy maintains defined benefit pension plans for the majority of KCP&L's and GMO's active and inactive employees, including officers, and its 47% ownership share of Wolf Creek Nuclear Operating Corporation (WCNOC) defined benefit plans. For the majority of employees, pension benefits under these plans reflect the employees' compensation, years of service and age at retirement; however, for union employees hired after October 1, 2013, the benefits are derived from a cash balance account formula. Effective in 2014, the non-union plan was closed to future employees. Great Plains Energy also provides certain post-retirement health care and life insurance benefits for substantially all retired employees of KCP&L, GMO and its 47% ownership share of WCNOC.

KCP&L and GMO record pension and post-retirement expense in accordance with rate orders from the MPSC and KCC that allow the difference between pension and post-retirement costs under GAAP and costs for ratemaking to be recognized as a regulatory asset or liability. This difference between financial and regulatory accounting methods is due to timing and will be eliminated over the life of the plans.

In 2014 and 2013, Great Plains Energy incurred pension settlement charges of $8.5 million and $4.9 million, respectively, as a result of accelerated pension distributions.

The following pension benefits tables provide information relating to the funded status of all defined benefit pension plans on an aggregate basis as well as the components of net periodic benefit costs. For financial reporting purposes, the market value of plan assets is the fair value. For regulatory reporting purposes, a five-year smoothing of assets is used to determine fair value. Net periodic benefit costs reflect total plan benefit costs prior to the effects of capitalization and sharing with joint owners of power plants.

	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
Change in projected benefit obligation (PBO)	(millions)			
PBO at January 1	$ 1,186.8	$ 1,007.4	$ 165.2	$ 160.5
Service cost	45.3	36.7	3.3	3.7
Interest cost	50.3	50.1	6.8	7.9
Contribution by participants	—	—	6.9	6.8
Amendments	—	—	(7.1)	—
Actuarial (gain) loss	(59.4)	181.1	(23.6)	(0.3)
Benefits paid	(68.2)	(49.0)	(14.0)	(13.4)
Settlements	—	(39.5)	—	—
PBO at December 31	$ 1,154.8	$ 1,186.8	$ 137.5	$ 165.2
Change in plan assets				
Fair value of plan assets at January 1	$ 730.0	$ 703.0	$ 110.6	$ 101.2
Actual return on plan assets	(16.3)	47.2	(0.1)	4.1
Contributions by employer and participants	76.9	66.2	17.6	18.6
Benefits paid	(66.7)	(46.9)	(13.8)	(13.3)
Settlements	—	(39.5)	—	—
Fair value of plan assets at December 31	$ 723.9	$ 730.0	$ 114.3	$ 110.6
Funded status at December 31	$ (430.9)	$ (456.8)	$ (23.2)	$ (54.6)
Amounts recognized in the consolidated balance sheets				
Non-current asset	$ —	$ —	$ 4.5	$ —
Current pension and other post-retirement liability	(2.6)	(1.9)	(0.8)	(0.9)
Noncurrent pension liability and other post-retirement liability	(428.3)	(454.9)	(26.9)	(53.7)
Net amount recognized before regulatory treatment	(430.9)	(456.8)	(23.2)	(54.6)
Accumulated OCI or regulatory asset/liability	461.2	500.5	(9.4)	26.1
Net amount recognized at December 31	$ 30.3	$ 43.7	$ (32.6)	$ (28.5)
Amounts in accumulated OCI or regulatory asset/liability not yet recognized as a component of net periodic benefit cost:				
Actuarial (gain) loss	$ 230.7	$ 273.5	$ (3.3)	$ 17.5
Prior service cost	3.9	4.7	3.4	13.5
Transition obligation	—	—	—	0.2
Other	226.6	222.3	(9.5)	(5.1)
Net amount recognized at December 31	$ 461.2	$ 500.5	$ (9.4)	$ 26.1

	Pension Benefits			Other Benefits		
	2015	2014	2013	2015	2014	2013
Components of net periodic benefit costs			(millions)			
Service cost	$ 45.3	$ 36.7	$ 41.2	$ 3.3	$ 3.7	$ 4.4
Interest cost	50.3	50.1	47.2	6.8	7.9	7.7
Expected return on plan assets	(51.7)	(50.2)	(47.1)	(2.9)	(2.6)	(2.0)
Prior service cost	0.8	0.9	2.0	3.1	3.1	7.2
Recognized net actuarial (gain) loss	51.4	50.0	54.3	0.2	(0.1)	1.7
Transition obligation				0.2	0.2	0.2
Settlement charges		8.5	4.9			
Net periodic benefit costs before regulatory adjustment	96.1	96.0	102.5	10.7	12.2	19.2
Regulatory adjustment	(9.8)	(11.3)	(16.8)	4.4	4.3	(2.4)
Net periodic benefit costs	86.3	84.7	85.7	15.1	16.5	16.8
Other changes in plan assets and benefit obligations recognized in OCI or regulatory assets/liabilities						
Current year net (gain) loss	8.6	175.8	(147.0)	(20.6)	(1.8)	(22.1)
Amortization of gain (loss)	(51.4)	(50.0)	(54.3)	(0.2)	0.1	(1.7)
Prior service cost	—	—	0.3	(7.0)	—	(6.0)
Amortization of prior service cost	(0.8)	(0.9)	(2.0)	(3.1)	(3.1)	(7.2)
Amortization of transition obligation	—	—	—	(0.2)	(0.2)	(0.2)
Other regulatory activity	4.3	7.3	11.8	(4.4)	(4.2)	2.1
Total recognized in OCI or regulatory asset/liability	(39.3)	132.2	(191.2)	(35.5)	(9.2)	(35.1)
Total recognized in net periodic benefit costs and OCI or regulatory asset/liability	$ 47.0	$ 216.9	$ (105.5)	$ (20.4)	$ 7.3	$ (18.3)

For financial reporting purposes, the estimated prior service cost and net loss for the defined benefit plans that will be amortized from accumulated other comprehensive income (OCI) or a regulatory asset into net periodic benefit cost in 2016 are $0.7 million and $51.8 million, respectively. For financial reporting purposes, net actuarial gains and losses are recognized on a rolling five-year average basis. For regulatory reporting purposes, net actuarial gains and losses are amortized over ten years. The estimated prior service cost and net gain for the other post-retirement benefit plans that will be amortized from accumulated OCI or a regulatory asset into net periodic benefit cost in 2016 are $1.2 million and $1.5 million, respectively.

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $1,017.6 million and $1,036.8 million at December 31, 2015, and 2014, respectively. Pension and other post-retirement benefit plans with the PBO, ABO or accumulated other post-retirement benefit obligation (APBO) in excess of the fair value of plan assets at year-end are detailed in the following table.

	2015	2014
Pension plans with the PBO in excess of plan assets	(millions)	
Projected benefit obligation	$ 1,154.8	$ 1,186.8
Fair value of plan assets	723.9	730.0
Pension plans with the ABO in excess of plan assets		
Accumulated benefit obligation	$ 1,017.6	$ 1,036.8
Fair value of plan assets	723.9	730.0
Other post-retirement benefit plans with the APBO in excess of plan assets		
Accumulated other post-retirement benefit obligation	$ 108.5	$ 165.2
Fair value of plan assets	80.8	110.6

The GMO Supplemental Executive Retirement Plan (SERP) is reflected as an unfunded ABO of $22.9 million. Great Plains Energy has approximately $16.4 million of assets in a non-qualified trust for this plan as of December 31, 2015, and expects to fund future benefit payments from these assets.

The expected long-term rate of return on plan assets represents Great Plains Energy's estimate of the long-term return on plan assets and is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolios. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns of various asset classes. Based on the target asset allocation for each asset class, the overall expected rate of return for the portfolios was developed and adjusted for the effect of projected benefits paid from plan assets and future plan contributions. The following tables provide the weighted-average assumptions used to determine benefit obligations and net costs.

Weighted-average assumptions used to determine the benefit obligation at December 31	Pension Benefits 2015	Pension Benefits 2014	Other Benefits 2015	Other Benefits 2014
Discount rate	4.54%	4.22%	4.47%	4.14%
Rate of compensation increase	3.62%	3.62%	3.50%	3.50%

Weighted-average assumptions used to determine net costs for years ended December 31	Pension Benefits 2015	Pension Benefits 2014	Other Benefits 2015	Other Benefits 2014
Discount rate	4.22%	5.03%	4.14%	4.92%
Expected long-term return on plan assets	7.14%	7.24%	2.81% *	2.70% *
Rate of compensation increase	3.62%	3.69%	3.50%	3.50%

*after tax

Great Plains Energy expects to contribute $75.7 million to the pension plans in 2016 to meet Employee Retirement Income Security Act of 1974, as amended (ERISA) funding requirements and regulatory orders, the majority of which is expected to be paid by KCP&L. Great Plains Energy's funding policy is to contribute amounts sufficient to meet the ERISA funding requirements and MPSC and KCC rate orders plus additional amounts as considered appropriate; therefore, actual contributions may differ from expected contributions. Great Plains Energy also expects to contribute $5.1 million to other post-retirement benefit plans in 2016, the majority of which is expected to be paid by KCP&L.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid through 2025:

	Pension Benefits	Other Benefits
	(millions)	
2016	$ 81.2	$ 8.2
2017	77.2	8.8
2018	77.4	9.5
2019	80.5	10.2
2020	82.5	10.8
2021-2025	427.3	60.4

Pension plan assets are managed in accordance with prudent investor guidelines contained in the ERISA requirements. The investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets within a reasonable and prudent level of risk. The portfolios are invested, and periodically rebalanced, to achieve targeted allocations of approximately 33% U.S. large cap and small cap equity securities, 20% international equity securities, 35% fixed income securities, 7% real estate, 1% commodities and 4% hedge funds. Fixed income securities include domestic and foreign corporate bonds, collateralized mortgage obligations and asset-backed securities, U.S. government agency, state and local obligations, U.S. Treasury notes and money market funds.

The fair values of Great Plains Energy's pension plan assets at December 31, 2015 and 2014, by asset category are in the following tables.

		Fair Value Measurements Using			
Description	December 31 2015	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets measured at NAV
			(millions)		
Pension Plans					
Equity securities					
U.S. [(a)]	$ 226.0	$ 195.5	$ —	$ —	$ 30.5
International [(b)]	147.4	109.7	—	—	37.7
Real estate [(c)]	45.9	12.2	—	—	33.7
Commodities [(d)]	5.8				5.8
Fixed income securities					
Fixed income funds [(e)]	60.4	20.0			40.4
U.S. Treasury	48.8	48.8			
U.S. Agency, state and local obligations	19.0		19.0		
U.S. corporate bonds [(f)]	108.8		108.8		
Foreign corporate bonds	10.2		10.2		
Hedge funds [(g)]	23.7				23.7
Cash equivalents	26.0	26.0			
Other	1.9		1.9		
Total	$ 723.9	$ 412.2	$ 139.9	$ —	$ 171.8

Description	December 31, 2014	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets measured at NAV
Pension Plans			(millions)		
Equity securities					
U.S. [(a)]	$ 235.2	$ 203.6	$ —	$ —	$ 31.6
International [(b)]	147.3	108.4	0.3	—	38.6
Real estate [(c)]	38.9	7.7	—	—	31.2
Commodities [(d)]	5.9	—	—	—	5.9
Fixed income securities					
Fixed income funds [(e)]	66.1	22.3	—	—	43.8
U.S. Treasury	44.2	44.2	—	—	—
U.S. Agency, state and local obligations	21.0	—	21.0	—	—
U.S. corporate bonds [(f)]	109.0	—	109.0	—	—
Foreign corporate bonds	13.6	—	13.6	—	—
Hedge funds [(g)]	24.1	—	—	—	24.1
Cash equivalents	16.7	16.7	—	—	—
Other	8.0	—	8.0	—	—
Total	$ 730.0	$ 402.9	$ 151.9	$ —	$ 175.2

[(a)] At December 31, 2015 and 2014, this category is comprised of $121.6 million and $78.1 million, respectively, of traded mutual funds valued at daily listed prices and $73.9 million and $125.5 million, respectively, of traded common stocks and exchange traded funds. At December 31, 2015 and 2014, this category also includes $30.5 million and $31.6 million, respectively, of institutional common/collective trust funds valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[(b)] At December 31, 2015 and 2014, this category is comprised of $34.2 million and $38.6 million, respectively, of traded mutual funds valued at daily listed prices and $75.5 million and $70.1 million, respectively, of traded American depository receipts, global depository receipts and ordinary shares. At December 31, 2015 and 2014, this category also includes $37.7 million and $38.6 million, respectively, of institutional common/collective trust funds valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[(c)] At December 31, 2015 and 2014, this category is comprised of $12.2 million and $7.7 million, respectively, of traded real estate investment trusts. At December 31, 2015 and 2014, this category also includes $33.7 million and $31.2 million, respectively, of institutional common/collective trust funds and a limited partnership valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[(d)] Consists of institutional common/collective trust funds valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[(e)] At December 31, 2015 and 2014, this category is comprised of $20.0 million and $22.3 million, respectively, of traded mutual funds valued at daily listed prices. At December 31, 2015 and 2014, this category also includes $40.4 million and $43.8 million, respectively, of institutional common/collective trust funds valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[(f)] At December 31, 2015 and 2014, this category is comprised of $103.0 million and $100.3 million, respectively, of corporate bonds, $2.9 million and $4.0 million, respectively, of collateralized mortgage obligations and $2.9 million and $4.7 million, respectively, of other asset-backed securities.

[(g)] Consists of closely-held limited partnerships valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

Other post-retirement plan assets are also managed in accordance with prudent investor guidelines contained in the ERISA requirements. The investment strategy supports the objective of the funds, which is to preserve capital, maintain sufficient liquidity and earn a consistent rate of return. Other post-retirement plan assets are invested primarily in fixed income securities, which may include domestic and foreign corporate bonds, collateralized mortgage obligations and asset-backed securities, U.S. government agency, state and local obligations, U.S. Treasury notes and money market funds, as well as domestic and international equity funds.

The fair values of Great Plains Energy's other post-retirement plan assets at December 31, 2015 and 2014, by asset category are in the following tables.

Description	December 31 2015	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets measured at NAV
Other Post-Retirement Benefit Plans			(millions)		
Equity securities	$ 3.2	$ 3.2	$ —	$ —	$ —
Fixed income securities					
Fixed income fund[(a)]	68.9	0.1	—	—	68.8
U.S. Treasury	3.9	3.9	—	—	—
U.S. Agency, state and local obligations	5.4	—	5.4	—	—
U.S. corporate bonds[(b)]	15.6	—	15.6	—	—
Foreign corporate bonds	1.6	—	1.6	—	—
Cash equivalents	14.0	14.0	—	—	—
Other	1.7	—	1.7	—	—
Total	$ 114.3	$ 21.2	$ 24.3	$ —	$ 68.8

Description	December 31 2014	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets measured at NAV
Other Post-Retirement Benefit Plans			(millions)		
Equity securities	$ 3.2	$ 3.2	$ —	$ —	$ —
Fixed income securities					
Fixed income fund[(a)]	73.0	0.2	—	—	72.8
U.S. Treasury	2.7	2.7	—	—	—
U.S. Agency, state and local obligations	4.9	—	4.9	—	—
U.S. corporate bonds[(b)]	13.0	—	13.0	—	—
Foreign corporate bonds	1.5	—	1.5	—	—
Cash equivalents	10.4	10.4	—	—	—
Other	1.9	—	1.9	—	—
Total	$ 110.6	$ 16.5	$ 21.3	$ —	$ 72.8

(a) At December 31, 2015 and 2014 this category is comprised of $0.1 million and $0.2 million, respectively, of traded mutual funds valued at daily listed prices. At December 31, 2015 and 2014 this category also includes $68.8 million and $72.8 million, respectively, of an institutional common/collective trust fund valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

(b) At December 31, 2015 and 2014, this category is comprised of $12.6 million and $10.3 million, respectively, of corporate bonds, $0.6 million and $0.8 million, respectively, of collateralized mortgage obligations and $2.4 million and $1.9 million, respectively, of other asset-backed securities.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The cost trend assumed for 2015 and 2016 was 7.0% and 6.8%, respectively, with the rate declining through 2025 to the ultimate cost trend rate of 4.5%.

The effects of a one-percentage point change in the assumed health care cost trend rates, holding all other assumptions constant, at December 31, 2015, are detailed in the following table.

	Increase	Decrease
	(millions)	
Effect on total service and interest component	$ 0.9	$ (1.1)
Effect on post-retirement benefit obligation	4.0	(3.6)

Employee Savings Plans

Great Plains Energy has defined contribution savings plans (401(k)) that cover substantially all employees. Great Plains Energy matches employee contributions, subject to limits. The annual cost of the plans was approximately $10.6 million in 2015, $9.7 million in 2014 and $9.6 million in 2013. KCP&L's annual cost of the plans was approximately $7.9 million in 2015, $7.1 million in 2014 and $7.0 million in 2013.

9. EQUITY COMPENSATION

Great Plains Energy's Long-Term Incentive Plan is an equity compensation plan approved by Great Plains Energy's shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, restricted stock units, bonus shares, stock options, stock appreciation rights, limited stock appreciation rights, director shares, director deferred share units and performance shares to directors, officers and other employees of Great Plains Energy and KCP&L. The maximum number of shares of Great Plains Energy common stock that can be issued under the plan is 8.0 million. Common stock shares delivered by Great Plains Energy under the Long-Term Incentive Plan may be authorized but unissued, held in the treasury or purchased on the open market (including private purchases) in accordance with applicable securities laws. Great Plains Energy has a policy of delivering newly issued shares, or shares surrendered by Long-Term Incentive Plan participants for the withholding of taxes and held in treasury, or both, and does not expect to repurchase common shares during 2016 to satisfy performance share payments and director deferred share unit conversion. Forfeiture rates are based on historical forfeitures and future expectations and are reevaluated annually.

The following table summarizes Great Plains Energy's and KCP&L's equity compensation expense and the associated income tax benefit.

	2015	2014	2013
Great Plains Energy		(millions)	
Equity compensation expense	$ 4.0	$ 9.9	$ 5.6
Income tax benefit	1.4	3.6	1.9
KCP&L			
Equity compensation expense	$ 2.6	$ 6.9	$ 4.0
Income tax benefit	0.9	2.4	1.3

Performance Shares

The payment of performance shares is contingent upon achievement of specific performance goals over a stated period of time as approved by the Compensation and Development Committee of the Board. The number of performance shares ultimately paid can vary from the number of shares initially granted depending on Great Plains Energy's performance over stated performance periods. Compensation expense for performance shares is calculated by taking the change in fair value between reporting periods for the portion for which the requisite service has been rendered. Dividends are accrued over the vesting period and paid in cash based on the number of performance shares ultimately paid.

The fair value of performance share awards is estimated using the market value of the Company's stock at the valuation date and a Monte Carlo simulation technique that incorporates assumptions for inputs of expected volatilities, dividend yield and risk-free rates. Expected volatility is based on daily stock price change during a

historical period commensurate with the remaining term of the performance period of the grant. The risk-free rate is based upon the rate at the time of the evaluation for zero-coupon government bonds with a maturity consistent with the remaining performance period of the grant. The dividend yield is based on the most recent dividends paid and the actual closing stock price on the valuation date. For shares granted in 2015, inputs for expected volatility, dividend yield and risk-free rates ranged from 16%-17%, 3.72%-4.03% and 0.86%-1.02%, respectively.

Performance share activity is summarized in the following table. Performance adjustment represents the number of shares of common stock related to performance shares ultimately issued that can vary from the number of performance shares initially granted depending on Great Plains Energy's performance over a stated period of time.

	Performance Shares	Grant Date Fair Value*
Beginning balance January 1, 2015	534,016	$ 25.11
Granted	232,838	24.03
Earned	(25,844)	19.48
Forfeited	(54,485)	25.68
Performance adjustment	(77,515)	19.48
Ending balance December 31, 2015	609,010	25.60

* weighted-average

At December 31, 2015, the remaining weighted-average contractual term was 1.0 year. The weighted-average grant-date fair value of shares granted was $24.03, $28.78 and $24.17 in 2015, 2014 and 2013, respectively. At December 31, 2015, there was $5.9 million of total unrecognized compensation expense, net of forfeiture rates, related to performance shares granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. The total fair value of performance shares earned and paid was $0.5 million, $2.8 million and $2.4 million in 2015, 2014 and 2013, respectively.

Restricted Stock

Restricted stock cannot be sold or otherwise transferred by the recipient prior to vesting and has a value equal to the fair market value of the shares on the issue date. Restricted stock shares vest over a stated period of time with accruing reinvested dividends subject to the same restrictions. Compensation expense, calculated by multiplying shares by the grant-date fair value related to restricted stock, is recognized over the stated vesting period. Restricted stock activity is summarized in the following table.

	Nonvested Restricted Stock	Grant Date Fair Value*
Beginning balance January 1, 2015	267,390	$ 22.31
Granted and issued	92,780	25.89
Vested	(110,496)	19.71
Forfeited	(18,166)	24.81
Ending balance December 31, 2015	231,508	24.78

* weighted-average

At December 31, 2015, the remaining weighted-average contractual term was 1.3 years. The weighted-average grant-date fair value of shares granted was $25.89, $25.70 and $22.47 in 2015, 2014 and 2013, respectively. At December 31, 2015, there was $2.4 million of total unrecognized compensation expense, net of forfeiture rates, related to nonvested restricted stock granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. Total fair value of shares vested was $2.2 million, $1.9 million and $1.2 million in 2015, 2014 and 2013, respectively.

Director Deferred Share Units
Non-employee directors receive shares of Great Plains Energy's common stock as part of their annual retainer. Each director may elect to defer receipt of their shares by receiving Director Deferred Share Units that convert to shares of Great Plains Energy's common stock at the end of January in the year after they leave the Board or such other time as elected by each director. Director Deferred Share Units have a value equal to the market value of Great Plains Energy's common stock on the grant date with accruing dividends. Compensation expense, calculated by multiplying the director deferred share units by the related grant-date fair value, is recognized at the grant date. The total fair value of shares of Director Deferred Share Units issued was insignificant for 2015 and 2014. Director Deferred Share Units activity is summarized in the following table.

	Share Units	Grant Date Fair Value*
Beginning balance January 1, 2015	110,741	$ 21.98
Issued	24,576	26.15
Converted	(19,902)	21.50
Ending balance December 31, 2015	115,415	22.95

* weighted-average

10. SHORT-TERM BORROWINGS AND SHORT-TERM BANK LINES OF CREDIT

Great Plains Energy's $200 Million Revolving Credit Facility
Great Plains Energy's $200 million revolving credit facility with a group of banks expires in October 2019. The facility's terms permit transfers of unused commitments between this facility and the KCP&L and GMO facilities discussed below, with the total amount of the facility not exceeding $400 million at any one time. A default by Great Plains Energy or any of its significant subsidiaries on other indebtedness totaling more than $50.0 million is a default under the facility. Under the terms of this facility, Great Plains Energy is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At December 31, 2015, Great Plains Energy was in compliance with this covenant. At December 31, 2015, Great Plains Energy had $10.0 million of outstanding cash borrowings at a weighted-average interest rate of 1.94% and had issued $0.2 million in letters of credit under the credit facility. At December 31, 2014, Great Plains Energy had $4.0 million of outstanding cash borrowings at a weighted-average interest rate of 1.69% and had issued no letters of credit under the credit facility.

KCP&L's $600 Million Revolving Credit Facility and Commercial Paper
KCP&L's $600 million revolving credit facility with a group of banks provides support for its issuance of commercial paper and other general corporate purposes and expires in October 2019. Great Plains Energy and KCP&L may transfer up to $200 million of unused commitments between Great Plains Energy's and KCP&L's facilities. A default by KCP&L on other indebtedness totaling more than $50.0 million is a default under the facility. Under the terms of this facility, KCP&L is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At December 31, 2015, KCP&L was in compliance with this covenant. At December 31, 2015, KCP&L had $180.3 million of commercial paper outstanding at a weighted-average interest rate of 0.70%, had issued letters of credit totaling $2.7 million and had no outstanding cash borrowings under the credit facility. At December 31, 2014, KCP&L had $358.3 million of commercial paper outstanding at a weighted-average interest rate of 0.48%, had issued letters of credit totaling $2.7 million and had no outstanding cash borrowings under the credit facility.

GMO's $450 Million Revolving Credit Facility and Commercial Paper

GMO's $450 million revolving credit facility with a group of banks provides support for its issuance of commercial paper and other general corporate purposes and expires in October 2019. Great Plains Energy and GMO may transfer up to $200 million of unused commitments between Great Plains Energy's and GMO's facilities. A default by GMO or any of its significant subsidiaries on other indebtedness totaling more than $50.0 million is a default under the facility. Under the terms of this facility, GMO is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At December 31, 2015, GMO was in compliance with this covenant. At December 31, 2015, GMO had $43.7 million of commercial paper outstanding at a weighted-average interest rate of 0.65%, had issued letters of credit totaling $2.5 million and had no outstanding cash borrowings under the credit facility. At December 31, 2014, GMO had no commercial paper outstanding, had issued letters of credit totaling $3.2 million and had no outstanding cash borrowings under the credit facility.

11. LONG-TERM DEBT

Great Plains Energy's and KCP&L's long-term debt is detailed in the following table.

	Year Due	December 31 2015	2014
KCP&L		(millions)	
General Mortgage Bonds			
2.47% EIRR bonds[a]	2017-2035	$ 110.5	$ 146.4
7.15% Series 2009A (8.59% rate)[b]	2019	400.0	400.0
4.65% EIRR Series 2005	2035	—	50.0
Senior Notes			
5.85% Series (5.72% rate)[b]	2017	250.0	250.0
6.375% Series (7.49% rate)[b]	2018	350.0	350.0
3.15% Series	2023	300.0	300.0
3.65% Series	2025	350.0	—
6.05% Series (5.78% rate)[b]	2035	250.0	250.0
5.30% Series	2041	400.0	400.0
EIRR Bonds			
0.01% Series 2007A and 2007B[c]	2035	146.5	146.5
2.875% Series 2008	2038	23.4	23.4
Current maturities		—	(14.0)
Unamortized discount and debt issuance costs		(17.3)	(19.5)
Total KCP&L excluding current maturities[d]		2,563.1	2,282.8
Other Great Plains Energy			
GMO First Mortgage Bonds 9.44% Series	2016-2021	6.8	7.9
GMO Senior Notes			
8.27% Series	2021	80.9	80.9
3.49% Series A	2025	125.0	125.0
4.06% Series B	2033	75.0	75.0
4.74% Series C	2043	150.0	150.0
GMO Medium Term Notes			
7.33% Series	2023	3.0	3.0
7.17% Series	2023	7.0	7.0
Great Plains Energy Senior Notes			
6.875% Series (7.33% rate)[b]	2017	100.0	100.0
4.85% Series	2021	350.0	350.0
5.292% Series	2022	287.5	287.5
Current maturities		(1.1)	(1.1)
Unamortized discount and premium, net and debt issuance costs		(2.1)	(2.3)
Total Great Plains Energy excluding current maturities[d]		$ 3,745.1	$ 3,465.7

(a) Weighted-average interest rates at December 31, 2015

(b) Rate after amortizing gains/losses recognized in OCI on settlements of interest rate hedging instruments

(c) Variable rate

(d) At December 31, 2015, does not include $50.0 million and $21.9 million of secured Series 2005 Environmental Improvement Revenue Refunding (EIRR) bonds because the bonds were repurchased in September 2015 and are held by KCP&L.

Amortization of Debt Expense

Great Plains Energy's and KCP&L's amortization of debt expense is detailed in the following table.

	2015	2014	2013
	(millions)		
KCP&L	$ 3.0	$ 3.0	$ 3.2
Other Great Plains Energy	1.1	1.8	2.5
Total Great Plains Energy	$ 4.1	$ 4.8	$ 5.7

KCP&L General Mortgage Bonds

KCP&L has issued mortgage bonds under the General Mortgage Indenture and Deed of Trust dated December 1, 1986, as supplemented (Indenture). The Indenture creates a mortgage lien on substantially all of KCP&L's utility plant. Mortgage bonds totaling $510.5 million and $596.4 million were outstanding at December 31, 2015 and 2014, respectively.

In March 2015, KCP&L repaid its $14.0 million secured Series 2005 EIRR bonds at maturity.

In September 2015, KCP&L purchased in lieu of redemption its $50.0 million and $21.9 million secured EIRR Series 2005 bonds. As of December 31, 2015, the bonds were still outstanding, but were not reported as a liability on the balance sheet since they are being held by KCP&L. KCP&L has the ability to remarket these bonds to third parties whenever it determines market conditions are sufficiently attractive to do so.

KCP&L Municipal Bond Insurance Policies

KCP&L's secured Series 2005 EIRR bonds totaling $50.0 million and $21.9 million, respectively, are covered by a municipal bond insurance policy between KCP&L and Syncora Guarantee, Inc. (Syncora). The insurance agreements between KCP&L and Syncora provide for reimbursement by KCP&L for any amounts that Syncora pays under the municipal bond insurance policies. The insurance agreements contain a covenant that the indebtedness to total capitalization ratio of KCP&L and its consolidated subsidiaries will not be greater than 0.68 to 1.00. At December 31, 2015, KCP&L was in compliance with this covenant. KCP&L is also restricted from issuing additional bonds under its General Mortgage Indenture if, after giving effect to such additional bonds, the proportion of secured debt to total indebtedness would be more than 75%, or more than 50% if the long term rating for such bonds by Standard & Poor's or Moody's Investors Service would be at or below A- or A3, respectively. The insurance agreement covering the unsecured Series 2005 EIRR bonds also required KCP&L to provide collateral to Syncora in the form of $50.0 million of Mortgage Bonds Series 2005 EIRR Insurer due 2035 for KCP&L's obligations under the insurance agreement as a result of KCP&L issuing general mortgage bonds in 2009 (other than refunding of outstanding general mortgage bonds) that resulted in the aggregate amount of outstanding general mortgage bonds exceeding 10% of total capitalization. The bonds are not incremental debt for KCP&L but collateralize Syncora's claim on KCP&L if Syncora was required to meet its obligation under the insurance agreement. In the event of a default under the insurance agreements, Syncora may take any available legal or equitable action against KCP&L, including seeking specific performance of the covenants.

KCP&L Senior Notes

In August 2015, KCP&L issued, at a discount, $350.0 million of 3.65% unsecured Senior Notes, maturing in 2025.

GMO First Mortgage Bonds

GMO has issued mortgage bonds under the General Mortgage Indenture and Deed of Trust dated April 1, 1946, as supplemented. The Indenture creates a mortgage lien on substantially all of GMO's St. Joseph Light & Power division utility plant. Mortgage bonds totaling $6.8 million and $7.9 million, respectively, were outstanding at December 31, 2015 and 2014.

GMO Senior Notes

Under the terms of the note purchase agreement for GMO's Series A, B and C Senior Notes, GMO is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the agreement, not greater than 0.65 to 1.00 at all times. In addition, GMO's priority debt, as defined in the agreement, cannot exceed 15% of consolidated tangible net worth, as defined in the agreement. At December 31, 2015, GMO was in compliance with these covenants.

Scheduled Maturities

Great Plains Energy's and KCP&L's long-term debt maturities for the next five years are detailed in the following table.

	2016	2017	2018	2019	2020
			(millions)		
Great Plains Energy	$ 1.1	$ 382.1	$ 351.1	$ 401.1	$ 1.1
KCP&L	—	281.0	350.0	400.0	—

12. COMMON SHAREHOLDERS' EQUITY

Great Plains Energy has an effective shelf registration statement for the sale of unlimited amounts of securities with the Securities and Exchange Commission (SEC) that became effective in March 2015 and expires in March 2018.

Great Plains Energy has 7.0 million shares of common stock registered with the SEC for its Dividend Reinvestment and Direct Stock Purchase Plan. The plan allows for the purchase of common shares by reinvesting dividends or making optional cash payments. Great Plains Energy can issue new shares or purchase shares on the open market for the plan. At December 31, 2015, 2.1 million shares remained available for future issuances.

Great Plains Energy has 14.3 million shares of common stock registered with the SEC for a defined contribution savings plan (401(k)). Shares issued under the plan may be either newly issued shares or shares purchased in the open market. At December 31, 2015, 1.0 million shares remained available for future issuances.

Treasury shares are held for future distribution upon issuance of shares in conjunction with the Company's Long-Term Incentive Plan.

Great Plains Energy's articles of incorporation restrict the payment of common stock dividends in the event common equity is 25% or less of total capitalization. In addition, if preferred stock dividends are not declared and paid when scheduled, Great Plains Energy could not declare or pay common stock dividends or purchase any common shares. If the unpaid preferred stock dividends equal four or more full quarterly dividends, the preferred shareholders, voting as a single class, could elect the smallest number of directors necessary to constitute a majority of the full Board. Certain conditions in the MPSC and KCC orders authorizing the holding company structure require Great Plains Energy and KCP&L to maintain consolidated common equity of at least 30% and 35%, respectively, of total capitalization (including only the amount of short-term debt in excess of the amount of construction work in progress). Under the Federal Power Act, KCP&L and GMO generally can pay dividends only out of retained earnings. The revolving credit agreements of Great Plains Energy, KCP&L and GMO and the note purchase agreement for GMO's Series A, B and C Senior Notes contain a covenant requiring the respective company to maintain a consolidated indebtedness to consolidated total capitalization ratio of not more than 0.65 to 1.00 at all times.

As of December 31, 2015, all of Great Plains Energy's and KCP&L's retained earnings and net income were free of restrictions. As a result of the above restrictions, Great Plains Energy's subsidiaries had restricted net assets of approximately $2.8 billion as of December 31, 2015. The restrictions are not expected to affect the Companies' ability to pay dividends at the current level in the foreseeable future.

13. PREFERRED STOCK

At December 31, 2015, 1.6 million shares of Cumulative No Par Preferred Stock, 390,000 shares of Cumulative Preferred Stock, $100 par value and 11.0 million shares of no par Preference Stock were authorized under Great Plains Energy's articles of incorporation. All of the 390,000 authorized shares of Cumulative Preferred Stock are issued and outstanding. Great Plains Energy has the option to redeem the $39.0 million of issued Cumulative Preferred Stock at prices ranging from 101% to 103.7% of par value. If Great Plains Energy voluntarily files for dissolution or liquidation, the Cumulative Preferred Stock holders are entitled to receive the redemption prices. If a proceeding for dissolution or liquidation is filed against Great Plains Energy, the Cumulative Preferred Stock holders are entitled to receive the $100 par value per share plus accrued and unpaid dividends.

14. COMMITMENTS AND CONTINGENCIES

Environmental Matters

Great Plains Energy and KCP&L are subject to extensive federal, state and local environmental laws, regulations and permit requirements relating to air and water quality, waste management and disposal, natural resources and health and safety. In addition to imposing continuing compliance obligations and remediation costs, these laws, regulations and permits authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is expected to be material to Great Plains Energy and KCP&L. Failure to comply with environmental requirements or to timely recover environmental costs through rates could have a material effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Great Plains Energy's and KCP&L's current estimates of capital expenditures (exclusive of AFUDC) and property taxes) over the next five years to comply with environmental regulations are in the following table. The total cost of compliance with any existing, proposed or future laws and regulations may be significantly different from these cost estimates provided.

		2016		2017		2018		2019		2020
					(millions)					
Great Plains Energy	$	99.6	$	45.5	$	20.6	$	98.9	$	151.9
KCP&L		83.8		30.1		14.4		87.3		130.0

The Companies expect to seek recovery of the costs associated with environmental requirements through rate increases; however, there can be no assurance that such rate increases would be granted. The Companies may be subject to materially adverse rate treatment in response to competitive, economic, political, legislative or regulatory factors and/or public perception of the Companies' environmental reputation.

The following discussion groups environmental and certain associated matters into the broad categories of air and climate change, water, solid waste and remediation.

Clean Air Act and Climate Change Overview

The Clean Air Act Amendments of 1990 (Clean Air Act) and associated regulations enacted by the EPA form a comprehensive program to preserve and enhance air quality. States are required to establish regulations and programs to address all requirements of the Clean Air Act and have the flexibility to enact more stringent requirements. All of Great Plains Energy's and KCP&L's generating facilities, and certain of their other facilities, are subject to the Clean Air Act.

Mercury and Air Toxics Standards (MATS) Rule

In December 2011, the EPA finalized the MATS Rule that will reduce emissions of toxic air pollutants, also known as hazardous air pollutants, from new and existing coal- and oil-fired electric utility generating units with a capacity of greater than 25 MWs. The rule establishes numerical emission limits for mercury, particulate matter (a surrogate for non-mercury metals) and hydrochloric acid (a surrogate for acid gases). The rule establishes work practices, instead of numerical emission limits, for organic air toxics,

including dioxin/furan. KCP&L's and GMO's affected coal-fired units currently comply or will be compliant in April 2016. Estimated capital costs to comply with the MATS Rule are included in the estimated capital expenditures table above.

Industrial Boiler Rule

In December 2012, the EPA issued a final rule that would reduce emissions of hazardous air pollutants from new and existing industrial boilers. The final rule establishes numeric emission limits for mercury, particulate matter (as a surrogate for non-mercury metals), hydrogen chloride (as a surrogate for acid gases) and carbon monoxide (as a surrogate for non-dioxin organic hazardous air pollutants). The final rule establishes emission limits for KCP&L's and GMO's existing units that produce steam other than for the generation of electricity. The final rule does not apply to KCP&L's and GMO's electricity generating boilers, but would apply to most of GMO's Lake Road boilers, which also serve steam customers, and to auxiliary boilers at other generating facilities. KCP&L's and GMO's affected units currently comply or will be compliant in January 2017. Estimated capital costs to comply with the Industrial Boiler Rule are included in the estimated capital expenditures table above.

Climate Change

The Companies' current generation capacity is primarily coal-fired and is estimated to produce about one ton of carbon dioxide (CO_2) per MWh, or approximately 21 million tons and 15 million tons per year for Great Plains Energy and KCP&L, respectively. The Companies are subject to existing greenhouse gas reporting regulations and certain greenhouse gas requirements. Federal or state legislation concerning the reduction of emissions of greenhouse gases, including CO_2, could be enacted in the future. At the international level, in December 2015 the Paris Agreement was adopted by nearly 200 countries. The Paris Agreement did not result in any new, legally binding obligations on the United States to meet a particular greenhouse gas emissions target, but establishes a framework for international cooperation on climate change. International agreements legally binding on the United States may be reached in the future. Greenhouse gas legislation has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L; however, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until such legislation is passed. In the absence of new Congressional mandates, the EPA is proceeding with the regulation of greenhouse gases under the existing Clean Air Act.

In August 2015, the EPA finalized CO_2 emission standards for new, modified and reconstructed affected fossil-fuel-fired electric utility generating units. The standards would not apply to Great Plains Energy's and KCP&L's existing units unless the units were modified or reconstructed in the future.

In August 2015, the EPA finalized its Clean Power Plan which sets CO_2 emission performance rates for existing affected fossil fuel-fired electric generating units. Specifically, the EPA translated those performance rates into a state goal measured in mass and rate based on each state's generation mix. The states have the ability to develop their own plans for affected units to achieve either the performance rates directly or the state goals, with guidelines for the development, submittal and implementation of those plans. Nationwide, by 2030, the EPA projects the Clean Power Plan would achieve CO_2 emission reductions from the power sector of approximately 32% from CO_2 emission levels in 2005.

The EPA has finalized an interim CO_2 goal rate reduction in Kansas and Missouri (average of 2022-2029) of 34% and 26%, respectively, and 2030 targets in Kansas and Missouri of 44% and 37%, respectively. The baseline for these reductions is 2012 CO_2 emissions adjusted by the EPA. The EPA has also finalized mass based CO_2 reduction goals.

States are required to submit plans to implement the Clean Power Plan. An EPA plan with either a rate-based or mass-based trading program has yet to be finalized and can be enforced in states that fail to submit approved plans.

In February 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan putting the rule on hold pending review in the United States Court of Appeals for the District of Columbia Circuit and any subsequent review by the U.S. Supreme Court if such review is sought. Compliance with the Clean Power Plan has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L; however, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until the outcome of pending litigation is known and/or the state plans to implement the Clean Power Plan are known.

The Companies are subject to existing renewable energy standards in Missouri. Management believes that national renewable energy standards are also possible. The timing, provisions and impact of such possible future requirements, including the cost to obtain and install new equipment to achieve compliance, cannot be reasonably estimated at this time.

Clean Water Act
The Clean Water Act and associated regulations enacted by the EPA form a comprehensive program to restore and preserve water quality. Like the Clean Air Act, states are required to establish regulations and programs to address all requirements of the Clean Water Act, and have the flexibility to enact more stringent requirements. All of Great Plains Energy's and KCP&L's generating facilities, and certain of their other facilities, are subject to the Clean Water Act.

In May 2014, the EPA finalized regulations pursuant to Section 316(b) of the Clean Water Act regarding cooling water intake structures pursuant to a court approved settlement. KCP&L generation facilities with cooling water intake structures are subject to the best technology available standards based on studies completed to comply with such standards. The rule provides flexibility to work with the states to develop the best technology available to minimize aquatic species impacted by being pinned against intake screens (impingement) or drawn into cooling water systems (entrainment). Estimated costs to comply with Section 316(b) of the Clean Water Act are included in the estimated capital expenditures table above.

KCP&L holds a permit from the Missouri Department of Natural Resources (MDNR) covering water discharge from its Hawthorn Station. The permit authorizes KCP&L to, among other things, withdraw water from the Missouri River for cooling purposes and return the heated water to the Missouri River. KCP&L has applied for a renewal of this permit and the EPA has submitted an interim objection letter regarding the allowable amount of heat that can be contained in the returned water. Until this matter is resolved, KCP&L continues to operate under its current permit. Future water permit renewals at KCP&L's Iatan Station and at GMO's Sibley and Lake Road Stations could also be impacted by the allowable amount of heat that can be contained in the returned water. Great Plains Energy and KCP&L cannot predict the outcome of these matters; however, while less significant outcomes are possible, these matters may require a reduction in generation, installation of cooling towers or other technology to cool the water, or both, any of which could have a significant impact on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

In September 2015, the EPA finalized a revision of the technology-based effluent limitations guidelines and standards regulation to make the existing controls on discharges from steam electric power plants more stringent. The final rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. The new requirements for existing power plants would be phased in between 2018 and 2023. The final rule establishes new or additional requirements for wastewaters associated with the following processes and byproducts at certain KCP&L and GMO stations: flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and combustion residual leachate from landfills and surface impoundments. Estimated capital costs to comply with the final rule are included in the estimated capital expenditures table above.

Solid Waste
Solid and hazardous waste generation, storage, transportation, treatment and disposal are regulated at the federal and state levels under various laws and regulations. In December 2014, the EPA finalized regulations to regulate CCRs under the Resource Conservation and Recovery Act (RCRA) subtitle D to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The Companies use coal in

generating electricity and dispose of the CCRs in both on-site facilities and facilities owned by third parties. The rule requires periodic assessments; groundwater monitoring; location restrictions; design and operating requirements; recordkeeping and notifications; and closure, among other requirements, for CCR units. The rule was promulgated in the Federal Register on April 17, 2015, and became effective six months after promulgation with various obligations effective at specified times within the rule. Estimated capital costs to comply with the CCR rule are included in the estimated capital expenditures table above. See Note 7 for information regarding an increase in Great Plains Energy's and KCP&L's AROs as a result of the CCR rule.

Remediation

Certain federal and state laws, including the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), hold current and previous owners or operators of contaminated facilities and persons who arranged for the disposal or treatment of hazardous substances liable for the cost of investigation and cleanup. CERCLA and other laws also authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. GMO is named as a potentially responsible party at a disposal site for polychlorinated biphenyl (PCB) contamination, and retains some environmental liability for several operations and investments it no longer owns. In addition, GMO also owns, or has acquired liabilities from companies that once owned or operated, former manufactured gas plant (MGP) sites, which are subject to the supervision of the EPA and various state environmental agencies.

At December 31, 2015, and 2014, KCP&L had $0.3 million accrued for environmental remediation expenses, which covers ground water monitoring at a former MGP site. The amount accrued was established on an undiscounted basis and KCP&L does not currently have an estimated time frame over which the accrued amount may be paid.

In addition to the $0.3 million accrual above, at December 31, 2015, and 2014, Great Plains Energy had $1.4 million accrued for the future investigation and remediation of certain additional GMO identified MGP sites and retained liabilities. This estimate was based upon review of the potential costs associated with conducting investigative and remedial actions at identified sites, as well as the likelihood of whether such actions will be necessary. This estimate could change materially after further investigation, and could also be affected by the actions of environmental agencies and the financial viability of other potentially responsible parties; however, given the uncertainty of these items the possible loss or range of loss in excess of the amount accrued is not estimable.

GMO has pursued recovery of remediation costs from insurance carriers and other potentially responsible parties. As a result of a settlement with an insurance carrier, approximately $1.4 million in insurance proceeds less an annual deductible is available to GMO to recover qualified MGP remediation expenses. GMO would seek recovery of additional remediation costs and expenses through rate increases; however, there can be no assurance that such rate increases would be granted.

Contractual Commitments

Great Plains Energy's and KCP&L's expenses related to lease commitments are detailed in the following table.

	2015	2014	2013
	(millions)		
Great Plains Energy	$ 16.8	$ 16.0	$ 18.5
KCP&L	15.0	14.0	16.0

Great Plains Energy's and KCP&L's contractual commitments at December 31, 2015, excluding pensions and long-term debt, are detailed in the following tables.

Great Plains Energy

	2016	2017	2018	2019	2020	After 2020	Total
Lease commitments				(millions)			
Operating lease	$ 12.3	$ 10.6	$ 9.7	$ 9.9	$ 9.6	$ 121.5	$ 173.6
Capital lease	0.4	0.4	0.4	0.4	0.4	3.5	5.5
Purchase commitments							
Fuel	311.4	283.2	212.7	196.9	190.3	52.5	1,247.0
Power	47.3	47.3	47.3	47.3	47.3	509.5	746.0
Capacity	1.2	—	—	—	—	—	1.2
Non-regulated natural gas transportation	3.5	0.9	—	—	—	—	4.4
Other	74.7	11.0	27.8	40.0	5.2	41.1	199.8
Total contractual commitments	$ 450.8	$ 353.4	$ 297.9	$ 294.5	$ 252.8	$ 728.1	$ 2,377.5

KCP&L

	2016	2017	2018	2019	2020	After 2020	Total
Lease commitments				(millions)			
Operating lease	$ 11.9	$ 10.6	$ 9.7	$ 9.9	$ 9.6	$ 121.5	$ 173.2
Capital lease	0.2	0.2	0.2	0.2	0.2	1.8	2.8
Purchase commitments							
Fuel	264.7	243.2	178.2	182.3	175.8	52.5	1,096.7
Power	34.8	34.8	34.8	34.8	34.8	359.8	533.8
Capacity	1.2	—	—	—	—	—	1.2
Other	55.6	10.2	26.9	36.3	4.3	34.5	167.8
Total contractual commitments	$ 368.4	$ 299.0	$ 249.8	$ 263.5	$ 224.7	$ 570.1	$ 1,975.5

Great Plains Energy's and KCP&L's lease commitments end in 2048. Operating lease commitments include rail cars to serve jointly-owned generating units where KCP&L is the managing partner. Of the amounts included in the table above, KCP&L will be reimbursed by the other owners for approximately $1.5 million in 2016, $0.9 million in 2017 and approximately $0.4 million per year from 2018 to 2025, for a total of $6.0 million.

Fuel commitments consist of commitments for nuclear fuel, coal and coal transportation. Power commitments consist of commitments for renewable energy under power purchase agreements. KCP&L and GMO purchase capacity from other utilities and nonutility suppliers. Purchasing capacity provides the option to purchase energy if needed or when market prices are favorable. KCP&L has capacity sales agreements not included above that total $6.0 million, $1.9 million, $2.1 million, $1.9 million and $2.0 million per year from 2016 to 2020, respectively. Non-regulated natural gas transportation consists of MPS Merchant's commitments. Other represents individual commitments entered into in the ordinary course of business.

15. LEGAL PROCEEDINGS

GMO Western Energy Crisis

In response to complaints of excessive prices in the California energy markets, FERC issued an order in July 2001 requiring net sellers of power in the California markets from October 2, 2000, through June 20, 2001, at prices above a FERC-determined competitive market clearing price, to make refunds to net purchasers of power in the California market during that time period. Because MPS Merchant was a net purchaser of power during the refund period, it has received approximately $8 million in refunds through settlements with certain sellers of power. MPS Merchant estimates that it is entitled to approximately $12 million in additional refunds under the standards FERC

has used in this case once a comprehensive resettlement of those markets occurs, as required by FERC. FERC has stated that interest will be applied to the refunds but the amount of interest has not yet been determined.

In December 2001, various parties appealed FERC orders to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) seeking review of a number of issues, including expansion of the refund period to include periods prior to October 2, 2000 (the Summer Period). MPS Merchant was a net seller of power during the Summer Period. On August 2, 2006, the Ninth Circuit issued an order finding, among other things, that FERC erred in failing to consider certain legal issues regarding whether it has authority to order refunds for violation of FERC-approved tariffs during the Summer Period. The court remanded the matter to FERC for further consideration.

In November 2014 FERC issued an order finding that MPS Merchant engaged in tariff violations during the Summer Period and ordering refunds in the form of disgorgement of certain revenues. MPS Merchant (and other parties) filed a request for rehearing challenging FERC's findings of tariff violations and the remedy imposed in the November 2014 order. Additionally, several parties representing California utilities and governmental agencies filed a request for clarification or rehearing focusing on the remedy.

In November 2015, FERC issued an order on rehearing, confirming its findings of violation and expanding the remedy from its November 2014 order to cover additional MPS Merchant sales in the California markets. MPS Merchant filed another request for rehearing, challenging the expanded remedy, and also filed a petition for review of the November 2014 and November 2015 orders with the Ninth Circuit.

In February 2016, FERC issued another order on rehearing/clarification that requires MPS Merchant to refund, in the form of disgorgement, all revenues in excess of the FERC-determined competitive market clearing price for all sales in the California markets during the Summer Period that occurred in any hour in which any remaining respondent in the proceeding was found to have committed a tariff violation. That order is subject to further rehearing and judicial review. Under FERC's orders, MPS Merchant may be able to offset its costs of selling power against any remedy ultimately imposed to ensure that it does not under-recover its actual costs.

Due to the uncertainties remaining in the case, the loss or range of loss cannot be reasonably estimated.

16. GUARANTEES

In the ordinary course of business, Great Plains Energy and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees and letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiary's intended business purposes. The majority of these agreements guarantee the Company's own future performance, so a liability for the fair value of the obligation is not recorded.

At December 31, 2015, Great Plains Energy has provided $138.4 million of credit support for GMO as follows:

- Great Plains Energy direct guarantees to GMO counterparties totaling $40.7 million, which expire in 2016 and
- Great Plains Energy guarantee of GMO long-term debt totaling $97.7 million, which includes debt with maturity dates ranging from 2016 to 2023.

Great Plains Energy has also guaranteed GMO's commercial paper program. At December 31, 2015, GMO had $43.7 million commercial paper outstanding.

17. RELATED PARTY TRANSACTIONS AND RELATIONSHIPS

KCP&L employees manage GMO's business and operate its facilities at cost, including GMO's 18% ownership interest in KCP&L's Iatan Nos. 1 and 2. The operating expenses and capital costs billed from KCP&L to GMO were $183.6 million for 2015, $173.9 million for 2014 and $223.6 million for 2013. Additionally, KCP&L and

GMO engage in wholesale electricity transactions with each other. KCP&L's net wholesale sales to GMO were $0.2 million, $12.7 million and $25.6 million in 2015, 2014 and 2013, respectively.

KCP&L and GMO are also authorized to participate in the Great Plains Energy money pool, an internal financing arrangement in which funds may be lent on a short-term basis to KCP&L and GMO from Great Plains Energy and between KCP&L and GMO. At December 31, 2014, KCP&L had a money pool payable to GMO of $12.6 million.

The following table summarizes KCP&L's related party net receivables.

	December 31	
	2015	2014
	(millions)	
Net receivable from GMO	$ 50.0	$ 38.2
Net receivable from Great Plains Energy	15.8	18.0

18. DERIVATIVE INSTRUMENTS

Great Plains Energy and KCP&L are exposed to a variety of market risks including interest rates and commodity prices. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on Great Plains Energy's and KCP&L's operating results. Great Plains Energy's and KCP&L's interest rate risk management activities have included using derivative instruments to hedge against future interest rate fluctuations on anticipated debt issuances. Commodity risk management activities, including the use of certain derivative instruments, are subject to the management, direction and control of an internal commodity risk committee. Management maintains commodity price risk management strategies that use derivative instruments to reduce the effects of fluctuations in wholesale sales, fuel and purchased power expense caused by commodity price volatility.

Counterparties to commodity derivatives expose Great Plains Energy and KCP&L to credit loss in the event of nonperformance. This credit loss is limited to the cost of replacing these contracts at current market rates. Derivative instruments, excluding those instruments that qualify for the NPNS election, which are accounted for by accrual accounting, are recorded on the balance sheet at fair value as an asset or liability. Changes in the fair value of derivative instruments are recorded to a regulatory asset or liability consistent with KCC and MPSC regulatory orders.

Great Plains Energy and KCP&L have posted collateral, in the ordinary course of business, for the aggregate fair value of all derivative instruments with credit risk-related contingent features that are in a liability position. At December 31, 2015, Great Plains Energy and KCP&L have posted collateral in excess of the aggregate fair value of their derivative instruments; therefore, if the credit risk-related contingent features underlying these agreements were triggered, Great Plains Energy and KCP&L would not be required to post additional collateral to their counterparties. For derivative contracts with counterparties under master netting arrangements, Great Plains Energy and KCP&L can net receivables and payables with each respective counterparty.

Commodity Risk Management

KCP&L's risk management policy uses derivative instruments to mitigate exposure to market price fluctuations for wholesale power. KCP&L has designated these financial contracts as economic hedges (non-hedging derivatives). The fair values of these instruments are recorded as derivative assets or liabilities with an offsetting entry recorded to a regulatory asset or liability. The settlement costs are included in KCP&L's fuel recovery mechanisms. A regulatory asset or liability is recorded to reflect the change in the timing of recognition authorized by KCC and MPSC. Recovery of actual costs will not impact earnings, but will impact cash flows due to the timing of the recovery mechanism.

KCP&L and GMO have Transmission Congestion Rights (TCRs) that they utilize to hedge against congestion costs and protect load prices in the Southwest Power Pool, Inc. (SPP) Integrated Marketplace. These financial contracts have been designated as economic hedges (non-hedging derivatives). The fair values of these instruments are

recorded as derivative assets or liabilities with an offsetting entry recorded to a regulatory asset or liability. The settlement costs are included in KCP&L's and GMO's fuel recovery mechanisms. A regulatory asset or liability is recorded to reflect the change in the timing of recognition authorized by KCC and MPSC. Recovery of actual costs will not impact earnings, but will impact cash flows due to the timing of the recovery mechanism.

GMO's risk management policy uses derivative instruments to mitigate price exposure to natural gas price volatility in the market. At December 31, 2015, GMO had financial contracts in place to hedge approximately 66%, 18% and 8% of the expected on-peak natural gas generation and natural gas equivalent purchased power price exposure for 2016, 2017 and 2018, respectively. The fair value of the portfolio will settle against actual purchases of natural gas and purchased power. GMO has designated its natural gas hedges as economic hedges (non-hedging derivatives). In connection with GMO's 2005 Missouri electric rate case, it was agreed that the settlement costs of these contracts would be recognized in fuel expense. The settlement cost is included in GMO's fuel recovery mechanism. A regulatory asset or liability is recorded to reflect the change in the timing of recognition authorized by the MPSC. Recovery of actual costs will not impact earnings, but will impact cash flows due to the timing of the recovery mechanism.

MPS Merchant, which has certain long-term natural gas contracts remaining from its former non-regulated trading operations, manages the daily delivery of its remaining contractual commitments with economic hedges (non-hedging derivatives) to reduce its exposure to changes in market prices. Within the trading portfolio, MPS Merchant takes certain positions to hedge physical sale or purchase contracts. MPS Merchant records the fair value of physical trading energy contracts as derivative assets or liabilities with an offsetting entry to the consolidated statements of comprehensive income.

The gross notional contract amount and recorded fair values of open positions for derivative instruments are summarized in the following table. The fair values of these derivatives are recorded on the consolidated balance sheets. The fair values below are gross values before netting agreements and netting of cash collateral.

	December 31			
	2015		2014	
	Notional Contract Amount	Fair Value	Notional Contract Amount	Fair Value
Great Plains Energy	(millions)			
Non-hedging derivatives				
Futures contracts	$ 26.6	$ (5.7)	$ 14.9	$ (2.4)
Forward contracts	15.6	3.1	29.7	4.1
Transmission congestion rights	5.6	(0.5)	28.3	2.6
Option contracts	—	—	1.7	0.1
KCP&L				
Non-hedging derivatives				
Futures contracts	$ 0.9	$ (0.1)	$ —	$ —
Transmission congestion rights	4.1	(0.4)	23.6	3.1

The fair values of Great Plains Energy's and KCP&L's open derivative positions and balance sheet classification are summarized in the following tables. The fair values below are gross values before netting agreements and netting of cash collateral.

Great Plains Energy

	Balance Sheet Classification	Asset Derivatives Fair Value	Liability Derivatives Fair Value
December 31, 2015			
Derivatives Not Designated as Hedging Instruments		(millions)	
Commodity contracts	Other	$ 3.3	$ 6.4
December 31, 2014			
Derivatives Not Designated as Hedging Instruments			
Commodity contracts	Other	$ 8.6	$ 4.2

KCP&L

	Balance Sheet Classification	Asset Derivatives Fair Value	Liability Derivatives Fair Value
December 31, 2015			
Derivatives Not Designated as Hedging Instruments		(millions)	
Commodity contracts	Other	$ 0.2	$ 0.7
December 31, 2014			
Derivatives Not Designated as Hedging Instruments			
Commodity contracts	Other	$ 4.0	$ 0.9

The following tables provide information regarding Great Plains Energy's and KCP&L's offsetting of derivative assets and liabilities.

Great Plains Energy

				Gross Amounts Not Offset in the Statement of Financial Position		
Description	**Gross Amounts Recognized**	**Gross Amounts Offset in the Statement of Financial Position**	**Net Amounts Presented in the Statement of Financial Position**	**Financial Instruments**	**Cash Collateral**	**Net Amount**
December 31, 2015			(millions)			
Derivative assets	$ 3.3	$ (0.2)	$ 3.1	$ —	$ —	$ 3.1
Derivative liabilities	6.4	(5.9)	0.5	—	—	0.5
December 31, 2014						
Derivative assets	$ 8.6	$ (1.2)	$ 7.4	$ —	$ —	$ 7.4
Derivative liabilities	4.2	(3.5)	0.7	—	—	0.7

KCP&L

Description	Gross Amounts Recognized	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral	Net Amount
December 31, 2015			(millions)			
Derivative assets	$ 0.2	$ (0.2)	$ —	$ —	$ —	$ —
Derivative liabilities	0.7	(0.3)	0.4	—	—	0.4
December 31, 2014						
Derivative assets	$ 4.0	$ (0.9)	$ 3.1	$ —	$ —	$ 3.1
Derivative liabilities	0.9	(0.9)	—	—	—	—

At December 31, 2015, and 2014, Great Plains Energy offset $5.7 million and $2.3 million, respectively, of cash collateral posted with counterparties against net derivative positions.

See Note 20 for information regarding amounts reclassified out of accumulated other comprehensive loss for Great Plains Energy and KCP&L.

Great Plains Energy's accumulated OCI at December 31, 2015, includes $9.2 million that is expected to be reclassified to expenses over the next twelve months. KCP&L's accumulated OCI at December 31, 2015, includes $8.8 million that is expected to be reclassified to expenses over the next twelve months.

The following tables summarize the amounts of gain (loss) recognized for the change in fair value of commodity contract derivatives not designated as hedging instruments for Great Plains Energy and KCP&L.

Great Plains Energy

Derivatives Not Designated as Hedging Instruments	2015	2014	2013
Location of Gain (Loss)		(millions)	
Electric revenues	$ (8.2)	$ (14.2)	$ —
Fuel	(2.5)	1.5	(1.1)
Purchased power	(1.5)	(4.9)	—
Regulatory asset	(6.8)	(2.7)	—
Regulatory liability	—	—	0.2
Total	$ (19.0)	$ (20.3)	$ (0.9)

KCP&L

Derivatives Not Designated as Hedging Instruments	2015	2014	2013
Location of Gain (Loss)		(millions)	
Electric revenues	$ (8.2)	$ (14.2)	$ —
Fuel	1.5	1.1	0.8
Regulatory asset	(0.5)	(0.2)	—
Total	$ (7.2)	$ (13.3)	$ 0.8

19. FAIR VALUE MEASUREMENTS

GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad categories, giving the highest priority to quoted prices in active markets for identical assets or liabilities and lowest priority to unobservable inputs. A definition of the various levels, as well as discussion of the various measurements within the levels, is as follows:

Level 1 – Unadjusted quoted prices for identical assets or liabilities in active markets that Great Plains Energy and KCP&L have access to at the measurement date.

Level 2 – Market-based inputs for assets or liabilities that are observable (either directly or indirectly) or inputs that are not observable but are corroborated by market data.

Level 3 – Unobservable inputs, reflecting Great Plains Energy's and KCP&L's own assumptions about the assumptions market participants would use in pricing the asset or liability.

Great Plains Energy and KCP&L record cash and cash equivalents and short-term borrowings on the balance sheet at cost, which approximates fair value due to the short-term nature of these instruments.

Great Plains Energy and KCP&L record long-term debt on the balance sheet at amortized cost. The fair value of long-term debt is measured as a Level 2 liability and is based on quoted market prices, with the incremental borrowing rate for similar debt used to determine fair value if quoted market prices are not available. At December 31, 2015, the book value and fair value of Great Plains Energy's long-term debt, including current maturities, were $3.7 billion and $4.0 billion, respectively. At December 31, 2014, the book value and fair value of Great Plains Energy's long-term debt, including current maturities, were $3.5 billion and $3.8 billion, respectively. At December 31, 2015, the book value and fair value of KCP&L's long-term debt, including current maturities, were $2.6 billion and $2.8 billion, respectively. At December 31, 2014, the book value and fair value of KCP&L's long-term debt, including current maturities, were $2.3 billion and $2.6 billion, respectively.

The following tables include Great Plains Energy's and KCP&L's balances of financial assets and liabilities measured at fair value on a recurring basis. The fair values below are gross values before netting arrangements and netting of cash collateral.

Description	December 31 2015	Level 1	Level 2	Level 3
KCP&L		(millions)		
Assets				
Nuclear decommissioning trust [a]				
Equity securities	$ 135.4	$ 135.4	$ —	$ —
Debt securities				
U.S. Treasury	26.4	26.4	—	—
U.S. Agency	1.8	—	1.8	—
State and local obligations	4.0	—	4.0	—
Corporate bonds	29.2	—	29.2	—
Foreign governments	0.3	—	0.3	—
Cash equivalents	3.6	3.6	—	—
Total nuclear decommissioning trust	200.7	165.4	35.3	—
Self-insured health plan trust [b]				
Equity securities	1.1	1.1	—	—
Debt securities	7.3	—	7.3	—
Cash and cash equivalents	5.2	5.2	—	—
Total self-insured health plan trust	13.6	6.3	7.3	—
Derivative instruments [c]	0.2	—	—	0.2
Total	$ 214.5	$ 171.7	$ 42.6	$ 0.2
Liabilities				
Derivative instruments [c]	0.7	0.1	—	0.6
Total	$ 0.7	$ 0.1	$ —	$ 0.6
Other Great Plains Energy				
Assets				
Derivative instruments [c]	$ 3.1	$ —	$ 2.7	$ 0.4
SERP rabbi trusts [d]				
Equity securities	0.1	0.1	—	—
Total	$ 3.2	$ 0.1	$ 2.7	$ 0.4
Liabilities				
Derivative instruments [c]	5.7	5.6	—	0.1
Total	$ 5.7	$ 5.6	$ —	$ 0.1
Great Plains Energy				
Assets				
Nuclear decommissioning trust [a]	$ 200.7	$ 165.4	$ 35.3	$ —
Self-insured health plan trust [b]	13.6	6.3	7.3	—
Derivative instruments [c]	3.3	—	2.7	0.6
SERP rabbi trusts [d]	0.1	0.1	—	—
Total	$ 217.7	$ 171.8	$ 45.3	$ 0.6
Liabilities				
Derivative instruments [c]	6.4	5.7	—	0.7
Total	$ 6.4	$ 5.7	$ —	$ 0.7

Description	December 31 2014	Level 1	Level 2	Level 3
KCP&L		(millions)		
Assets				
Nuclear decommissioning trust [(a)]				
Equity securities	$ 137.1	$ 137.1	$ —	$ —
Debt securities				
U.S. Treasury	22.9	22.9	—	—
U.S. Agency	3.5	—	3.5	—
State and local obligations	4.1	—	4.1	—
Corporate bonds	28.1	—	28.1	—
Foreign governments	0.5	—	0.5	—
Cash equivalents	2.3	2.3	—	—
Other	0.5	—	0.5	—
Total nuclear decommissioning trust	199.0	162.3	36.7	—
Self-insured health plan trust [(b)]				
Equity securities	1.3	1.3	—	—
Debt securities	7.6	—	7.6	—
Cash and cash equivalents	6.2	6.2	—	—
Total self-insured health plan trust	15.1	7.5	7.6	—
Derivative instruments [(c)]	4.0	—	—	4.0
Total	$ 218.1	$ 169.8	$ 44.3	$ 4.0
Liabilities				
Derivative instruments [(c)]	0.9	—	—	0.9
Total	$ 0.9	$ —	$ —	$ 0.9
Other Great Plains Energy				
Assets				
Derivative instruments [(c)]	$ 4.6	$ —	$ 3.4	$ 1.2
SERP rabbi trusts [(d)]				
Equity securities	0.1	0.1	—	—
Total	$ 4.7	$ 0.1	$ 3.4	$ 1.2
Liabilities				
Derivative instruments [(c)]	3.3	2.4	0.1	0.8
Total	$ 3.3	$ 2.4	$ 0.1	$ 0.8
Great Plains Energy				
Assets				
Nuclear decommissioning trust [(a)]	$ 199.0	$ 162.3	$ 36.7	$ —
Self-insured health plan trust [(b)]	15.1	7.5	7.6	—
Derivative instruments [(c)]	8.6	—	3.4	5.2
SERP rabbi trusts [(d)]	0.1	0.1	—	—
Total	$ 222.8	$ 169.9	$ 47.7	$ 5.2
Liabilities				
Derivative instruments [(c)]	4.2	2.4	0.1	1.7
Total	$ 4.2	$ 2.4	$ 0.1	$ 1.7

(a) Fair value is based on quoted market prices of the investments held by the fund and/or valuation models.

(b) Fair value is based on quoted market prices of the investments held by the trust. Debt securities classified as Level 2 are comprised of corporate bonds, U.S. Agency, state and local obligations, and other asset-backed securities.

(c) The fair value of derivative instruments is estimated using market quotes, over-the-counter forward price and volatility curves and correlations among fuel prices, net of estimated credit risk. Derivative instruments classified as Level 1 represent exchange traded derivative instruments. Derivative instruments classified as Level 2 represent non-exchange traded derivative instruments traded in over-the-counter markets. Derivative instruments classified as Level 3 represent non-exchange traded derivatives traded in over-the-counter markets for which observable market data is not available to corroborate the valuation inputs and TCRs valued at the most recent auction price in the SPP Integrated Marketplace.

(d) At December 31, 2015 and 2014, the SERP rabbi trusts also included $16.6 million and $17.8 million, respectively, of fixed income funds valued at NAV per share (or its equivalent) that are not categorized in the fair value hierarchy. The fixed income fund invests primarily in intermediate and long-term debt securities, can be redeemed immediately and is not subject to any restrictions on redemptions.

The following tables reconcile the beginning and ending balances for all Level 3 assets and liabilities measured at fair value on a recurring basis.

Great Plains Energy

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Derivative Instruments	
	2015	**2014**
	(millions)	
Net asset at January 1	$ 3.5	$ 3.3
Total realized/unrealized gains (losses):		
included in electric revenue	(8.2)	(14.2)
included in purchased power expense	(1.5)	(4.9)
included in non-operating income	8.6	14.6
included in regulatory asset	(0.5)	(0.1)
Purchases	—	16.0
Settlements	(2.0)	(11.2)
Net asset (liability) at December 31	$ (0.1)	$ 3.5
Total unrealized losses relating to assets and liabilities still on the consolidated balance sheet at December 31:		
included in electric revenue	$ —	$ (0.2)
included in non-operating income	(0.2)	(0.3)
included in regulatory asset	(0.5)	(0.1)

KCP&L

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Derivative Instruments	
	2015	**2014**
	(millions)	
Net asset at January 1	$ 3.1	$ 1.1
Total realized/unrealized gains (losses):		
included in electric revenue	(8.2)	(14.2)
included in regulatory asset	(0.4)	(0.2)
Purchases	(0.8)	13.7
Settlements	5.9	2.7
Net asset (liability) at December 31	$ (0.4)	$ 3.1
Total unrealized losses relating to assets and liabilities still on the consolidated balance sheet at December 31:		
included in electric revenue	$ —	$ (0.2)
included in regulatory asset	(0.4)	(0.2)

20. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following tables reflect the change in the balances of each component of accumulated other comprehensive loss for Great Plains Energy and KCP&L.

Great Plains Energy

	Gains and Losses on Cash Flow Hedges[a]	Defined Benefit Pension Items[a]	Total[a]
	(millions)		
2015			
Beginning balance January 1	$ (15.8)	$ (2.9)	$ (18.7)
Other comprehensive income before reclassifications	—	0.6	0.6
Amounts reclassified from accumulated other comprehensive loss	5.7	0.4	6.1
Net current period other comprehensive income	5.7	1.0	6.7
Ending balance December 31	$ (10.1)	$ (1.9)	$ (12.0)
2014			
Beginning balance January 1	$ (23.8)	$ (1.5)	$ (25.3)
Other comprehensive loss before reclassifications	—	(1.8)	(1.8)
Amounts reclassified from accumulated other comprehensive loss	8.0	0.4	8.4
Net current period other comprehensive income	8.0	(1.4)	6.6
Ending balance December 31	$ (15.8)	$ (2.9)	$ (18.7)

[a] Net of tax

KCP&L

	Gains and Losses on Cash Flow Hedges[a]
	(millions)
2015	
Beginning balance January 1	$ (14.9)
Amounts reclassified from accumulated other comprehensive loss	5.3
Net current period other comprehensive income	5.3
Ending balance December 31	$ (9.6)
2014	
Beginning balance January 1	$ (20.2)
Amounts reclassified from accumulated other comprehensive loss	5.3
Net current period other comprehensive income	5.3
Ending balance December 31	$ (14.9)

[a] Net of tax

The following tables reflect the effect on certain line items of net income from amounts reclassified out of each component of accumulated other comprehensive loss for Great Plains Energy and KCP&L.

Great Plains Energy

Details about Accumulated Other Comprehensive Loss Components	Amount Reclassified from Accumulated Other Comprehensive Loss 2015	2014	Affected Line Item in the Income Statement
	(millions)		
Gains and (losses) on cash flow hedges (effective portion)			
Interest rate contracts	$ (9.2)	$ (13.1)	Interest charges
	(9.2)	(13.1)	Income before income tax expense and income (loss) from equity investments
	3.5	5.1	Income tax benefit
	$ (5.7)	$ (8.0)	Net income
Amortization of defined benefit pension items			
Net losses included in net periodic benefit costs	$ (0.7)	$ (0.6)	Utility operating and maintenance expenses
	(0.7)	(0.6)	Income before income tax expense and income (loss) from equity investments
	0.3	0.2	Income tax benefit
	$ (0.4)	$ (0.4)	Net income
Total reclassifications, net of tax	$ (6.1)	$ (8.4)	Net income

KCP&L

Details about Accumulated Other Comprehensive Loss Components	Amount Reclassified from Accumulated Other Comprehensive Loss 2015	2014	Affected Line Item in the Income Statement
	(millions)		
Gains and (losses) on cash flow hedges (effective portion)			
Interest rate contracts	$ (8.7)	$ (8.7)	Interest charges
	(8.7)	(8.7)	Income before income tax expense
	3.4	3.4	Income tax benefit
Total reclassifications, net of tax	$ (5.3)	$ (5.3)	Net income

21. TAXES

Components of income tax expense are detailed in the following tables.

Great Plains Energy	2015	2014	2013
Current income taxes		(millions)	
Federal	$ (0.2)	$ 0.4	$ 0.3
State	(1.1)	(0.1)	(3.0)
Total	(1.3)	0.3	(2.7)
Deferred income taxes			
Federal	96.9	104.2	109.1
State	28.0	21.6	24.9
Total	124.9	125.8	134.0
Noncurrent income taxes			
Federal	—	(2.4)	—
State	—	(0.5)	(0.3)
Foreign	—	(6.1)	(0.4)
Total	—	(9.0)	(0.7)
Investment tax credit			
Deferral	0.5	—	0.3
Amortization	(1.4)	(1.4)	(1.7)
Total	(0.9)	(1.4)	(1.4)
Income tax expense	$ 122.7	$ 115.7	$ 129.2

KCP&L	2015	2014	2013
Current income taxes		(millions)	
Federal	$ (18.7)	$ (9.4)	$ (0.5)
State	(3.4)	(2.3)	(0.5)
Total	(22.1)	(11.7)	(1.0)
Deferred income taxes			
Federal	81.9	72.6	75.8
State	17.5	15.8	16.3
Total	99.4	88.4	92.1
Noncurrent income taxes			
Federal	—	—	(9.0)
State	—	—	(1.5)
Total	—	—	(10.5)
Investment tax credit			
Deferral	0.5	—	0.3
Amortization	(1.0)	(1.0)	(1.1)
Total	(0.5)	(1.0)	(0.8)
Income tax expense	$ 76.8	$ 75.7	$ 79.8

Effective Income Tax Rates

Effective income tax rates reflected in the financial statements and the reasons for their differences from the statutory federal rates are detailed in the following tables.

Great Plains Energy	**2015**	**2014**	**2013**
Federal statutory income tax rate	35.0%	35.0%	35.0%
Differences between book and tax depreciation not normalized	—	(0.7)	(0.3)
Amortization of investment tax credits	(0.4)	(0.4)	(0.4)
Federal income tax credits	(4.1)	(3.8)	(3.5)
State income taxes	4.0	3.8	3.8
Changes in uncertain tax positions, net	—	(1.7)	(0.2)
Valuation allowance	1.5	—	—
Other	0.5	0.1	(0.4)
Effective income tax rate	36.5%	32.3%	34.0%

KCP&L	**2015**	**2014**	**2013**
Federal statutory income tax rate	35.0%	35.0%	35.0%
Differences between book and tax depreciation not normalized	—	(0.9)	(0.8)
Amortization of investment tax credits	(0.5)	(0.4)	(0.4)
Federal income tax credits	(5.6)	(5.6)	(5.3)
State income taxes	4.0	3.7	3.7
Valuation allowance	0.3	—	—
Other	0.3	—	(0.1)
Effective income tax rate	33.5%	31.8%	32.1%

Deferred Income Taxes

The tax effects of major temporary differences resulting in deferred income tax assets (liabilities) in the consolidated balance sheets are in the following tables:

	Great Plains Energy		KCP&L	
December 31	**2015**	**2014**	**2015**	**2014**
Current deferred income tax asset	(millions)			
Net operating loss carryforward	$ —	$ 62.2	$ —	$ —
Other	—	17.1	—	5.0
Current deferred income tax asset before valuation allowance	—	79.3	—	5.0
Valuation allowance	—	(1.2)	—	—
Current deferred income tax asset[a]	—	78.1	—	5.0
Noncurrent deferred income taxes				
Plant related	(1,967.0)	(1,648.2)	(1,398.9)	(1,167.3)
Income taxes on future regulatory recoveries	(151.3)	(133.4)	(125.0)	(107.1)
Derivative instruments	20.5	26.5	14.0	18.9
Pension and post-retirement benefits	(0.1)	(14.0)	27.4	12.5
SO_2 emission allowance sales	25.7	27.1	25.7	27.3
Tax credit carryforwards	256.8	242.7	166.6	153.2
Customer demand programs	(22.7)	(26.2)	(16.9)	(19.0)
Solar rebates	(31.9)	(33.2)	(13.1)	(11.3)
Net operating loss carryforward	734.9	524.7	204.2	98.5
Other	(3.8)	(40.3)	(15.9)	(22.6)
Net noncurrent deferred income tax liability before valuation allowance	(1,138.9)	(1,074.3)	(1,131.9)	(1,016.9)
Valuation allowance	(19.9)	(15.4)	(0.7)	—
Net noncurrent deferred income tax liability	(1,158.8)	(1,089.7)	(1,132.6)	(1,016.9)
Net deferred income tax liability	$(1,158.8)	$(1,011.6)	$(1,132.6)	$(1,011.9)

[a] Reflects adoption of ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes*. See Note 1 to the consolidated financial statements under the heading New Accounting Standards for additional information.

	Great Plains Energy		KCP&L	
December 31	**2015**	**2014**	**2015**	**2014**
	(millions)			
Gross deferred income tax assets	$ 1,368.5	$ 1,227.0	$ 740.9	$ 624.8
Gross deferred income tax liabilities	(2,527.3)	(2,238.6)	(1,873.5)	(1,636.7)
Net deferred income tax liability	$(1,158.8)	$(1,011.6)	$(1,132.6)	$(1,011.9)

Tax Credit Carryforwards

At December 31, 2015 and 2014, Great Plains Energy had $169.2 million and $155.1 million, respectively, of federal general business income tax credit carryforwards. At December 31, 2015 and 2014, KCP&L had $166.6 million and $153.2 million, respectively, of federal general business income tax credit carryforwards. The carryforwards for both Great Plains Energy and KCP&L relate primarily to Advanced Coal Investment Tax Credits and Wind Production tax credits and expire in the years 2028 to 2035. Approximately $0.5 million of Great Plains Energy's credits are related to Low Income Housing credits that were acquired in the GMO acquisition. Due to federal limitations on the utilization of income tax attributes acquired in the GMO acquisition, management expects a portion of these credits to expire unutilized and has provided a valuation allowance against $0.4 million of the federal income tax benefit.

At December 31, 2015 and 2014, Great Plains Energy had $87.6 million of federal alternative minimum tax credit carryforwards, all of which was acquired in the GMO acquisition. These credits do not expire and can be used to reduce taxes paid in the future.

Net Operating Loss Carryforwards
At December 31, 2015 and 2014, Great Plains Energy had $656.1 million and $521.0 million, respectively, of tax benefits related to federal net operating loss (NOL) carryforwards. Approximately $313.2 million at December 31, 2015 and 2014 are tax benefits related to NOLs that were acquired in the GMO acquisition. The tax benefits for NOLs originating in 2003 are $30.1 million, $152.4 million originating in 2004, $74.1 million originating in 2005, $53.3 million originating in 2006, $1.3 million originating in 2007, $2.4 million originating in 2008, $36.5 million originating in 2009, $4.1 million originating in 2010 and $109.7 million originating in 2011, $2.5 million originating in 2012, $2.3 million originating in 2013, $86.3 million originating in 2014 and $101.1 million originating in 2015. The federal NOL carryforwards expire in years 2023 to 2035. The Company expects a portion of these NOLs to expire unutilized and has provided a valuation allowance against $0.9 million of federal tax benefits.

In addition, Great Plains Energy also had deferred tax benefits of $78.8 million and $65.9 million related to state NOLs as of December 31, 2015 and 2014, respectively. Of these amounts, approximately $39.2 million and $40.7 million at December 31, 2015 and 2014, respectively, were acquired in the GMO acquisition. Management does not expect to utilize $18.6 million of NOLs in state tax jurisdictions where the Company does not expect to operate in the future. Therefore, a valuation allowance has been provided against $18.6 million of state tax benefits.

Valuation Allowances
Great Plains Energy is required to assess the ultimate realization of deferred tax assets using a "more likely than not" assessment threshold. This assessment takes into consideration tax planning strategies within Great Plains Energy's control. As a result of this assessment, Great Plains Energy has established a partial valuation allowance for federal and state tax NOL carryforwards and tax credit carryforwards. During 2015, $3.3 million of tax expense was recorded in continuing operations primarily related to state NOL carryforwards that the Company expects to expire unutilized due to the extension of bonus depreciation through 2019.

Uncertain Tax Positions
At December 31, 2015 and 2014, Great Plains Energy had $2.3 million and $2.6 million, respectively, of liabilities related to unrecognized tax benefits. Of these amounts, $0.3 million at December 31, 2015 and 2014, respectively, is expected to impact the effective tax rate if recognized.

At December 31, 2013, Great Plains Energy had $9.8 million of liabilities related to unrecognized tax benefits of which $6.5 million was expected to impact the effective tax rate if recognized. The $7.2 million decrease in unrecognized tax benefits is primarily due to a decrease of $6.1 million of unrecognized tax benefits were related to former GMO non-regulated operations.

The following table reflects activity for Great Plains Energy related to the liability for unrecognized tax benefits.

	Great Plains Energy		
	2015	2014	2013
	(millions)		
Beginning balance January 1	$ 2.6	$ 9.8	$ 21.4
Reductions for current year tax positions	(0.3)	(0.3)	(0.3)
Reductions for prior year tax positions	—	(6.9)	(10.5)
Statute expirations	—	—	(0.3)
Foreign currency translation adjustments	—	—	(0.5)
Ending balance December 31	$ 2.3	$ 2.6	$ 9.8

Great Plains Energy recognizes interest related to unrecognized tax benefits in interest expense and penalties in non-operating expenses. At December 31, 2015, 2014 and 2013, amounts accrued for interest related to unrecognized tax benefits for Great Plains Energy were none, none and $3.2 million, respectively. At December 31, 2015, 2014 and 2013, amounts accrued for penalties with respect to unrecognized tax benefits for Great Plains Energy were

none, none and $0.6 million, respectively. In 2015, 2014 and 2013, Great Plains Energy recognized a decrease of none, $3.2 million and $0.1 million, respectively, of interest expense related to unrecognized tax benefits.

The Company is unable to estimate the amount of unrecognized tax benefits for Great Plains Energy that may be recognized in the next twelve months.

Great Plains Energy files a consolidated federal income tax return as well as unitary and combined income tax returns in several state jurisdictions with Kansas and Missouri being the most significant. The Company also files separate company returns in Canada and certain other states.

22. SEGMENTS AND RELATED INFORMATION

Great Plains Energy has one reportable segment based on its method of internal reporting, which segregates reportable segments based on products and services, management responsibility and regulation. The one reportable business segment is electric utility, consisting of KCP&L, GMO's regulated utility operations and GMO Receivables Company. Other includes GMO activity other than its regulated utility operations, GPETHC and unallocated corporate charges. The summary of significant accounting policies applies to the reportable segment. Segment performance is evaluated based on net income.

The following tables reflect summarized financial information concerning Great Plains Energy's reportable segment.

2015	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,502.2	$ —	$ —	$ 2,502.2
Depreciation and amortization	(330.4)	—	—	(330.4)
Interest (charges) income	(190.9)	(40.5)	32.1	(199.3)
Income tax expense	(120.8)	(1.9)	—	(122.7)
Net income (loss)	223.8	(10.8)	—	213.0

2014	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,568.2	$ —	$ —	$ 2,568.2
Depreciation and amortization	(306.0)	—	—	(306.0)
Interest (charges) income	(183.0)	(41.2)	35.7	(188.5)
Income tax (expense) benefit	(125.6)	9.9	—	(115.7)
Net income (loss)	243.5	(0.7)	—	242.8

2013	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,446.3	$ —	$ —	$ 2,446.3
Depreciation and amortization	(289.7)	—	—	(289.7)
Interest (charges) income	(190.5)	(55.5)	47.6	(198.4)
Income tax (expense) benefit	(135.4)	6.2	—	(129.2)
Net income (loss)	257.1	(6.9)	—	250.2

	Electric Utility	Other	Eliminations	Great Plains Energy
2015	(millions)			
Assets	$11,045.5	$ (51.1)	$ (255.8)	$10,738.6
Capital expenditures	677.1	—	—	677.1
2014				
Assets	$10,727.7	$ 29.2	$ (303.5)	$10,453.4
Capital expenditures	773.7	—	—	773.7
2013				
Assets	$ 9,998.9	$ 101.1	$ (329.8)	$ 9,770.2
Capital expenditures	669.0	—	—	669.0

23. JOINTLY-OWNED ELECTRIC UTILITY PLANTS

Great Plains Energy's and KCP&L's share of jointly-owned electric utility plants at December 31, 2015, are detailed in the following tables.

Great Plains Energy

	Wolf Creek Unit	La Cygne Units	Iatan No. 1 Unit	Iatan No. 2 Unit	Iatan Common	Jeffrey Energy Center
	(millions, except MW amounts)					
Great Plains Energy's share	47%	50%	88%	73%	79%	8%
Utility plant in service	$ 1,809.1	$ 1,061.1	$ 667.7	$ 1,326.9	$ 470.0	$ 192.9
Accumulated depreciation	862.6	264.0	257.6	365.5	112.8	78.1
Nuclear fuel, net	68.3	—	—	—	—	—
Construction work in progress	74.3	38.4	3.3	20.5	35.2	2.9
2016 accredited capacity-MWs	549	699	627	641	NA	172

KCP&L

	Wolf Creek Unit	La Cygne Units	Iatan No. 1 Unit	Iatan No. 2 Unit	Iatan Common
	(millions, except MW amounts)				
KCP&L's share	47%	50%	70%	55%	61%
Utility plant in service	$ 1,809.1	$ 1,061.1	$ 531.7	$ 1,015.1	$ 385.1
Accumulated depreciation	862.6	264.0	209.0	331.0	101.4
Nuclear fuel, net	68.3	—	—	—	—
Construction work in progress	74.3	38.4	1.2	8.6	8.6
2016 accredited capacity-MWs	549	699	499	482	NA

Each owner must fund its own portion of the plant's operating expenses and capital expenditures. KCP&L's and GMO's share of direct expenses are included in the appropriate operating expense classifications in Great Plains Energy's and KCP&L's financial statements.

24. QUARTERLY OPERATING RESULTS (UNAUDITED)

Great Plains Energy	Quarter 1st	2nd	3rd	4th
2015	(millions, except per share amounts)			
Operating revenue	$ 549.1	$ 609.0	$ 781.4	$ 562.7
Operating income	70.1	119.9	256.7	83.4
Net income	18.9	44.4	126.8	22.9
Basic and diluted earnings per common share	0.12	0.28	0.82	0.15
2014				
Operating revenue	$ 585.1	$ 648.4	$ 782.5	$ 552.2
Operating income	77.9	124.2	263.2	69.2
Net income	23.8	52.1	147.4	19.5
Basic earnings per common share	0.15	0.34	0.96	0.12
Diluted earnings per common share	0.15	0.34	0.95	0.12

KCP&L	Quarter 1st	2nd	3rd	4th
2015	(millions)			
Operating revenue	$ 370.4	$ 417.4	$ 526.3	$ 399.7
Operating income	45.3	79.3	170.8	68.6
Net income	13.2	29.4	84.3	25.9
2014				
Operating revenue	$ 391.0	$ 439.5	$ 533.4	$ 366.9
Operating income	47.5	78.2	177.2	47.2
Net income	17.2	34.8	94.5	15.9

Quarterly data is subject to seasonal fluctuations with peak periods occurring in the summer months.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

GREAT PLAINS ENERGY

Disclosure Controls and Procedures
Great Plains Energy carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)). This evaluation was conducted under the supervision, and with the participation, of Great Plains Energy's management, including the chief executive officer and chief financial officer, and Great Plains Energy's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of Great Plains Energy have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Great Plains Energy were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting
There has been no change in Great Plains Energy's internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended December 31, 2015, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting
Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) for Great Plains Energy. Under the supervision and with the participation of Great Plains Energy's chief executive officer and chief financial officer, management evaluated the effectiveness of Great Plains Energy's internal control over financial reporting as of December 31, 2015. Management used for this evaluation the framework in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission.

Management has concluded that, as of December 31, 2015, Great Plains Energy's internal control over financial reporting is effective based on the criteria set forth in the COSO framework. Deloitte & Touche LLP, the independent registered public accounting firm that audited the financial statements included in this annual report on Form 10-K, has issued its attestation report on Great Plains Energy's internal control over financial reporting, which is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Great Plains Energy Incorporated
Kansas City, Missouri

We have audited the internal control over financial reporting of Great Plains Energy Incorporated and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2015, of the Company and our report dated February 24, 2016, expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 24, 2016

Disclosure Controls and Procedures

KCP&L carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15(e) under the Exchange Act). This evaluation was conducted under the supervision, and with the participation, of KCP&L's management, including the chief executive officer and chief financial officer, and KCP&L's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of KCP&L have concluded as of the end of the period covered by this report that the disclosure controls and procedures of KCP&L were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There has been no change in KCP&L's internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended December 31, 2015, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) for KCP&L. Under the supervision and with the participation of KCP&L's chief executive officer and chief financial officer, management evaluated the effectiveness of KCP&L's internal control over financial reporting as of December 31, 2015. Management used for this evaluation the framework in *Internal Control - Integrated Framework (2013)* issued by the COSO of the Treadway Commission.

Management has concluded that, as of December 31, 2015, KCP&L's internal control over financial reporting is effective based on the criteria set forth in the COSO framework. Deloitte & Touche LLP, the independent registered public accounting firm that audited the financial statements included in this annual report on Form 10-K, has issued its attestation report on KCP&L's internal control over financial reporting, which is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Kansas City Power & Light Company
Kansas City, Missouri

We have audited the internal control over financial reporting of Kansas City Power & Light Company and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2015, of the Company and our report dated February 24, 2016, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 24, 2016

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Great Plains Energy Directors

The information required by this item is incorporated by reference from the Great Plains Energy 2016 Proxy Statement (Proxy Statement), which will be filed with the SEC no later than March 26, 2016:

- Information regarding the directors of Great Plains Energy required by this item is contained in the Proxy Statement section titled "Election of Directors."
- Information regarding compliance with Section 16(a) of the Securities Exchange Act of 1934 required by this item is contained in the Proxy Statement section titled "Security Ownership of Certain Beneficial Owners, Directors and Officers - Section 16(a) Beneficial Ownership Reporting Compliance."
- Information regarding the Audit Committee of Great Plains Energy required by this item is contained in the Proxy Statement section titled "Corporate Governance - Committees of the Board."

Great Plains Energy and KCP&L Executive Officers

Information required by this item regarding the executive officers of Great Plains Energy and KCP&L is contained in this report in the Part I, Item 1 section titled "Executive Officers."

Great Plains Energy and KCP&L Code of Ethical Business Conduct

The Companies have adopted a Code of Ethical Business Conduct (Code), which applies to all directors, officers and employees of Great Plains Energy, KCP&L and their subsidiaries. The Code is posted on the corporate governance page of the Internet websites at www.greatplainsenergy.com and www.kcpl.com. A copy of the Code is available, without charge, upon written request to Corporate Secretary, Great Plains Energy Incorporated, 1200 Main St., Kansas City, Missouri 64105. Great Plains Energy and KCP&L intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of the Code that applies to the principal executive officer, principal financial officer, principal accounting officer or controller of those companies by posting such information on the corporate governance page of the Internet websites.

Other KCP&L Information

The other information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 11. EXECUTIVE COMPENSATION

Great Plains Energy

The information required by this item contained in the sections titled "Executive Compensation," "Director Compensation," "Compensation Discussion and Analysis", "Compensation Committee Report" and "Director Independence - Compensation Committee Interlocks and Insider Participation" of the Proxy Statement is incorporated by reference.

KCP&L

The other information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

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

Great Plains Energy
The information required by this item regarding security ownership of the directors and executive officers of Great Plains Energy contained in the section titled "Security Ownership of Certain Beneficial Owners, Directors and Officers" of the Proxy Statement is incorporated by reference.

KCP&L
The information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

Equity Compensation Plans
Great Plains Energy's Long-Term Incentive Plan is an equity compensation plan approved by its shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, restricted stock units, bonus shares, stock options, stock appreciation rights, limited stock appreciation rights, director shares, director deferred share units and performance shares to directors, officers and other employees of Great Plains Energy and KCP&L.

KCP&L does not have an equity compensation plan; however, KCP&L officers and certain employees participate in Great Plains Energy's Long-Term Incentive Plan.

The following table provides information, as of December 31, 2015, regarding the number of common shares to be issued upon exercise of outstanding options, warrants and rights, their weighted average exercise price, and the number of shares of common stock remaining available for future issuance. The table excludes shares issued or issuable under Great Plains Energy's defined contribution savings plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			
Great Plains Energy Long-Term Incentive Plan	724,425 (1)	$ — (2)	4,688,293
Equity compensation plans not approved by security holders	—	—	—
Total	724,425 (1)	$ — (2)	4,688,293

(1) Includes 609,010 performance shares at target performance levels and director deferred share units for 115,415 shares of Great Plains Energy common stock outstanding at December 31, 2015.
(2) The performance shares and director deferred share units have no exercise price and therefore are not reflected in the weighted average exercise price.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Great Plains Energy
The information required by this item contained in the sections titled "Director Independence" and "Related Party Transactions" of the Proxy Statement is incorporated by reference.

KCP&L
The information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Great Plains Energy
The information required by this item regarding the independent auditors of Great Plains Energy and its subsidiaries contained in the section titled "Ratification of Appointment of Independent Auditors" of the Proxy Statement is incorporated by reference.

KCP&L
The Audit Committee of the Great Plains Energy Board functions as the Audit Committee of KCP&L. The following table sets forth the aggregate fees billed by Deloitte & Touche LLP for audit services rendered in connection with the consolidated financial statements and reports for 2015 and 2014 and for other services rendered during 2015 and 2014 on behalf of KCP&L, as well as all out-of-pocket costs incurred in connection with these services:

Fee Category	2015	2014
Audit Fees	$ 1,201,819	$ 1,187,640
Audit-Related Fees	20,000	20,170
Tax Fees	5,751	—
All Other Fees	8,802	—
Total Fees	$ 1,236,372	$ 1,207,810

Audit Fees: Consists of fees billed for professional services rendered for the audits of the annual consolidated financial statements of KCP&L and reviews of the interim condensed consolidated financial statements included in quarterly reports. Audit fees also include: services provided by Deloitte & Touche LLP in connection with statutory and regulatory filings or engagements; audit reports on audits of the effectiveness of internal control over financial reporting and other attest services, except those not required by statute or regulation; services related to filings with the SEC, including comfort letters, consents and assistance with and review of documents filed with the SEC; and accounting research in support of the audit.

Audit-Related Fees: Consists of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of consolidated financial statements of KCP&L and are not reported under "Audit Fees". These services include consultation concerning financial accounting and reporting standards.

Tax Fees: Consists of fees billed for tax compliance and related support of tax returns and other tax services, including assistance with tax audits, and tax research and planning.

All Other Fees: Consists of fees for all other services other than those described above.

Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services
The Audit Committee has adopted policies and procedures for the pre-approval of all audit services, audit-related services, tax services and other services to be provided by the independent registered public accounting firm for KCP&L. The Audit Committee's policy is to pre-approve all audit, audit-related, tax or other services to be provided by the independent registered public accounting firm. Under these policies and procedures, the Audit Committee may pre-approve certain types of services, up to the aggregate fee levels it sets. Any proposed service within a pre-approved type of service that would cause the applicable fee level to be exceeded cannot be provided unless the Audit Committee either amends the applicable fee level or specifically approves the proposed service. The Audit Committee, as well, may specifically approve audit, audit-related, tax or other services on a case-by-case basis. Pre-approval is generally provided for up to one year, unless the Audit Committee specifically provides for a different period. The Company provides quarterly updates to the Audit Committee regarding actual fees spent with respect to pre-approved services. The Chairman of the Audit Committee may pre-approve audit, audit-related, tax and other services provided by the independent registered public accounting firm as required between meetings and report such pre-approval at the next Audit Committee meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Financial Statements

Financial Statement Schedules

Exhibits

Exhibit Number		Description of Document	Registrant
3.1	*	Articles of Incorporation of Great Plains Energy Incorporated, as amended effective May 6, 2014 (Exhibit 3.1 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy
3.2	*	Amended and Restated By-laws of Great Plains Energy Incorporated, as amended December 10, 2013 (Exhibit 3.1 to Form 8-K filed on December 16, 2013).	Great Plains Energy
3.3	*	Amended and Restated Articles of Consolidation of Kansas City Power & Light Company, restated as of May 6, 2014 (Exhibit 3.2 to Form 10-Q for the quarter ended March 31, 2014).	KCP&L
3.4	*	Amended and Restated By-laws of Kansas City Power & Light Company, as amended December 10, 2013 (Exhibit 3.3 to Form 8-K filed on December 16, 2013).	KCP&L
4.1	*	Indenture, dated as of June 1, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as trustee (Exhibit 4.4 to Form 8-A/A filed on June 14, 2004).	Great Plains Energy
4.2	*	First Supplemental Indenture, dated as of June 14, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as trustee (Exhibit 4.5 to Form 8-A/A filed on June 14, 2004).	Great Plains Energy
4.3	*	Second Supplemental Indenture, dated as of September 25, 2007, between Great Plains Energy Incorporated and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on September 26, 2007).	Great Plains Energy
4.4	*	Third Supplemental Indenture, dated as of August 13, 2010, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on August 13, 2010).	Great Plains Energy
4.5	*	Fourth Supplemental Indenture, dated as of May 19, 2011, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on May 19, 2011).	Great Plains Energy
4.6	*	Subordinated Indenture, dated as of May 18, 2009, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on May 19, 2009).	Great Plains Energy
4.7	*	Supplemental Indenture No. 1, dated as of May 18, 2009, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on May 19, 2009).	Great Plains Energy
4.8	*	Supplemental Indenture No. 2, dated as of March 22, 2012, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on March 23, 2012).	Great Plains Energy

4.9	*	Indenture, dated as of August 24, 2001, between Aquila, Inc. and BankOne Trust Company, N.A., as trustee (Exhibit 4(d) to Registration Statement on Form S-3 (File No. 333-68400) filed by Aquila, Inc. on August 27, 2001).	Great Plains Energy
4.10	*	Second Supplemental Indenture, dated as of July 3, 2002, between Aquila, Inc. and BankOne Trust Company, N.A., as trustee (Exhibit 4(c) to Form S-4 (File No: 333-100204) filed by Aquila, Inc. on September 30, 2002).	Great Plains Energy
4.11	*	General Mortgage and Deed of Trust, dated as of December 1, 1986, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4-bb to Form 10-K for the year ended December 31, 1986).	Great Plains Energy KCP&L
4.12	*	Fifth Supplemental Indenture, dated as of September 15, 1992, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4-a to Form 10-Q for the quarter ended September 30, 1992).	Great Plains Energy KCP&L
4.13	*	Seventh Supplemental Indenture, dated as of October 1, 1993, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4-a to Form 10-Q for the quarter ended September 30, 1993).	Great Plains Energy KCP&L
4.14	*	Eighth Supplemental Indenture, dated as of December 1, 1993, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4-o to Registration Statement, Registration No. 33-51799).	Great Plains Energy KCP&L
4.15	*	Eleventh Supplemental Indenture, dated as of August 15, 2005, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.2 to Form 10-Q for the quarter ended September 30, 2005).	Great Plains Energy KCP&L
4.16	*	Twelfth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.2 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L
4.17	*	Thirteenth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.3 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L
4.18	*	Fourteenth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.4 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L

4.19	*	Fifteenth Supplemental Indenture, dated as of June 30, 2011, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Form 10-Q for the quarter ended June 30, 2011).	Great Plains Energy KCP&L
4.20	*	Indenture, dated as of December 1, 2000, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4(a) to Form 8-K filed on December 18, 2000).	Great Plains Energy KCP&L
4.21	*	Indenture, dated as of March 1, 2002, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4.1.b. to Form 10-Q for the quarter ended March 31, 2002).	Great Plains Energy KCP&L
4.22	*	Supplemental Indenture No. 1, dated as of November 15, 2005, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4.2.j to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
4.23	*	Indenture, dated as of May 1, 2007, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on June 4, 2007).	Great Plains Energy KCP&L
4.24	*	Supplemental Indenture No. 1, dated as of June 4, 2007, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on June 4, 2007).	Great Plains Energy KCP&L
4.25	*	Supplemental Indenture No. 2, dated as of March 11, 2008, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on March 11, 2008).	Great Plains Energy KCP&L
4.26	*	Supplemental Indenture No. 3, dated as of September 20, 2011, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on September 20, 2011).	Great Plains Energy KCP&L
4.27	*	Supplemental Indenture No. 4, dated as of March 14, 2013, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on March 14, 2013).	Great Plains Energy KCP&L
4.28	*	Supplemental Indenture No. 5, dated as of August 18, 2015, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on August 18, 2015).	Great Plains Energy KCP&L
4.29	*	Note Purchase Agreement, dated August 16, 2013, among KCP&L Greater Missouri Operations Company and the purchasers party thereto (Exhibit 4.1 to Form 8-K filed on August 19, 2013).	Great Plains Energy
10.1	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, effective on May 7, 2002 (Exhibit 10.1.a to Form 10-K for the year ended December 31, 2002).	Great Plains Energy KCP&L
10.2	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on May 3, 2011 (Exhibit 10.1 to Form 8-K filed on May 6, 2011).	Great Plains Energy KCP&L

10.3	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on January 1, 2014 (Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2013).	Great Plains Energy KCP&L
10.4	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2012 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2012).	Great Plains Energy KCP&L
10.5	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2013 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.6	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2014 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.7	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2015 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.8	*+	Form of 2012 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2012).	Great Plains Energy KCP&L
10.9	*+	Form of 2012 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2012).	Great Plains Energy KCP&L
10.10	*+	Form of 2013 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.11	*+	Form of 2013 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.12	*+	Form of 2014 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.13	*+	Form of 2014 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.14	*+	Form of 2015 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.15	*+	Form of 2015 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.16	*+	Aquila, Inc. 2002 Omnibus Incentive Compensation Plan (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2002, filed by Aquila, Inc.).	Great Plains Energy
10.17	*+	Great Plains Energy Incorporated, Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company Annual Incentive Plan amended effective as of January 1, 2015 (Exhibit 10.4 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L

10.18	*+	Form of Indemnification Agreement with each officer and director (Exhibit 10-f to Form 10-K for year ended December 31, 1995).	Great Plains Energy KCP&L
10.19	*+	Form of Conforming Amendment to Indemnification Agreement with each officer and director (Exhibit 10.1.a to Form 10-Q for the quarter ended March 31, 2003).	Great Plains Energy KCP&L
10.20	*+	Form of Indemnification Agreement with each director and officer (Exhibit 10.1 to Form 8-K filed on December 8, 2008).	Great Plains Energy KCP&L
10.21	*+	Form of Indemnification Agreement with officers and directors (Exhibit 10.1.p to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.22	*+	Form of Indemnification Agreement with officers and directors (Exhibit 10.1 to Form 8-K filed on December 16, 2013).	Great Plains Energy KCP&L
10.23	*+	Form of Change in Control Severance Agreement with other executive officers of Great Plains Energy Incorporated and Kansas City Power & Light Company (Exhibit 10.1.e to Form 10-Q for the quarter ended September 30, 2006).	Great Plains Energy KCP&L
10.24	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A) (Exhibit 10.1.10 to Form 10-Q for the quarter ended September 30, 2007).	Great Plains Energy KCP&L
10.25	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A), as amended February 10, 2009 (Exhibit 10.1.29 to Form 10-K for the year ended December 31, 2008	Great Plains Energy KCP&L
10.26	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A), as amended December 8, 2009 (Exhibit 10.1.27 to Form 10-K for the year ended December 31, 2009).	Great Plains Energy KCP&L
10.27	*+	Amendment dated October 28, 2014, to the Great Plains Energy Incorporated Supplemental Executive Retirement Plan as amended and restated on December 8, 2009 (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2014).	Great Plains Energy KCP&L
10.28	*+	Great Plains Energy Incorporated Nonqualified Deferred Compensation Plan (As Amended and Restated for I.R.C. §409A) (Exhibit 10.1.11 to Form 10-Q for the quarter ended September 30, 2007).	Great Plains Energy KCP&L
10.29	*+	Great Plains Energy Incorporated Nonqualified Deferred Compensation Plan (As Amended and Restated for I.R.C. §409A), amended effective January 1, 2010 (Exhibit 10.1.5 to Form 10-Q for the quarter ended March 31, 2010).	Great Plains Energy KCP&L

10.30	*+	Retirement Agreement, dated as of May 22, 2012 between Great Plains Energy Incorporated, Kansas City Power & Light Company, KCP&L Greater Missouri Operations Company and Michael J. Chesser (Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2012).	Great Plains Energy KCP&L
10.31	*	Joint Motion and Settlement Agreement, dated as of February 26, 2008, among Great Plains Energy Incorporated, Kansas City Power & Light Company, the Kansas Corporation Commission Staff, the Citizens' Utility Ratepayers Board, Aquila, Inc. d/b/a Aquila Networks, Black Hills Corporation, and Black Hills/Kansas Gas Utility Company, LLC (Exhibit 10.1.7 to Form 10-Q for the quarter ended March 31, 2008).	Great Plains Energy KCP&L
10.32	*	Credit Agreement, dated as of August 9, 2010, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Barclays Bank PLC and U.S. Bank National Association, as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy
10.33	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among Great Plains Energy Incorporated, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, Barclays Bank PLC and U.S. Bank National Association, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.59 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy
10.34	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A. and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy
10.35	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.37 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy

10.36	*	Credit Agreement, dated as of August 9, 2010, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, JPMorgan Chase Bank, N.A. and The Bank of Nova Scotia, as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy KCP&L
10.37	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among Kansas City Power & Light Company, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, JPMorgan Chase Bank, N.A. and The Bank of Nova Scotia, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.61 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy KCP&L
10.38	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy KCP&L
10.39	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.41 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy KCP&L
10.40	*	Credit Agreement, dated as of August 9, 2010, among KCP&L Greater Missouri Operations Company, Great Plains Energy Incorporated, as Guarantor, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, The Royal Bank of Scotland PLC and BNP Paribas , as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy

10.41	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among KCP&L Greater Missouri Operations Company, Great Plains Energy Incorporated, as Guarantor, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, The Royal Bank of Scotland PLC and BNP Paribas, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.63 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy
10.42	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among KCP&L Greater Missouri Operations Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy
10.43	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among KCP&L Greater Missouri Operations Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.45 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy
10.44	*	Guaranty, dated as of July 15, 2008, issued by Great Plains Energy Incorporated in favor of Union Bank of California, N.A., as successor trustee, and the holders of the Aquila, Inc., 8.27% Senior Notes due November 15, 2021 (Exhibit 10.6 to Form 8-K filed on July 18, 2008).	Great Plains Energy
10.45	*	Insurance Agreement, dated as of September 1, 2005, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2.e to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.46	*	Insurance Agreement, dated as of September 1, 2005, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2.f to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.47	*	Purchase and Sale Agreement, dated as of July 1, 2005, between Kansas City Power & Light Company, as Originator, and Kansas City Power & Light Receivables Company, as Buyer (Exhibit 10.2.b to Form 10-Q for the quarter ended June 30, 2005).	Great Plains Energy KCP&L

10.48	*	Receivables Sale Agreement, dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent, and Victory Receivables Corporation (Exhibit 10.2.c to Form 10-Q for the quarter ended June 30, 2005).	Great Plains Energy KCP&L
10.49	*	Amendment No. 1, dated as of April 2, 2007, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation to the Receivables Sale Agreement dated as of July 1, 2005 (Exhibit 10.2.2 to Form 10-Q for the quarter ended March 31, 2007).	Great Plains Energy KCP&L
10.50	*	Amendment No. 2, dated as of July 11, 2008, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation to the Receivables Sale Agreement dated as of July 1, 2005 (Exhibit 10.2.2 to Form 10-Q for the quarter ended June 30, 2008).	Great Plains Energy KCP&L
10.51	*	Amendment, dated as of July 9, 2009, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.4 to Form 8-K filed on July 13, 2009).	Great Plains Energy KCP&L
10.52	*	Amendment and Waiver, dated as of September 25, 2009, to the Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.2.2 to Form 10-Q for the quarter ended September 30, 2009).	Great Plains Energy KCP&L
10.53	*	Amendment, dated as of May 5, 2010, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.2.2 to Form 10-Q for the quarter ended March 31, 2010).	Great Plains Energy KCP&L
10.54	*	Amendment, dated as of February 23, 2011, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation. (Exhibit 10.5 to Form 10-Q for the quarter ended March 31, 2011).	Great Plains Energy KCP&L
10.55	*	Amendment, dated as of September 9, 2011, to Receivables Sale Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.1 to Form 8-K filed on September 13, 2011).	Great Plains Energy KCP&L

10.56	*	Amendment dated as of September 9, 2014, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 15, 2014).	Great Plains Energy KCP&L
10.57	*	Amendment dated as of September 9, 2015, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 11, 2015).	Great Plains Energy KCP&L
10.58	*	Purchase and Sale Agreement, dated as of May 31, 2012, between KCP&L Greater Missouri Operations Company, as Originator, and GMO Receivables Company, as Buyer (Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2012).	Great Plains Energy
10.59	*	Receivables Sale Agreement, dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent, and Victory Receivables Corporation (Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2012).	Great Plains Energy
10.60	*	First Amendment dated as of September 9, 2014, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser. (Exhibit 10.2 to Form 8-K filed on September 15, 2014).	Great Plains Energy
10.61	*	Second Amendment dated as of September 9, 2015, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser. (Exhibit 10.2 to Form 8-K filed on September 11, 2015).	Great Plains Energy
10.62	*	Iatan Unit 2 and Common Facilities Ownership Agreement, dated as of May 19, 2006, among Kansas City Power & Light Company, Aquila, Inc., The Empire District Electric Company, Kansas Electric Power Cooperative, Inc., and Missouri Joint Municipal Electric Utility Commission (Exhibit 10.2.a to Form 10-Q for the quarter ended June 30, 2006).	Great Plains Energy KCP&L
10.63	*	Joint Motion and Settlement Agreement dated as of February 26, 2008, among Great Plains Energy Incorporated, Kansas City Power & Light Company, the Kansas Corporation Commission Staff, the Citizens' Utility Ratepayers Board, Aquila, Inc. d/b/a Aquila Networks, Black Hills Corporation, and Black Hills/ Kansas Gas Utility Company, LLC (Exhibit 10.1.7 to Form 10-Q for the quarter ended March 31, 2008).	Great Plains Energy KCP&L

10.64	*	Stipulation and Agreement dated April 24, 2009, among Kansas City Power & Light Company, Staff of the Missouri Public Service Commission, Office of Public Counsel, Praxair, Inc., Midwest Energy Users Association, U.S. Department of Energy and the U.S. Nuclear Security Administration, Ford Motor Company, Missouri Industrial Energy Consumers and Missouri Department of Natural Resources (Exhibit 10.1 to Form 8-K filed April 30, 2009).	Great Plains Energy KCP&L
10.65	*	Non-Unanimous Stipulation and Agreement dated May 22, 2009 among KCP&L Greater Missouri Operations Company, the Staff of the Missouri Public Service Commission, the Office of the Public Counsel, Missouri Department of Natural Resources and Dogwood Energy, LLC (Exhibit 10.1 to Form 8-K filed on May 27, 2009).	Great Plains Energy
10.66	*	Collaboration Agreement dated as of March 19, 2007, among Kansas City Power & Light Company, Sierra Club and Concerned Citizens of Platte County, Inc. (Exhibit 10.1 to Form 8-K filed on March 20, 2007).	Great Plains Energy KCP&L
10.67	*	Amendment to the Collaboration Agreement effective as of September 5, 2008 among Kansas City Power & Light Company, Sierra Club and Concerned Citizens of Platte County, Inc. (Exhibit 10.2.20 to Form 10-K for the year ended December 31, 2009).	Great Plains Energy KCP&L
10.68	*	Joint Operating Agreement between Kansas City Power & Light Company and Aquila, Inc., dated as of October 10, 2008 (Exhibit 10.2.2 to Form 10-Q for the quarter ended September 30, 2008).	Great Plains Energy KCP&L
12.1		Computation of Ratio of Earnings to Fixed Charges.	Great Plains Energy
12.2		Computation of Ratio of Earnings to Fixed Charges.	KCP&L
21.1		List of Subsidiaries of Great Plains Energy Incorporated.	Great Plains Energy
23.1		Consent of Independent Registered Public Accounting Firm.	Great Plains Energy
23.2		Consent of Independent Registered Public Accounting Firm.	KCP&L
24.1		Powers of Attorney.	Great Plains Energy
24.2		Powers of Attorney.	KCP&L
31.1		Rule 13a-14(a)/15d-14(a) Certification of Terry Bassham.	Great Plains Energy
31.2		Rule 13a-14(a)/15d-14(a) Certification of Kevin E. Bryant.	Great Plains Energy
31.3		Rule 13a-14(a)/15d-14(a) Certification of Terry Bassham.	KCP&L
31.4		Rule 13a-14(a)/15d-14(a) Certification of Kevin E. Bryant.	KCP&L
32.1	**	Section 1350 Certifications.	Great Plains Energy
32.2	**	Section 1350 Certifications.	KCP&L

101.INS	XBRL Instance Document.	Great Plains Energy KCP&L
101.SCH	XBRL Taxonomy Extension Schema Document.	Great Plains Energy KCP&L
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.	Great Plains Energy KCP&L
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.	Great Plains Energy KCP&L
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.	Great Plains Energy KCP&L
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	Great Plains Energy KCP&L

* Filed with the SEC as exhibits to prior SEC filings and are incorporated herein by reference and made a part hereof. The SEC filings and the exhibit number of the documents so filed, and incorporated herein by reference, are stated in parenthesis in the description of such exhibit.

** Furnished and shall not be deemed filed for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act). Such document shall not be incorporated by reference into any registration statement or other document pursuant to the Exchange Act or the Securities Act of 1933, as amended, unless otherwise indicated in such registration statement or other document.

+ Indicates management contract or compensatory plan or arrangement.

Copies of any of the exhibits filed with the SEC in connection with this document may be obtained from KCP&L upon written request.

The registrants agree to furnish to the SEC upon request any instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of total assets of such registrant and its subsidiaries on a consolidated basis.

Schedule I - Parent Company Financial Statements

GREAT PLAINS ENERGY INCORPORATED

Statements of Comprehensive Income of Parent Company

Year Ended December 31	2015	2014	2013
Operating Expenses	(millions, except per share amounts)		
General and administrative	$ **0.9**	$ 1.1	$ 1.0
General taxes	**0.2**	0.4	0.6
Total	**1.1**	1.5	1.6
Operating loss	**(1.1)**	(1.5)	(1.6)
Equity in earnings from subsidiaries	**220.9**	251.1	256.5
Non-operating income	**29.7**	33.1	45.8
Interest charges	**(40.3)**	(44.3)	(54.7)
Income before income taxes	**209.2**	238.4	246.0
Income tax benefit	**3.8**	4.4	4.2
Net income	**213.0**	242.8	250.2
Preferred stock dividend requirements	**1.6**	1.6	1.6
Earnings available for common shareholders	$ **211.4**	$ 241.2	$ 248.6
Average number of basic common shares outstanding	**154.2**	153.9	153.5
Average number of diluted common shares outstanding	**154.8**	154.1	153.7
Basic and diluted earnings per common share	$ **1.37**	$ 1.57	$ 1.62
Comprehensive Income			
Net income	$ **213.0**	$ 242.8	$ 250.2
Other comprehensive income			
Derivative hedging activity			
Reclassification to expenses	**0.5**	4.4	9.9
Income tax expense	**(0.1)**	(1.7)	(3.9)
Net reclassification to expenses	**0.4**	2.7	6.0
Derivative hedging activity, net of tax	**0.4**	2.7	6.0
Other comprehensive income from subsidiaries, net of tax	**6.3**	3.9	7.1
Total other comprehensive income	**6.7**	6.6	13.1
Comprehensive income	$ **219.7**	$ 249.4	$ 263.3

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Balance Sheets of Parent Company

	December 31 2015	December 31 2014
ASSETS	(millions, except share amounts)	
Current Assets		
Accounts receivable from subsidiaries	$ 4.1	$ 4.0
Notes receivable from subsidiaries	2.0	0.6
Money pool receivable	3.7	3.3
Other	0.4	1.0
Total	10.2	8.9
Investments and Other Assets		
Investment in KCP&L	2,433.1	2,275.0
Investment in other subsidiaries	1,385.9	1,465.9
Note receivable from subsidiaries	634.9	634.9
Deferred income taxes	34.8	32.8
Other	1.6	2.0
Total	4,490.3	4,410.6
Total	$ 4,500.5	$ 4,419.5
LIABILITIES AND CAPITALIZATION		
Current Liabilities		
Notes payable	$ 10.0	$ 4.0
Accounts payable to subsidiaries	31.7	30.4
Accrued taxes	4.5	4.3
Accrued interest	4.1	4.1
Other	9.5	2.2
Total	59.8	45.0
Deferred Credits and Other Liabilities	7.1	11.4
Capitalization		
Great Plains Energy common shareholders' equity		
Common stock - 250,000,000 shares authorized without par value 154,504,900 and 154,254,037 shares issued, stated value	2,646.7	2,639.3
Retained earnings	1,024.4	967.8
Treasury stock - 101,229 and 91,281 shares, at cost	(2.6)	(2.3)
Accumulated other comprehensive loss	(12.0)	(18.7)
Total	3,656.5	3,586.1
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	10.0	10.0
4.50% - 100,000 shares issued	10.0	10.0
4.20% - 70,000 shares issued	7.0	7.0
4.35% - 120,000 shares issued	12.0	12.0
Total	39.0	39.0
Long-term debt	738.1	738.0
Total	4,433.6	4,363.1
Commitments and Contingencies		
Total	$ 4,500.5	$ 4,419.5

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Statements of Cash Flows of Parent Company

Year Ended December 31	2015	2014	2013
Cash Flows from Operating Activities		(millions)	
Net income	$ 213.0	$ 242.8	$ 250.2
Adjustments to reconcile income to net cash from operating activities:			
Amortization	0.8	4.8	10.6
Deferred income taxes, net	(1.7)	(1.4)	(10.5)
Equity in earnings from subsidiaries	(220.9)	(251.1)	(256.5)
Cash flows affected by changes in:			
Accounts receivable from subsidiaries	(0.1)	(3.8)	(0.1)
Taxes receivable	—	0.2	(0.2)
Accounts payable to subsidiaries	1.3	(3.2)	(0.5)
Other accounts payable	—	—	0.1
Accrued taxes	0.3	4.3	(0.1)
Accrued interest	—	(0.1)	(2.6)
Cash dividends from subsidiaries	157.0	144.0	140.0
Uncertain tax positions	—	(2.9)	7.3
Other	8.7	11.8	6.8
Net cash from operating activities	158.4	145.4	144.5
Cash Flows from Investing Activities			
Intercompany lending	(1.4)	—	248.7
Net money pool lending	(0.4)	6.1	(5.4)
Investment in subsidiary	(7.8)	(3.6)	(0.5)
Net cash from investing activities	(9.6)	2.5	242.8
Cash Flows from Financing Activities			
Issuance of common stock	3.0	4.8	4.9
Issuance fees	—	(0.1)	(0.4)
Repayment of long-term debt	—	—	(250.0)
Net change in short-term borrowings	6.0	(5.0)	(3.0)
Dividends paid	(155.5)	(145.6)	(137.3)
Other financing activities	(2.3)	(2.0)	(1.5)
Net cash from financing activities	(148.8)	(147.9)	(387.3)
Net Change in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of Year	—	—	—
Cash and Cash Equivalents at End of Year	$ —	$ —	$ —

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
NOTES TO FINANCIAL STATEMENTS OF PARENT COMPANY

The Great Plains Energy Incorporated Notes to Consolidated Financial Statements in Part II, Item 8 should be read in conjunction with the Great Plains Energy Incorporated Parent Company Financial Statements.

The Great Plains Energy Incorporated Parent Company Financial Statements have been prepared to present the financial position, results of operations and cash flows of Great Plains Energy on a stand-alone basis as a holding company. Investments in subsidiaries are accounted for using the equity method.

Schedule II - Valuation and Qualifying Accounts and Reserves

Great Plains Energy Incorporated

Valuation and Qualifying Accounts

Years Ended December 31, 2015, 2014 and 2013

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End Of Period
			(millions)		
Year Ended December 31, 2015					
Allowance for uncollectible accounts	$ 2.8	$ 10.5	$ 8.7 (a)	$ 18.2 (b)	$ 3.8
Legal reserves	4.7	2.6	—	1.4 (c)	5.9
Environmental reserves	1.7	—	—	—	1.7
Tax valuation allowance	16.6	4.9	—	1.6 (d)	19.9
Year Ended December 31, 2014					
Allowance for uncollectible accounts	$ 2.5	$ 11.4	$ 8.5 (a)	$ 19.6 (b)	$ 2.8
Legal reserves	4.6	2.7	—	2.6 (c)	4.7
Environmental reserves	1.7	—	—	—	1.7
Tax valuation allowance	20.7	0.5	—	4.6 (d)	16.6
Year Ended December 31, 2013					
Allowance for uncollectible accounts	$ 6.9	$ 12.3	$ 7.6 (a)	$ 24.3 (b)	$ 2.5
Legal reserves	4.6	2.7	—	2.7 (c)	4.6
Environmental reserves	2.3	—	—	0.6	1.7
Tax valuation allowance	23.8	0.1	—	3.2 (d)	20.7

(a) Recoveries.
(b) Uncollectible accounts charged off.
(c) Payment of claims.
(d) Reversal of tax valuation allowance.

Kansas City Power & Light Company

Valuation and Qualifying Accounts

Years Ended December 31, 2015, 2014 and 2013

		Additions			
Description	**Balance At Beginning Of Period**	**Charged To Costs And Expenses**	**Charged To Other Accounts**	**Deductions**	**Balance At End Of Period**
			(millions)		
Year Ended December 31, 2015					
Allowance for uncollectible accounts	$ 1.2	$ 7.1	$ 5.8 (a)	$ 12.3 (b)	$ 1.8
Legal reserves	2.9	2.6	—	0.2 (c)	5.3
Environmental reserves	0.3	—	—	—	0.3
Tax valuation allowance	—	0.7	—	—	0.7
Year Ended December 31, 2014					
Allowance for uncollectible accounts	$ 1.1	$ 7.6	$ 5.5 (a)	$ 13.0 (b)	$ 1.2
Legal reserves	2.9	2.3	—	2.3 (c)	2.9
Environmental reserves	0.3	—	—	—	0.3
Year Ended December 31, 2013					
Allowance for uncollectible accounts	$ 1.5	$ 8.0	$ 5.0 (a)	$ 13.4 (b)	$ 1.1
Legal reserves	2.9	0.9	—	0.9 (c)	2.9
Environmental reserves	0.3	—	—	—	0.3

(a) Recoveries.
(b) Uncollectible accounts charged off.
(c) Payment of claims.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

GREAT PLAINS ENERGY INCORPORATED

Date: February 24, 2016

By: /s/ Terry Bassham
Terry Bassham
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities 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.

Signature	Title	Date
/s/ Terry Bassham Terry Bassham	Chairman, President and Chief Executive Officer (Principal Executive Officer)	
/s/ Kevin E. Bryant Kevin E. Bryant	Senior Vice President – Finance and Strategy and Chief Financial Officer (Principal Financial Officer)	
/s/ Steven P. Busser Steven P. Busser	Vice President – Business Planning and Controller (Principal Accounting Officer)	
David L. Bodde*	Director	
Randall C. Ferguson, Jr.*	Director	February 24, 2016
Gary D. Forsee*	Director	
Scott D. Grimes*	Director	
Thomas D. Hyde*	Director	
James A. Mitchell*	Director	
Ann D. Murtlow*	Director	
John J. Sherman*	Director	
Linda H. Talbott*	Director	

*By /s/ Terry Bassham
Terry Bassham
Attorney-in-Fact*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

KANSAS CITY POWER & LIGHT COMPANY

Date: February 24, 2016

By: /s/ Terry Bassham
Terry Bassham
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities 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.

Signature	Title	Date
/s/ Terry Bassham Terry Bassham	Chairman, President and Chief Executive Officer (Principal Executive Officer)	)
/s/ Kevin E. Bryant Kevin E. Bryant	Senior Vice President - Finance and Strategy and Chief Financial Officer (Principal Financial Officer)	)
/s/ Steven P. Busser Steven P. Busser	Vice President - Business Planning and Controller (Principal Accounting Officer)	)
David L. Bodde*	Director	)
Randall C. Ferguson, Jr.*	Director	) February 24, 2016
Gary D. Forsee*	Director	)
Scott D. Grimes*	Director	)
Thomas D. Hyde*	Director	)
James A. Mitchell*	Director	)
Ann D. Murtlow*	Director	)
John J. Sherman*	Director	)
Linda H. Talbott*	Director	)

*By /s/ Terry Bassham
Terry Bassham
Attorney-in-Fact*

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DIRECTORS AND OFFICERS

BOARD OF DIRECTORS Great Plains Energy

TERRY BASSHAM
Chairman of the Board, President and Chief Executive Officer

DR. DAVID L. BODDE
Professor, Clemson University

RANDALL C. FERGUSON, JR.
Former Senior Partner for Business Development, Tshibanda & Associates, LLC, a consulting and project management services firm

GARY D. FORSEE
Former President, University of Missouri System

SCOTT D. GRIMES
Chief Executive Officer and Founder, Cardlytics, Inc., an international technology company

THOMAS D. HYDE
Former Executive Vice President, Legal, Compliance, Ethics and Corporate Secretary, Wal-Mart Stores, Inc.

JAMES A. MITCHELL
Executive Fellow - Leadership, Center for Ethical Business Cultures, a non-profit organization assisting business leaders in creating ethical and profitable cultures

ANN D. MURTLOW
President and Chief Executive Officer, United Way of Central Indiana

JOHN J. SHERMAN
Director of Crestwood Equity GP LLC and former Chief Executive Officer, President and Director, NRGM GP, LLC

DR. LINDA H. TALBOTT
President and Chief Executive Officer, Talbott & Associates, consultants in strategic planning, philanthropic management and development

OFFICERS Great Plains Energy

TERRY BASSHAM
Chairman of the Board, President and Chief Executive Officer

KEVIN E. BRYANT
Senior Vice President - Finance and Strategy and Chief Financial Officer

STEVEN P. BUSSER
Vice President - Risk Management and Controller

CHARLES A. CAISLEY
Vice President - Marketing and Public Affairs

ELLEN E. FAIRCHILD
Vice President, Chief Compliance Officer and Corporate Secretary

HEATHER A. HUMPHREY
Senior Vice President - Corporate Services and General Counsel

LORI A. WRIGHT
Vice President - Corporate Planning, Investor Relations and Treasurer

OFFICERS KCP&L

TERRY BASSHAM
Chairman of the Board, President and Chief Executive Officer

DUANE D. ANSTAETT
Vice President - Generation

KEVIN E. BRYANT
Senior Vice President - Finance and Strategy and Chief Financial Officer

STEVEN P. BUSSER
Vice President - Risk Management and Controller

CHARLES A. CAISLEY
Vice President - Marketing and Public Affairs

MICHAEL L. DEGGENDORF
Senior Vice President

ELLEN E. FAIRCHILD
Vice President, Chief Compliance Officer and Corporate Secretary

SCOTT H. HEIDTBRINK
Executive Vice President and Chief Operating Officer

HEATHER A. HUMPHREY
Senior Vice President - Corporate Services and General Counsel

DARRIN R. IVES
Vice President - Regulatory Affairs

MARIA R. JENKS
Vice President - Supply Chain

CHARLES L. KING
Vice President and Chief Information Officer

KEVIN T. NOBLET
Vice President - Delivery

LORI A. WRIGHT
Vice President - Corporate Planning, Investor Relations and Treasurer

SHAREHOLDER INFORMATION

GREAT PLAINS ENERGY FORM 10-K
Great Plains Energy's 2015 annual report on Form 10-K filed with the Securities and Exchange Commission can be found at www.greatplainsenergy.com. The 10-K is available at no charge upon written request to:

Corporate Secretary
Great Plains Energy Incorporated
P.O. Box 418679
Kansas City, MO 64141-9679

MARKET INFORMATION
Great Plains Energy common stock is traded on the New York Stock Exchange under the ticker symbol "GXP." We had 15,672 shareholders of record as of February 23, 2016.

INTERNET SITE
We have a website at www.greatplainsenergy.com. Information available includes our SEC filings, news releases, stock quotes, customer account information, community and environmental efforts and information of general interest to investors and customers.

Also located on the website are our Code of Ethical Business Conduct, Corporate Governance Guidelines and the charters of the Audit Committee, Governance Committee and Compensation and Development Committee of the Board of Directors, which are available at no charge upon written request to the Corporate Secretary.

COMMON STOCK DIVIDEND

QUARTER	2015	2014
First	$0.245	$0.23
Second	0.245	0.23
Third	0.245	0.23
Fourth	0.2625	0.245

CUMULATIVE PREFERRED STOCK DIVIDENDS
Quarterly dividends on preferred stock were declared in each quarter of 2015 and 2014 as follows:

SERIES	AMOUNT	SERIES	AMOUNT
3.80%	$0.95	4.35%	$1.0875
4.20%	1.05	4.50%	1.125

TWO-YEAR COMMON STOCK HISTORY

	2015		2014	
QUARTER	HIGH	LOW	HIGH	LOW
First	$30.06	$25.80	$27.04	$23.85
Second	27.52	24.16	27.22	25.02
Third	27.35	24.21	26.80	24.17
Fourth	28.02	25.74	29.38	24.21

ANNUAL MEETING OF SHAREHOLDERS
Great Plains Energy's annual meeting of shareholders will be held at 10:00 a.m., May 3, 2016, at Great Plains Energy, One Kansas City Place, 1200 Main Street, Kansas City, MO 64105.

REGISTERED SHAREHOLDER INQUIRIES
For account information or assistance, including change of address, stock transfers, dividend payments, duplicate accounts or to report a lost certificate, please contact Investor Relations at 800-245-5275.

FINANCIAL COMMUNITY INQUIRIES
Securities analysts and investment professionals seeking information about Great Plains Energy may contact Investor Relations at 816-556-2312.

TRANSFER AGENT AND STOCK REGISTRANT
Computershare Trust Company, N.A. Investor Services
P. O. Box 30170
College Station, TX 77842-3170
Tel: 866-239-8177

ABOUT THE COMPANIES

Headquartered in Kansas City, Mo., Great Plains Energy Incorporated (NYSE: GXP) is the holding company of Kansas City Power & Light Company (KCP&L) and KCP&L Greater Missouri Operations Company (GMO), two of the leading regulated providers of electricity in the Midwest. KCP&L and GMO use KCP&L as a brand name. More information about the companies is available on the internet at: www.greatplainsenergy.com or www.kcpl.com.

NYSE: GXP

GREAT PLAINS ENERGY

Contents

KEPCo Staff

Marcus Harris................Executive Vice President & Chief Executive Officer

Les Evans..........................Senior Vice President & Chief Operating Officer

William Riggins.........Senior Vice President, Chief Strategic Officer & General Counsel

Coleen Wells................................Vice President & Chief Financial Officer

Stephanie Anderson................................Finance & Benefits Analyst 2

Mark Barbee.........Vice President of Engineering, KSI Vice President of Engineering

Chris Davidson....................................Engineer 3

Terry Deutscher........................Manager, SCADA & Meter Maintenance

Mark Doljac...........Director of Rates & Regulation

Carol Gardner.........................Operations Analyst

Shawn Geil..........Director of Information Systems

Maurice Hall.......Sr. SCADA/Metering Technician

Robert Hammersmith.........................Sr. SCADA/ Metering Technician

Shari Koch............................Finance & Accounts Payable/Payroll Specialist 2

Elizabeth Lesline...........Administrative Assistant/ Receptionist

Mitch Long.. Sr. SCADA/ Metering Technician

Matt Ottman......Information System Specialist 2

John Payne..............................Senior Engineer

Rita Petty.............................. Executive Assistant & Manager of Office Services

Kelsey Schrempp........... Administrative Assistant & Benefits Specialist

Paul Stone.................................System Operator

Jill Taggart......Director of Forecasting & Planning

Phil Wages............ Director of Member Services, Government Affairs & Business Development

Organization and Resources

Kansas Electric Power Cooperative, Inc. (KEPCo), headquartered in Topeka, Kansas, was incorporated in 1975 as a not-for-profit generation and transmission cooperative (G&T). It is KEPCo's responsibility to procure an adequate and reliable power supply for its nineteen distribution rural electric cooperative members at a reasonable cost.

Through their combined resources, KEPCo Members support a wide range of other services, such as rural economic development, marketing and diversification opportunities, power requirement and engineering studies, and rate design, among others.

KEPCo is governed by a Board of Trustees representing each of its nineteen Members which collectively serve more than 120,000 electric meters in two-thirds of Kansas. The KEPCo Board of Trustees meets regularly to establish policies and act on issues that often include recommendations from working committees of the Board and KEPCo staff. The Board also elects a seven-person Executive Committee which includes the President, Vice President, Secretary, Treasurer, and three additional Executive Committee members.

KEPCo was granted a limited certificate of convenience and authority by the Kansas Corporation Commission in 1980 to act as a G&T public utility. KEPCo's power supply resources consist of: 70 MW of owned generation from the Wolf Creek Generating Station; 30 MW of owned generation from the Iatan 2 Generating Unit; the 20 MW Sharpe Generating Station located in Coffey County; hydropower purchases of an equivalent 100 MW from the Southwestern Power Administration; and 13 MW from the Western Area Power Administration; plus partial requirement power purchases from regional utilities.

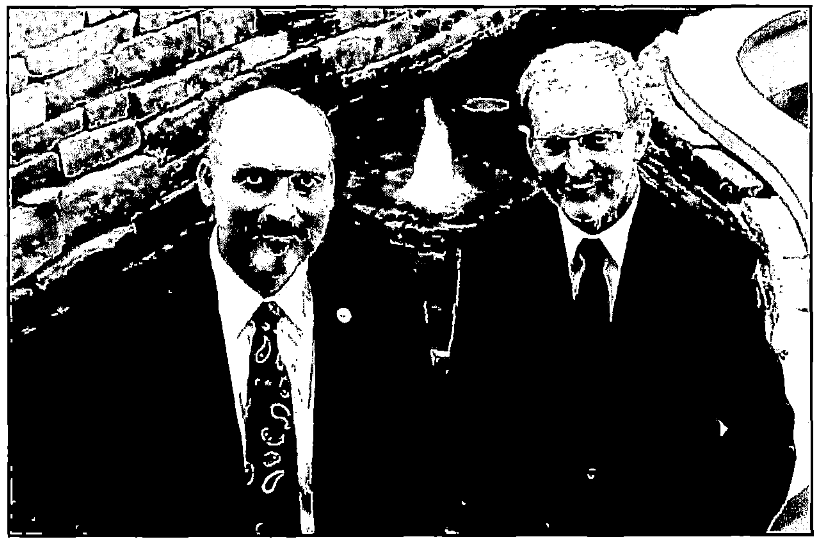
KEPCo is a Touchstone Energy® Cooperative. Touchstone Energy® is a nationwide alliance of more than 750 cooperatives committed to promoting the core strengths of electric cooperatives - integrity, accountability, innovation, personal service and a legacy of community commitment. The national program is anchored by the motto "The Power of Human Connections."

Kansas Electric
Power Cooperative, Inc.
P.O. Box 4877 Topeka, KS 66604
600 SW Corporate View Topeka, KS 66615
(785) 273-7010 www.kepco.org

A Touchstone Energy® Cooperative

2015 Message

from
Scott Whittington
KEPCo President
&
Marcus Harris
Executive Vice President
& Chief Executive Officer

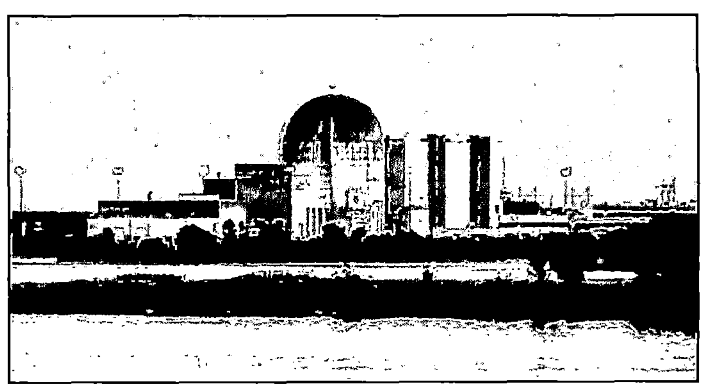


In 2015, KEPCo continued to provide our Members affordable, reliable electric energy from a diverse portfolio of generation resources. KEPCo's current owned and purchase power resources include nuclear, hydroelectric power, coal, natural gas, and wind capacity. KEPCo is also looking forward to adding solar generation in the coming months.

Ever-increasing regulatory oversight and environmental regulations continue to merit substantial attention and concern. In 2015, the Clean Power Plan (CPP) garnered such attention from the electric utility industry, due to the release of the CPP final rule in early August. The carbon dioxide reduction percentage for Kansas in the final rule was quite surprising and disappointing, since it was significantly more stringent than in the June 2014 proposed rule. In addition, the required carbon dioxide reductions from historic levels are substantially more stringent for Kansas when compared to other states.

In response to a motion filed by a majority of the states and many electric utilities, including KEPCo, the U.S. Supreme Court issued an unprecedented stay of the CPP in February of 2016. Prior to the stay of the rule, Kansas electric utilities worked diligently to develop plans and strategies to meet the reduction mandate. Planning will continue while the electric industry awaits the decision of the U. S. District Court, and ultimately the U.S. Supreme Court. The stay of the rule, and subsequent additional time, allows the industry to plan in a more deliberate, efficient manner.

KEPCo does not have an affected generating unit under the CPP rule in Kansas. However, KEPCo does have a 30 megawatt ownership



Wolf Creek Nuclear Generating Station

share of Iatan 2 in Missouri. Iatan 2 is one of the newest, most efficient coal-fired units in the country, thus establishing its per unit of carbon dioxide output at relatively low levels when compared to similar sized plants in the Midwest. Due to the modest coal-based ownership, KEPCo does not anticipate having stranded generating assets due to the CPP. The majority of generation resources that KEPCo relies upon to supply its power, whether through ownership or through purchase power agreements, are carbon-free, including nuclear, hydropower, and wind. These carbon-free resources account for approximately 52% of KEPCo's energy requirements. Given this diverse, low-carbon resource mix, KEPCo will only be economically impacted by the remaining fossil-fuel energy that comes from KEPCo's purchased power resources or from future owned fossil fuel generation. Resource diversity, coupled with KEPCo's limited fossil-fuel ownership exposure, will substantially mitigate the economic impact of CPP compliance to our Member cooperatives, if the rule is ultimately upheld in part or in whole by the courts.

As the utility industry enters into a carbon-constrained environment, whether through the CPP, other carbon reduction regulations, or other political pressures, renewable energy resources, such as solar and wind, will become more important than ever before in the generation resource mix of utilities. Reducing carbon dioxide emissions will likely force utilities to replace and or re-dispatch, in part, fossil fuel generation with renewable energy. In addition, KEPCo's Members have seen interest among their respective memberships regarding the ability to purchase solar energy for use at their homes, farms, and businesses. In consideration of these on-going changes, the KEPCo Board of Trustees, in the fourth quarter of 2015, unanimously approved KEPCo's plan to build a one megawatt solar farm, which will be located on a Member system in Butler County and shared by all KEPCo Member systems.

KEPCo Services, Inc. (KSI) will serve as the project engineer and KEPCo will manage the long-term operations and maintenance of the solar facility. KSI staff performed the feasibility analysis, as well as several other analyses, to determine the viability and optimum location of the facility. The energy produced by the solar farm will be utilized to reduce KEPCo's power needs from traditional resources and will provide carbon-free energy year round to KEPCo's Members. This project further diversifies KEPCo's already varied energy portfolio and enables KEPCo's Members to reap the benefits of solar energy through the economics of a utility-scale project.

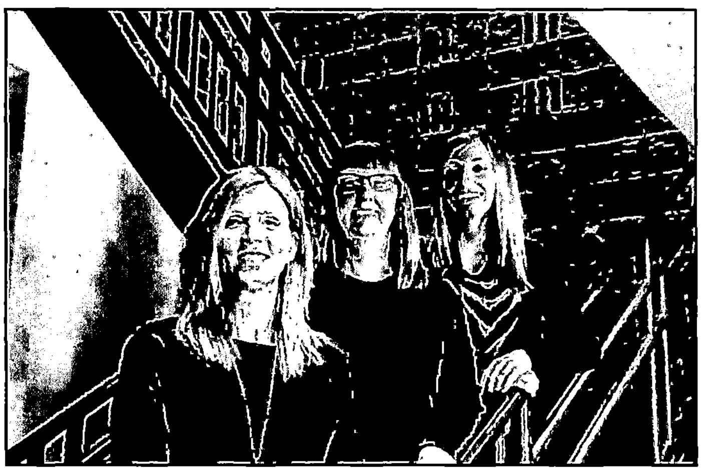

KEPCo Services Inc. (KSI) staff (left to right): Chris Davidson, John Payne, and Mark Barbee

Since KEPCo is a not-for-profit utility that has access to attractive cooperative financing, and since KEPCo will operate and maintain the array itself, the costs associated with the financing, operations and maintenance will be more economical than if KEPCo sought traditional financing and contracted for the operation and maintenance of the facility. These factors will reduce the cost associated with the project for KEPCo's Members.

In the first quarter of 2016, the KEPCo Board

of Trustees unanimously approved a new tariff, M-11B, that more closely aligns KEPCo's cost recovery with the manner in which KEPCo incurs costs. KEPCo solicited the services of Guernsey, a rate consultant, to aid in the analysis and implementation strategy.

KEPCo had a solid financial performance in 2015. KEPCo ended the year with total revenue of $161.7 million and a consolidated net margin of $3.5 million. KEPCo's total assets, including those of its subsidiary, KEPCo Services Incorporated (KSI), were nearly $280 million. The solid financial performance allowed KEPCo to maintain Times Interest Earned and Debt Service Coverage ratios within acceptable levels and enabled KEPCo's equity-to-asset ratio to improve nearly three percent, to 23.9%. KEPCo Members received $3.3 million in patronage capital and $12 million through the Margin Stabilization Adjustment. KEPCo's commitment of keeping rates affordable to its Members is evidenced by 2015 being the fifth consecutive year of not seeking a base rate increase despite many cost pressures that have occurred during this time period.


KEPCo Finance and Accounting staff; (bottom to top) Coleen Wells, Shari Koch, and Stephanie Anderson

Kansas experienced relatively mild weather in 2015, which was reflected in KEPCo's peak demand being virtually identical to the peak demand of 433 MW set in 2014 and energy sales were nearly the same in 2014 as well. The average rate to Members decreased by nearly three mills per kWh, which was influenced by four factors; (1) KEPCo's owned generation producing more energy than in 2014; (2) the amount of available inexpensive hydropower increased substantially; (3) purchased power decreased; (4) lower principal payments associated with KEPCo's Wolf Creek debt as a result of the debt refinancing completed in 2014.

The safety of KEPCo's employees is a point of emphasis each year. KEPCo is proud to announce that 2015 is the fifth consecutive year without a lost time accident. This pattern illustrates the importance of the safety meetings KEPCo conducts not only for KEPCo SCADA Technicians, but administrative personnel as well.

KEPCo's continued success would not be possible without talented employees and a Board of Trustees dedicated to serving and providing KEPCo's Member cooperatives with the knowledge and expertise necessary to operate an electric utility in today's ever-changing environment. The resolve of all those involved with the operation of KEPCo will ensure the continued delivery of safe, reliable, sustainable, and economical energy for rural Kansans.

Marcus Harris
KEPCo EVP & CEO

Scott Whittington
KEPCo President

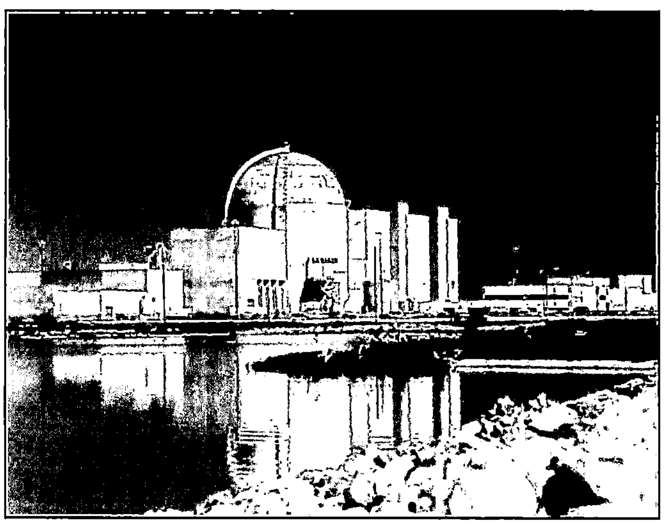
2015 KEPCo Highlights

The Wolf Creek Nuclear Generating Station celebrated its 30th anniversary of operation. Senior staff of Westar Energy, KCP&L, and KEPCo, along with Wolf Creek staff and invited dignitaries, celebrated the historic day. Marcus Harris, KEPCo EVP & CEO recognized the Wolf Creek staff for their hard work and dedication for the 30 years of successful operation of the facility and emphasized the importance of the facility as the industry enters into a carbon-constrained environment.

Marcus Harris provides remarks at the 30th anniversary celebration.

KEPCo began the development of a Long Range Generation Supply Plan (Integrated Resource Plan) to examine the generation resources needed in the future as the utility industry moves to a carbon-constrained environment.

KEPCo staff, along with contractor support, completed member load forecasts for Ark Valley, Butler, DS&O, and Flint Hills electric cooperatives.



Wolf Creek Nuclear Generating Station

Wolf Creek successfully completed refueling outage 20 in the spring and has ran continuously since the refueling. During the outage, Wolf Creek completed a major maintenance project on the Essential Service Water Pipe, which mitigated a water hammer issue.

KEPCo staff analyzed Sunflower Electric Power Corporation's proposed unbundled transmission charge rate for KEPCo under its Wholesale Power Agreement and negotiated with Sunflower to agree to a formula-based calculation of the monthly transmission charge rate, instead of the proposed stated rate, which resulted in a notable savings to KEPCo from April 2014 through October 2015.

For 18 years, KSI has provided valuable engineering services for KEPCo Members while covering its expenses and contributing to KEPCo overheads. In 2015, KSI generated $292,500 in gross revenue, contributed $43,600 towards KEPCo overheads and produced a net margin of $27,000. These revenues were the product of KSI's involvement with 71 projects for 14 KEPCo Members, two non-members and Kansas Electric Cooperatives (KEC). These projects included construction work plans, work order inspections, arc hazard assessment updates, spill prevention control and counter measures plan updates, load studies, and map updates.

Kansas Legislative Bus Tour
Southwest Power Pool
Little Rock, Arkansas
November 4-5, 2015

Phil Wages, KEPCo, and staff of Westar Energy and Sunflower Electric discuss energy issues with Senator Pat Roberts' staff during the SPP Washington, D.C. trip.

KEPCo staff participated in two Southwest Power Pool (SPP) legislative events. The first was a two-day visit to Washington, D.C. to discuss with several members of Congress, two FERC Commissioners, and an EPA staff member federal energy legislation, as well as the Clean Power Plan final rule. The second event was a bus trip for Kansas legislators to the SPP headquarters in Little Rock, AR to learn about the responsibilities and operations of the SPP, and to discuss the SPP's role in compliance with the Clean Power Plan.

Kansas Electric Cooperatives (KEC) and MarksNelson, a CPA and business advisement firm, successfully appealed to the Kansas Board of Tax Appeals the increase in the capitalization rate (discount rate) used to establish the amount of property tax owed by KEPCo. The successful appeal resulted in a considerable refund to KEPCo.

USDA Rural Development

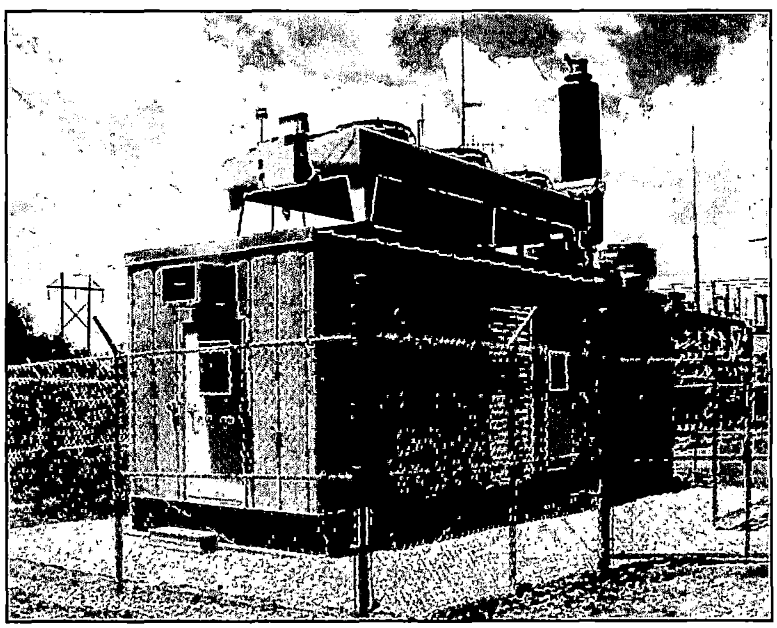
Committed to the future of rural communities.

KEPCo continues to work with its Member cooperatives in an aggressive rural development program that has successfully created rural jobs and wealth retention in Kansas. The USDA Rural Economic Development Loan & Grant (REDLG) program provides zero interest loans to worthy projects.

KEPCo staff worked with Westar Energy on an update to the Wholesale Distribution Service Charge (WDSC) that KEPCo pays for the use of Westar Energy distribution facilities (< 34.5 kV). This monthly charge is based on KEPCo's share of the load on the distribution assets used to provide this service, the depreciated value of these assets and a FERC approved carrying charge. The new WDSC, effective August 1, 2015, is a significant cost reduction for KEPCo.

KEPCo developed enhanced coordination of KEPCo member distributed generation for improved demand response during the summer peak demand months.

KEPCo staff completed the necessary coordination for approval and installation of five new delivery points. In addition, staff continued to monitor the service reliability for each of the KEPCo delivery points and to work closely with Westar Energy, and other transmission providers, to address any reliability concerns.



Butler Rural Electric Cooperative demand response generator

Safety of our employees is essential to the continued operational success of KEPCo. Several safety meetings are conducted throughout the year for KEPCo's SCADA Technicians and administrative personnel. KEPCo is proud to report there were no lost time accidents recorded in 2015.

KEPCo Member Cooperatives
Trustees, Alternates and Managers


Joseph Seiwert

Ark Valley Electric Cooperative Assn., Inc.
PO Box 1246, Hutchinson, KS 67504
620-662-6661
Trustee Rep. -- Joseph Seiwert
Alternate Trustee -- Jackie Holmberg
Manager -- Jackie Holmberg


Jackie Holmberg


Ken Maginley

Bluestem Electric Cooperative, Inc.
PO Box 5, Wamego, KS 66547 785-456-2212
PO Box 513, Clay Center, KS 67432 785-632-3111
Trustee Rep. -- Kenneth J. Maginley
Alternate Trustee -- Robert Ohlde
Manager -- Kenneth J. Maginley


Bob Ohlde


Kevin Compton

Brown-Atchison Electric Cooperative, Assn., Inc.
PO Box 230, Horton, KS 66439 785-486-2117
Trustee Rep. -- Kevin Compton
Alternate Trustee -- James Currie
Manager -- James Currie


Jim Currie

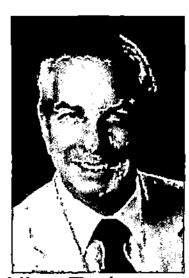

Dale Short

Butler Rural Electric Cooperative Assn., Inc.
PO Box 1242, El Dorado, KS 67402 316-321-9600
Trustee Rep. -- Dale Short
Alternate Trustee -- Riley Walters
Manager -- Dale Short


Riley Walters

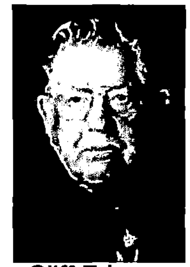

Dwane Kessinger

Caney Valley Electric Cooperative Assn., Inc.
PO Box 308, Cedar Vale, KS 67204 620-758-2262
Trustee Rep. -- Dwane Kessinger
Alternate Trustee -- Allen A. Zadorozny
Manager -- Allen A. Zadorozny


Allen Zadorozny


Kirk Thompson

CMS Electric Cooperative, Inc.
PO Box 790, Meade, KS 67864   620-873-2184
Trustee Rep. -- Kirk A. Thompson
Alternate Trustee -- Clifford Friesen
Manager -- Kirk A. Thompson


Cliff Friesen


Dean Allison

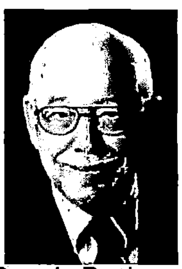
DS&O Electric Cooperative, Inc.
PO Box 286, Solomon, KS 67480   785-655-2011
Trustee Rep. -- Dean Allison
Alternate Trustee -- Tim Power
Manager -- Tim Power


Tim Power


Bob Reece

Flint Hills Electric Cooperative Assn., Inc.
PO Box B, Council Grove, KS 66846   620-767-5144
Trustee Rep. -- Robert E. Reece
Alternate Trustee -- William Hein
Manager -- Robert E. Reece


William Hein


Dennis Peckman

Heartland Rural Electric Cooperative, Inc.
PO Box 40, Girard, KS 66743   620-724-8251
Trustee Rep. -- Dennis Peckman
Alternate Trustee -- Dale Coomes
Manager -- Dale Coomes


Dale Coomes


Larry Stevens

LJEC
PO Box 70, McLouth, KS 66054   913-796-6111
Trustee Rep. -- Larry Stevens
Alternate Trustee -- Steven O. Foss
Manager -- Steven O. Foss


Steven Foss


Scott Whittington

Lyon-Coffey Electric Cooperative, Inc.
PO Box 229, Burlington, KS 66839   620-364-2116
Trustee Rep. -- Scott Whittington
Alternate Trustee -- Donna Williams
Manager -- Scott Whittington


Donna Williams

KEPCo Member Cooperatives
Trustees, Alternates and Managers


Paul Unruh

Ninnescah Electric Cooperative Assn., Inc.
PO Box 967, Pratt, KS 67124   620-672-5538
Trustee Rep. -- Paul Unruh
Alternate Trustee -- Teresa Miller
Manager -- Teresa Miller


Teresa Miller


Gilbert Berland

Prairie Land Electric Cooperative, Inc.
PO Box 360, Norton, KS 67654   785-877-3323
District Office, Bird City 785-734-2311
District Office, Concordia 785-243-1750
Trustee Rep. -- Gilbert Berland
Alternate Trustee -- Allan J. Miller
Manager -- Allan J. Miller


Allan Miller


Dennis Duft

Radiant Electric Cooperative, Inc.
PO Box 390, Fredonia, KS 66736   620-378-2161
Trustee Rep. -- Dennis Duft
Alternate Trustee -- Tom Ayers
Administrative Manager -- Leah Tindle
Operations Manager -- Dennis Duft


Tom Ayers


Leah Tindle


Doug Jackson

Rolling Hills Electric Cooperative, Inc.
PO Box 307, Mankato, KS 66956   785-378-3151
District Offices, Belleville 785-527-2251
Ellsworth 785-472-4021
Trustee Rep. -- Douglas J. Jackson
Alternate Trustee -- Leon Eck
Manager -- Douglas J. Jackson


Leon Eck


Donald Metzen

Sedgwick County Electric Cooperative Assn., Inc.
PO Box 220, Cheney, Ks 67025   316-542-3131
Trustee Rep. -- Donald Metzen
Alternate Trustee -- David Childers
Manager -- David Childers


Dave Childers

John Schon

Sumner-Cowley Electric Cooperative, Inc.
PO Box 220, Wellington, KS 67152 620-326-3356
Trustee Rep. -- John Schon
Alternate Trustee -- Cletas Rains
Manager -- Cletas Rains

Cletas Rains

Bryan Coover

Twin Valley Electric Cooperative, Inc.
PO Box 368, Altamont, KS 67330 620-784-5500
Trustee Rep. -- Bryan Coover
Alternate Trustee -- Ron Holsteen
Manager -- Ron Holsteen

Ron Holsteen

Shane Laws

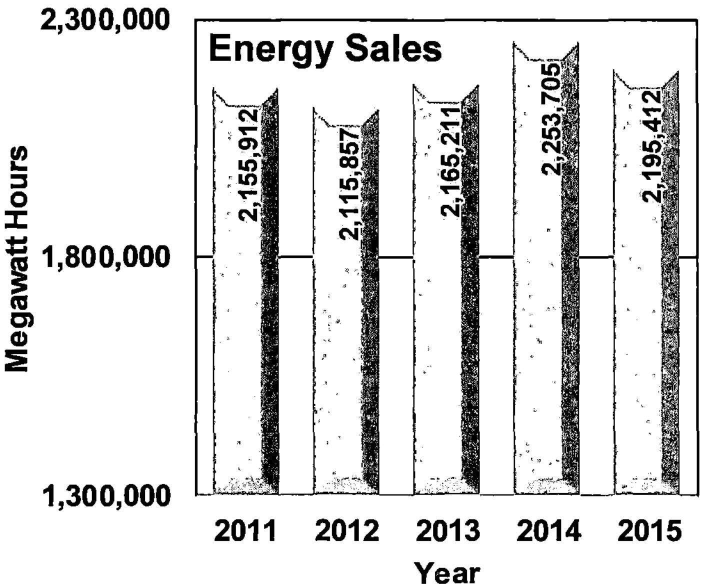
Victory Electric Cooperative Assn., Inc.
PO Box 1335, Dodge City, KS 67801 620-227-2139
Trustee Rep. -- Shane Laws
Alternate Trustee -- Daryl Tieben
Manager -- Shane Laws

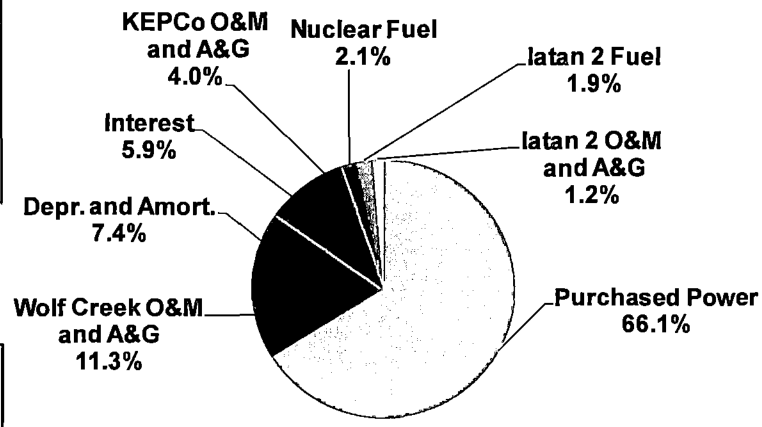
Daryl Tieben

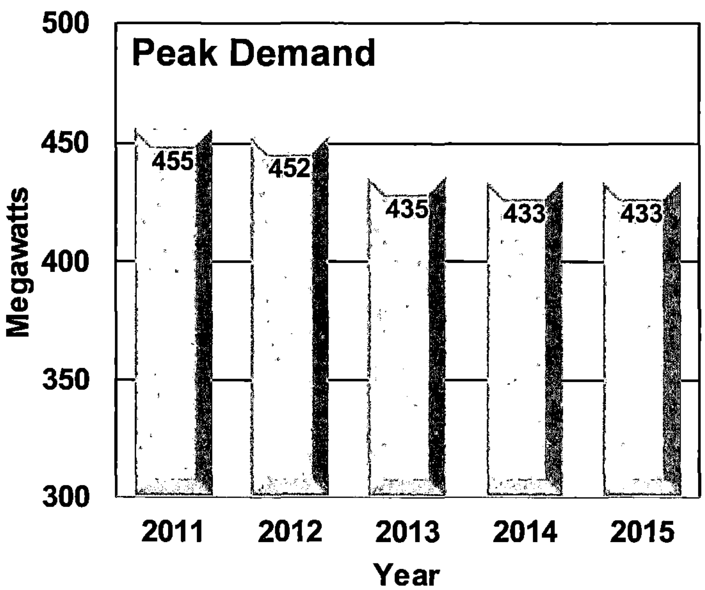
2015 - 2016 KEPCo Executive Committee

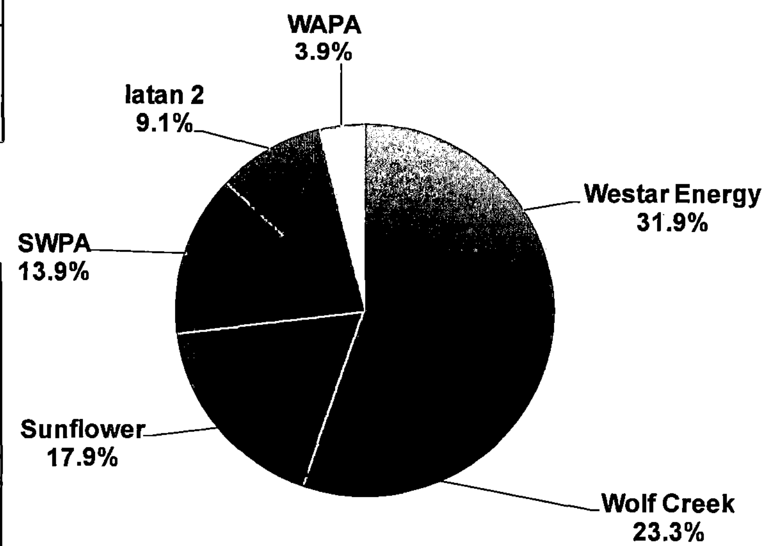
Back row, left to right: Dean Allison - Secretary; Kevin Compton - Vice President; Scott Whittington - President; Dale Short - Treasurer. Front row, left to right; Bryan Coover - Executive Committee; Larry Stevens - Executive Committee.; Dwane Kessinger—Executive Committee.

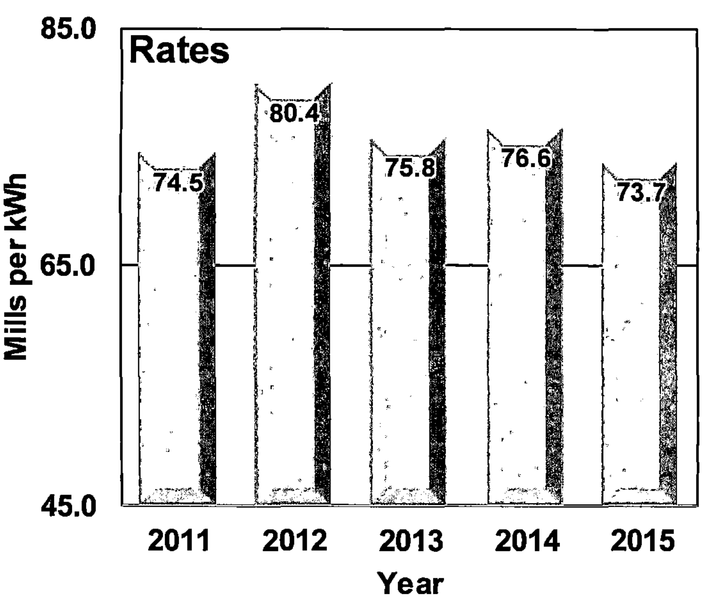
Operating Statistics











INDEPENDENT AUDITORS' REPORT

To the Board of Directors
Kansas Electric Power Cooperative, Inc.
Topeka, Kansas

We have audited the accompanying consolidated financial statements of Kansas Electric Power Cooperative, Inc. and subsidiary ("KEPCo"), which comprise the consolidated balance sheets as of December 31, 2015 and 2014, and the related consolidated statements of margin, patronage capital, and cash flows for the years then ended and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and *Government Auditing Standards,* issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our qualified audit opinion.

Basis for Qualified Opinion

As more fully described in Note 3 to the financial statements, certain depreciation and amortization methods have been used in the preparation of the 2015 and 2014 consolidated financial statements which, in our opinion, are not in accordance with accounting principles generally accepted in the United States of America. The effects on the consolidated financial statements of the aforementioned departure are explained in Note 3.

Qualified Opinion

In our opinion, except for the effects of using the aforementioned depreciation and amortization methods as discussed in Note 3, the consolidated financial statements referred to in the first paragraph present fairly, in all material respects, the financial position of KEPCo as of December 31, 2015 and 2014, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Reporting Required by Government Auditing Standards

In accordance with *Government Auditing Standards*, we also have issued our report dated April 6, 2016, on our consideration of KEPCo's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering KEPCo's internal control over financial reporting and compliance.

Mayer Hoffman McCann P.C.

Mayer Hoffman McCann P.C.
Topeka, Kansas
April 6, 2016

Consolidated Balance Sheets

Assets	December 31, 2015	December 31, 2014
Utility Plant		
In-service	$ 352,889,719	$ 340,615,798
Less allowances for depreciation	(155,634,830)	(148,469,211)
Net in-service	197,254,889	192,146,587
Construction work in progress	9,970,255	9,776,657
Nuclear fuel (less accumulated amortization of $23,765,663 and $23,151,678 for 2015 and 2014, respectively)	8,459,672	9,809,670
Total utility plant	215,684,816	211,732,914
Restricted Assets		
Investments in the National Utilities Cooperative Finance Corporation	11,108,619	11,741,745
Bond fund reserve	-	4,490,786
Decommissioning fund	19,996,196	19,378,279
Investments in other associated organizations	282,188	264,976
Total restricted assets	31,387,003	35,875,786
Current Assets		
Cash and cash equivalents	6,307,421	1,202,643
Member account receivables	11,993,431	14,041,772
Materials and supplies inventory	6,645,359	6,391,899
Other assets and prepaid expenses	705,652	699,236
Total current assets	25,651,863	22,335,550
Other Long-term Assets		
Deferred charges		
Wolf Creek disallowed costs (less accumulated amortization of $17,935,208 and $17,178,044 for 2015 and 2014, respectively)	8,047,713	8,804,877
Wolf Creek deferred plants costs (less accumulated amortization of $43,818,873 and $40,688,954 for 2015 and 2014, respectively)	3,129,920	6,259,839
Wolf Creek decommissioning regulatory asset	(6,624,525)	(7,217,629)
Deferred incremental outage costs	1,968,169	1,185,502
Other deferred charges (less accumulated amortization of $9,681,046 and $9,515,076 for 2015 and 2014, respectively)	359,142	391,103
Unamortized debt issuance costs	23,713	80,055
Other	270,943	247,538
Prepaid pension cost	941,896	1,073,323
Total long-term assets	8,116,971	10,824,608
Total assets	$ 280,840,653	$ 280,768,858

See Notes to the Consolidated Financial Statements

Consolidated Balance Sheets

Liabilities and Patronage Capital	December 31, 2015	December 31, 2014
Patronage Capital		
Memberships	$ 3,200	$ 3,200
Patronage capital	76,798,889	73,517,749
Accumulated other comprehensive loss	(7,284,730)	(8,379,226)
Total patronage capital	69,517,359	65,141,723
Long-term Debt	147,216,732	152,126,943
Other Long-term Liabilities		
Wolf Creek decommissioning liability	18,314,245	13,320,625
Wolf Creek pension and postretirement benefit plans	11,824,521	12,004,519
Wolf Creek deferred compensation	1,249,381	1,314,323
Total other long-term liabilities	31,388,147	26,639,467
Current Liabilities		
Current maturities of long-term debt	11,456,396	15,683,929
Accounts payable	13,053,258	14,199,898
Payroll and payroll-related liabilities	241,353	257,523
Short term note payable	-	1,429,000
Deferred revenue	6,104,206	3,325,322
Accrued property taxes	1,312,387	1,371,811
Accrued income taxes	(45)	3,518
Accrued interest payable	550,860	589,724
Total current liabilities	32,718,415	36,860,725
Total patronage capital and liabilities	$ 280,840,653	$ 280,768,858

See Notes to the Consolidated Financial Statements

Consolidated Statements of Margin

	For the years ending December 31, 2015	2014
Operating Revenues		
Sale of electric energy	$ 161,763,501	$ 172,576,128
Operating Expenses		
Power purchased	105,484,032	116,339,132
Nuclear fuel	3,368,666	3,402,688
Plant operations	17,340,438	16,231,337
Plant maintenance	5,406,848	6,647,651
Administrative and general	6,205,902	6,284,806
Amortization of deferred charges	4,053,051	4,122,663
Depreciation and decommissioning	8,480,727	7,444,553
Total operating expenses	150,339,664	160,472,830
Net operating revenues	11,423,837	12,103,298
Interest and Other Deductions		
Interest on long-term debt	9,090,142	9,415,650
Amortization of debt issuance costs	56,343	67,609
Other deductions	150,753	407,649
Total interest and other deductions	9,297,238	9,890,908
Operating income	2,126,599	2,212,390
Other Income/(Expense)		
Interest income	667,857	915,409
Other income	488,538	370,401
Income tax	(1,854)	(5,768)
Total other income	1,154,541	1,280,042
Net margin	$ 3,281,140	$ 3,492,432
Net Margin	$ 3,281,140	$ 3,492,432
Other comprehensive (loss)/income		
Net earnings/(loss) arising during year on pension obligation	329,818	(4,717,230)
Amortization of prior year service costs included in net periodic pension costs	764,678	409,785
Comprehensive income/(loss)	$ 4,375,636	$ (815,013)

See Notes to the Consolidated Financial Statements

Consolidated Statements of Patronage Capital

	Memberships	Patronage Capital	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2013	$ 3,200	$ 70,025,317	$ (4,071,781)	$ 65,956,736
Net margin	-	3,492,432	-	3,492,432
Defined benefit pension plans:				
Net loss arising during year	-	-	(4,717,230)	(4,717,230)
Amortization of prior year service costs included in net periodic pension costs	-	-	409,785	409,785
Balance at December 31, 2014	3,200	73,517,749	(8,379,226)	65,141,723
Net margin	-	3,281,140	-	3,281,140
Defined benefit pension plans:				
Net earnings arising during year	-	-	329,818	329,818
Amortization of prior year service costs included in net periodic pension costs	-	-	764,678	764,678
Balance at December 31, 2015	$ 3,200	$ 76,798,889	$ (7,284,730)	$ 69,517,359

See Notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

	For the years ending December 31, 2015	2014
Cash Flows From Operating Activities		
Net margin	$ 3,281,140	$ 3,492,432
Adjustments to reconcile net margin to net cash flows from operating activities		
Depreciation and amortization	7,976,377	7,028,254
Decommissioning	4,400,516	1,495,700
Amortization of nuclear fuel	3,330,466	3,240,394
Amortization of deferred charges	3,901,324	4,122,662
Amortization or deferred incremental outage costs	2,387,697	5,668,059
Amortization of debt issuance costs	56,342	67,609
Changes in		
Member accounts receivable	2,048,341	(8,376,832)
Materials and supplies	(253,460)	(635,064)
Other assets and prepaid expense	(6,416)	35,701
Accounts payable	(1,146,640)	(323,319)
Payroll and payroll-related liabilities	(16,170)	14,479
Accrued property tax	(59,425)	(148,104)
Accrued interest payable	(38,864)	(45,341)
Accrued income taxes	(3,564)	3,518
Other long-term liabilities	826,151	445,958
Prepaid pension cost	131,428	472,371
Deferred revenue	2,778,884	2,100,898
Net cash flows from operating activities	29,594,127	18,659,375
Cash Flows From Investing Activities		
Additions to electrical plant	(13,317,627)	(15,556,312)
Additions to nuclear fuel	(1,980,468)	(5,243,757)
Reductions in deferred charges	17,720	174,656
Additions to deferred incremental outage costs	(3,170,364)	(594,202)
Investments in decommissioning fund assets	(617,917)	(1,533,935)
Proceeds from associated organizations	615,915	339,892
Investments in bond reserve assets	4,490,786	(24,918)
Proceeds from the sale of property	39,350	14,402
Net cash flows from investing activities	(13,922,605)	(22,424,174)
Cash Flows From Financing Activities		
Principal payments on long-term debt	(15,700,763)	(19,429,155)
Proceeds from issuance of long-term debt	9,887,110	25,993,166
Short term notes payable	(1,429,000)	(5,071,000)
Payments unapplied	(3,324,091)	(1,707,113)
Net cash flows from financing activities	(10,566,744)	(214,102)
Net increase (decrease) in cash and cash equivalents	5,104,778	(3,978,901)
Cash and Cash Equivalents, Beginning of Year	1,202,643	5,181,544
Cash and Cash Equivalents, End of Year	$ 6,307,421	$ 1,202,643
Supplemental Disclosure of Cash Flow Information		
Interest paid	$ 9,279,800	$ 9,868,600

See Notes to the Consolidated Financial Statements

Notes to Consolidated Financial Statements

(1) Nature of Operations and Summary of Significant Accounting Policies

Nature of Operations - Kansas Electric Power Cooperative, Inc., and its subsidiary KEPCo Services, Inc. (KEPCo), headquartered in Topeka, Kansas, was incorporated in 1975 as a not-for-profit generation and transmission cooperative (G&T). KEPCo was granted a limited certificate of convenience and authority by the Kansas Corporation Commission (KCC) in 1980 to act as a G&T public utility. It is KEPCo's responsibility to procure an adequate and reliable power supply for its 19 distribution rural electric cooperative members pursuant to all requirements of its power supply contracts. KEPCo is governed by a board of trustees representing each of its 19 members, which collectively serve approximately 120,000 electric meters in rural Kansas. KEPCo Services, Inc. is an engineering consulting firm who specializes in consulting projects for other local electric cooperatives.

System of Accounts - KEPCo maintains its accounting records substantially in accordance with the Rural Utilities Service (RUS) Uniform Systems of Accounts and in accordance with accounting practices prescribed by the KCC.

Rates - Under a 2009 change in Kansas state law, KEPCo has elected to be exempt from KCC regulation for most purposes, including the setting of rates. Rates are set by action of the Board, subject only to statutory review by the KCC if demanded by four or more members. KEPCo's rates were last set by the KCC by an order effective September 1, 2008. KEPCo's rates now include an Energy Cost Adjustment (ECA) mechanism, an annual Demand Cost Adjustment (DCA) mechanism and a Margin Stabilization Adjustment (MSA) mechanism, allowing KEPCo to pass along increases in certain energy and demand costs to its member cooperatives.

Principles of Consolidation - The consolidated financial statements include the accounts of KEPCo and its wholly owned subsidiary, KEPCo Services, Inc. Undivided interests in Wolf Creek Nuclear Operating Corporation and Iatan 2 generation facilities are consolidated on a pro rata basis. All material intercompany accounts and transactions have been eliminated in consolidation.

Estimates - The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Management's estimates and assumptions include, but are not limited to, estimates of salvage values, estimated useful lives of fixed assets and estimated asset retirement obligations. Management's estimates and assumptions are derived from and are continually evaluated based upon available information, judgement and experience.

Utility Plant and Depreciation - Utility plant is stated at cost. Cost and additions to utility plant include contractual work, direct labor, materials and interest on funds used during construction. No interest has been capitalized in 2015 and 2014. The cost of repairs and minor replacements are charged to operating expenses as appropriate. The original cost of utility plant retired and the cost of removal less salvage are charged to accumulated depreciation.

The composite depreciation rates for electric generation plant for the years ended December 31, 2015 and 2014 are 3.76% and 3.59%, respectively.

The provision for depreciation computed on a straight-line basis for electric and other components of utility plant is as follows:

Transportation and equipment	25-33 years
Office furniture and fixtures	10-20 years
Leasehold improvements	20 years
Transmission equipment (metering, communication and SCADA)	10 years

Notes to Consolidated Financial Statements

Iatan 2 - Iatan 2 is an 850 MW high efficiency coal-fired power plant utilizing state-of-the-art environmental controls that became commercially operational December 31, 2010. KEPCo owns a 3.53% share of Iatan 2, or 30 MW. Iatan 2, located in Weston, MO, is operated and majority owned by KCP&L.

Wolf Creek Nuclear Operating Corporation - KEPCo owns 6% of Wolf Creek Nuclear Operating Corporation (WCNOC), which is located near Burlington, Kansas. The remainder is owned by the Kansas City Power & Light Company (KCPL) 47% and Kansas Gas & Electric Company (KGE) 47%. KGE is a wholly owned subsidiary of Westar Energy, Inc. KCPL is a wholly owned subsidiary of Great Plains Energy, Inc. KEPCo's undivided interest in WCNOC is consolidated in the financial statements on a pro rata basis. KEPCo is entitled to a proportionate share of the capacity and energy from WCNOC, which is used to supplement a portion of KEPCo's members' requirements. KEPCo is billed on a daily basis for 6% of the operations, maintenance, administrative and general costs, and cost of plant additions related to WCNOC.

WCNOC's operating license expires in 2045. Wolf Creek is regulated by the nuclear Regulatory Commission (NRC), with respect to licensing, operations and safety related requirements.

WCNOC disposes of all classes of its low-level radioactive waste at existing third-party repositories. Should disposal capability become unavailable, WCNOC is able to store its low-level radioactive waste in an on-site facility for up to three years under current regulations.

Nuclear Fuel - The cost of nuclear fuel in the process of refinement, conversion, enrichment and fabrication is recorded as a utility plant asset at original cost and is amortized to nuclear fuel expenses based upon the quantity of heat produced for the generation of electric power. Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek paid into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. In November 2013, a federal court of appeals ruled that the DOE must stop collecting this fee effective May 2014. KEPCo's share of the fee, calculated as one tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers, was $0 and $104,499 in 2015 and 2014, respectively. KEPCo included these costs in fuel and purchased power expense on the consolidated statements of margin.

Nuclear Decommissioning - Nuclear decommissioning is a nuclear industry term for the permanent shutdown of a nuclear power plant and the removal of radioactive components in accordance with Nuclear Regulatory Commission (NRC) requirements. The NRC will terminate a plant's license and release the property for unrestricted use when a company has reduced the residual radioactivity of a nuclear plant to a level mandated by the NRC. The NRC requires companies with nuclear plants to prepare formal financial plans to fund nuclear decommissioning. These plans are designed so that sufficient funds required for nuclear decommissioning will be accumulated prior to the expiration of the license of the related nuclear power plant. Wolf Creek files a nuclear decommissioning site study with the KCC every three years.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the revised nuclear decommissioning study including the estimated costs to decommission the plant. Phase two involves the review and approval of a funding schedule prepared by the owner of the plant detailing how it plans to fund the future-year dollar amount of its pro rata share of the decommissioning costs.

In 2014, the nuclear decommissioning study was revised. Based on the study, KEPCo's share of decommissioning costs, including decontamination, dismantling and site restoration, is estimated to be $45.9 million. This amount compares to the prior site study estimate of $37.8 million. The site study cost estimate represents the estimate to decommission Wolf Creek as of the site study year. The actual nuclear decommissioning costs may vary from the estimates because of changes in regulations and technologies as well as changes in costs for labor, materials, and equipment.

Notes to Consolidated Financial Statements

KEPCo is allowed to recover nuclear decommissioning costs in its prices over a period equal to the operating license of Wolf Creek, which is through 2045. The NRC requires that funds sufficient to meet nuclear decommissioning obligations be held in a trust. KEPCo believes that the KCC approved funding level will also be sufficient to meet the NRC requirement. The consolidated financial results would be materially affected if KEPCo was not allowed to recover in its prices the full amount of the funding requirement.

KEPCo recovered in its prices and deposited in an external trust fund for nuclear decommissioning approximately $0.5 million in 2015 and $0.5 million in 2014. KEPCo records its investment in the Nuclear Decommissioning Trust fund at fair value, which approximated $20.0 million and $19.4 million as of December 31, 2015 and 2014, respectively.

Asset retirement obligation - KEPCo recognizes and estimates the legal obligation associated with the cost to decommission Wolf Creek. KEPCo initially recognized an asset retirement obligation at fair value for the estimated cost with a corresponding amount capitalized as part of the cost of the related long-lived asset and depreciated over the useful life.

A reconciliation of the asset retirement obligation for the years ended December 31, 2015 and 2014 is as follows:

	2015	2014
Balance at January 1	$ 13,320,625	$ 12,542,673
2014 decommission study	3,952,587	-
Accretion	1,041,033	777,952
Balance at December 31	$ 18,314,245	$ 13,320,625

Any net margin effects are deferred in the Wolf Creek decommissioning regulatory asset and will be collected from members in future electric rates.

Cash and Cash Equivalents - All highly liquid investments purchased with an original maturity of three months or less are considered to be cash equivalents and are stated at cost, which approximates fair value. Cash equivalents consisted primarily of repurchase agreements, money market accounts and certificates of deposit.

The Federal Deposit Insurance Corporation insures amounts held by each institution in the organization's name up to $250,000. At various times during the fiscal year, the organization's cash in bank balances exceeded the federally insured limits.

KEPCo's repurchase agreements have collateral pledged by a financial institution, which are securities that are backed by the federal government.

Accounts Receivable - Accounts receivable are stated at the amount billed to members and customers. KEPCo provides allowances for doubtful accounts, which is based upon a review of outstanding receivables, historical collection information and existing economic conditions.

Materials and Supplies Inventory - Materials and supplies inventory are valued at average cost.

Unamortized Debt Issuance Costs - Unamortized debt issue costs relate to the issuance of the floating/fixed rate pollution control revenue bonds, mortgage notes payable to the National Rural Utilities Cooperative Finance Corporation (CFC) trusts and fees for re-pricing the Federal Financing Bank (FFB) debt. These costs are being amortized using the effective interest method over the remaining life of the bonds and notes.

Notes to Consolidated Financial Statements

Cash Surrender Value of Life Insurance Contracts - The following amounts related to Wolf Creek Nuclear Operating Corporation (WCNOC) corporate-owned life insurance contracts, primarily with one highly rated major insurance company, are included in other long-term assets on the consolidated balance sheets.

	2015	2014
Cash surrender value of contracts	$ 7,423,520	$ 7,169,654
Borrrowings against contracts	(7,167,492)	(6,922,116)
	$ 256,028	$ 247,538

Borrowings against contracts include a prepaid interest charge. KEPCo pays interest on these borrowings at a rate of 5.00% for the years ended December 31, 2015 and 2014.

Revenues - Revenues are recognized during the month the electricity is sold. Revenues from the sale of electricity are recorded based on usage by member cooperatives and customers and on contracts and scheduled power usages as appropriate.

Income Taxes - As a tax-exempt cooperative, KEPCo is exempt from income taxes under Section 501 (c)(12) of the Internal Revenue Code of 1986, as amended. Accordingly, provisions for income taxes have not been reflected in the accompanying consolidated financial statements. KEPCo is no longer subject to federal or state income tax examinations by taxing authorities for years prior to 2012.

KEPCo Services, Inc., a subsidiary of Kansas Electric Power Cooperative, Inc., is not exempt from income taxes. The organization's present accounting policy for the evaluation of uncertain tax positions is to review those positions on an annual basis. A liability would be recorded in the financial statements during the period which, based on all available evidence, management believes it is more likely than not that the tax position would not be sustained upon examination by taxing authorities and the liability would be incurred by the organization.

(2) Factors That Could Affect Future Operating Results

KEPCo currently applies accounting standards that recognize the economic effects of rate regulation and, accordingly, has recorded regulatory assets and liabilities related to its generation and transmission operations in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980, *Regulated Operations*. In the event KEPCo determines that it no longer meets the criteria of ASC 980, the accounting impact could be a noncash charge to operations of an amount that would be material. Criteria that could give rise to the discontinuance of ASC 980 include: 1) increasing competition that restricts KEPCo's ability to establish prices to recover specific costs and 2) a significant change in the manner in which rates are set by regulators from a cost-based regulation to another form of regulation. KEPCo periodically reviews these criteria to ensure the continuing application of ASC 980 is appropriate. Any changes that would require KEPCo to discontinue the application of ASC 980 due to increased competition, regulatory changes or other events may significantly impact the valuation of KEPCo's investment in utility plant, its investment in Wolf Creek and necessitate the write-off of regulatory assets. At this time, the effect of competition and the amount of regulatory assets that could be recovered in such an environment cannot be predicted.

The 1992 Energy Policy Act began the process of restructuring the United States electric utility industry by permitting the Federal Energy Regulatory Commission to order electric utilities to allow third parties to sell electric power to wholesale customers over their transmission systems. KEPCo has elected to deregulate its rate making for sales to its members under recent statutory amendments.

Subject to the possibility of KCC review, KEPCo's member rates are now set by action of the Board. KEPCo's ability to timely recover its costs is enhanced by this change.

Notes to Consolidated Financial Statements

(3) Departures From Generally Accepted Accounting Principles

Wolf Creek Deferred Plant Costs - Effective February 1, 1987, the KCC issued an order to KEPCo requiring the use of present worth (sinking fund) depreciation and amortization. Such depreciation and amortization methods constituted phase-in plans that did not meet the requirements of ASC 980-340 *Regulated Operation, Other Assets and Deferred Costs.*

Effective February 1, 2002, the KCC issued an order that extended the depreciable life of Wolf Creek from 40 years to 60 years. This order also permitted recovery in rates of the $53.5 million cumulative difference between historical present worth (sinking fund) depreciation and amortization and straight-line depreciation and amortization of the Wolf Creek generation plant and disallowed costs over a 15-year period. Recovery of these costs in rates is included in operating revenues, and the related amortization expense is included in deferred charges in the consolidated statements of margin.

The effect of these departures from accounting principles generally accepted in the United States of America is to overstate (understate) the following items in the consolidated financial statements by the following amounts:

	2015	2014
Deferred charges	$ 3,563,634	$ 7,127,268
Patronage capital	$ 3,563,634	$ 7,127,268
Net margin	$ (3,563,634)	$ (3,563,634)

Effective February 1, 2002, the KCC issued an order permitting recovery in rates of the $46.9 million cumulative difference between historical present worth (sinking fund) depreciation and straight-line depreciation of Wolf Creek generation plant over a 15-year period. Such depreciation practice does not constitute a phase-in plan that meets the requirements of ASC 980-340. In 2002, this cumulative difference was reclassified from utility plant allowance for depreciation to deferred charges on the consolidated balance sheets to reflect the amount as a regulatory asset.

Amortization of the Wolf Creek deferred plant costs is included in amortization of deferred charges and amounts to $3.1 million for each of the years ended December 31, 2015 and 2014.

If the deferred plant costs were recovered using a method in accordance with accounting principles generally accepted in the United States of America, the costs would have been expensed in their entirety upon implementation of the KCC order, with a corresponding decrease in patronage capital.

Wolf Creek Disallowed Costs - Effective October 1, 1985, the KCC issued a rate order relating to KEPCo's investment in Wolf Creek, which disallowed $26.0 million of KEPCo's investment in Wolf Creek ($8.0 million net of accumulated amortization as of December 31, 2015). A subsequent rate order, effective February 1, 1987, allows KEPCo to recover these disallowed costs and other costs related to the disallowed portion (recorded as deferred charges) for the period from September 3, 1985 through January 31, 1987, over a 27.736-year period starting February 1, 1987. Pursuant to a KCC rate order dated December 30, 1998, the disallowed portion's recovery period was extended to a 30-year period. Through December 31, 2001, KEPCo used the present worth (sinking fund) method to recover the disallowed costs, which enabled it to meet the times-interest-earned ratio and debt service requirements in the KCC rate order dated January 30, 1987. The method used by KEPCo through 2001 constituted a phase-in plan that did not meet the requirements of *ASC 980- 340, Regulated Operations, Other Assets and Deferred Costs.*

Effective February 1, 2002, the KCC issued an order permitting recovery in rates of the $6.5 million cumulative difference between historical present worth (sinking fund) and straight-line amortization of Wolf Creek disallowed costs over a 15-year period. Such depreciation practice does not constitute a phase-in plan that meets the requirements of ASC 980-340.

If the disallowed costs were recovered using a method in accordance with U.S. generally accepted accounting principles, the costs would have been expensed in their entirety upon implementation of the KCC order, with a corresponding decrease in patronage capital.

Amortization of the Wolf Creek disallowed costs is included in amortization of disallowed charges and amounts to $0.8 million for each of the years ended December 31, 2015, and 2014.

(4) Investments in Associated Organizations

Investments in associated organizations are carried at cost. At December 31, 2015 and 2014, investments in associated organizations consisted of the following:

	2015	2014
Cooperative Financial Corporation		
Memberships	$ 1,000	$ 1,000
Capital term certificates	395,970	395,970
Patronage capital certificates	1,575,231	1,317,279
Equity term certificates	9,136,418	10,027,496
	11,108,619	11,741,745
Other	282,188	264,976
	$ 11,390,807	$ 12,006,721

(5) Deferred Charges

Deferred Incremental Outage Costs - In 1991, the KCC issued an order that allowed KEPCo to defer its 6% share of the incremental operating, maintenance and replacement power costs associated with the periodic refueling of Wolf Creek. Such costs are deferred during each refueling outage and are being amortized over the approximate 18-month operating cycle coinciding with the recognition of the related revenues. Additions to the deferred incremental outage costs were $3.2 million and $0.6 million in 2015 and 2014, respectively. The current year amortization of the deferred incremental outage costs was $2.4 million and $5.7 million in 2015 and 2014, respectively.

Other Deferred Charges - KEPCo includes in other deferred charges the early call premium resulting from refinancing. These early call premiums are amortized using the effective interest method over the remaining life of the new agreements.

Notes to Consolidated Financial Statements

(6) Line of Credit

As of December 31, 2015, KEPCo has a $20 million line of credit available with the Cooperative Finance Corporation. There were no funds borrowed against the line of credit at December 31, 2015 and 2014. The line of credit requires the Cooperative to pay down the balance to zero annually. Interest rates vary and were 2.90% at December 31, 2015 and 2014. This line of credit expires in March 3, 2017.

At December 31, 2015, KEPCo has a $10 million line of credit available with CoBank, ACB. There were no funds borrowed against the line of credit at December 31, 2015 and 2014. Interest rate options, as selected by the Company, are a weekly quoted variable rate in which CoBank establishes a rate on the first business day of each week or a LIBOR option at a fixed rate equal to LIBOR plus 1.6%. This line of credit expires May 30, 2016.

(7) Short-Term Note Payable

As of December 31, 2014 KEPCo had a short-term note payable in the amount of $1.4 million to the Cooperative Finance Corporation at an interest rate of 2.5%. As of December 31, 2015, this note has been paid off.

(8) Long-Term Debt

Long-term debt consists of mortgage notes payable to the United States of America acting through the Federal Financing Board, the CFC and others. Substantially all of KEPCo's assets are pledged as collateral. The terms of the notes as of December 31 are as follows:

	2015	2014
Mortgage notes payable to the FFB at fixed rates varying from .818% to 9.21%, payable in quarterly installments through 2043	$ 59,050,988	$ 62,732,450
Mortgage notes payable to the Grantor Trust Series 1997 at a rate of 7.522%, payable semi-annually, principal payments commencing in 1999 and continuing annually through 2017	7,240,000	13,140,000
Floating/fixed rate pollution control revenue bonds, City of Burlington, Kansas, Pooled Series 1985C, variable interest rate of .34%, payable annually through 2015	-	1,995,000
Note payable to CoBank at a rate of 3.03%, payable in quarterly installments through 2023	991,073	1,111,684
Mortgage notes payable, equity certificate loans and member capital security notes to the CFC at fixed rates of 2.80% to 7.50%, payable quarterly through 2045	91,391,067	88,831,738
	158,673,128	167,810,872
Less current maturities	(11,456,396)	(15,683,929)
	$ 147,216,732	$ 152,126,943

Notes to Consolidated Financial Statements

Aggregate maturities of long-term debt for the next five years and thereafter are as follows:

2016	$ 11,456,396
2017	10,587,758
2018	7,204,862
2019	7,317,138
2020	7,447,676
Thereafter	114,659,298
	$ 158,673,128

Restrictive covenants related to the CFC debt require KEPCo to design rates that would enable it to maintain a times-interest earned ratio of at least 1.05 and debt-service coverage ratio of at least 1.0, on average, in the two best years out of the three most recent calendar years. The covenants also prohibit distribution of net patronage capital or margins until, after giving effect to any such distribution, total patronage capital equals or exceeds 20% of total assets, unless such distribution is approved by the Rural Utility Service. KEPCo was in compliance with such restrictive covenants as of December 31, 2015 and 2014.

Restriction covenants related to the CoBank debt require KEPCo to design rates that would enable it to maintain a debt-service coverage ratio, as defined by CoBank of at least 1.10. KEPCo was in compliance with the restrictive covenant as of December 31, 2015 and 2014.

In 1997, KEPCo refinanced its mortgage notes payable to the 1988 CFC Grantor Trust through the establishment of a new CFC Grantor Trust Series 1997 (the Series 1997 Trust) by CFC. This refinancing reduced the guaranteed interest rate payable on the mortgage notes to a fixed rate of 7.522%. The mortgage notes payable are pre-payable at any time with no prepayment penalties. The Trust holds certain rights KEPCo assigned to the Trust under an interest rate swap agreement. The swap agreement was put into place in order to mitigate the interest rate risk inherent in the Trust, which holds a fixed rate asset with a variable rate obligation.

The swap agreement terminates in 2017, but is subject to early termination upon the early redemption of the debt. However, any termination costs relating to the termination of the assigned interest rate swaps is KEPCo's responsibility. At December 31, 2015, the termination obligation associated with the assigned swap agreement to early retire the mortgage notes payable is approximately $0.6 million.

This fair value estimate is based on information available at December 31, 2015, and is expected to fluctuate in the future based on changes in interest rates and outstanding principal balance.

KEPCo also is exposed to possible credit loss in the event of noncompliance by the counterparty to the swap agreement. However, KEPCo does not anticipate nonperformance by the counterparty.

Notes to Consolidated Financial Statements

(9) Benefit Plans

National Rural Electric Cooperative Association (NRECA) Retirement and Security Program - KEPCo participates in the NRECA Retirement and Security Program for its employees. The NRECA is a defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the Internal Revenue Code. It is a multiemployer plan under the accounting standards. The plans sponsor's Employer Identification Number is 53-0116145 and the Plan Number is 333.

A unique characteristic of a multiemployer plan compared to a single employer plan is that all plan assets are available to pay benefits of any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

KEPCo's contributions to the Retirement and Security Plan in 2015 and 2014 represented less than 5 percent of the total contributions made to the plan by all participating employers. KEPCo's expense under this program was approximately $0.4 million for each of the years ended December 31, 2015 and 2014, respectively. There have been no significant changes that affect the comparability of 2015 and 2014 contributions.

For the RS Plan, a "zone status" determination is not required, and therefore not determined, under the Pension Protection Act (PPA) of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80 percent funded on January 1, 2015 and over 80 percent funded on January 1, 2014 based on the PPA funding target and PPA actuarial value of assets on those dates.

Because the provisions of the PPA do not apply to the RS Plan, funding improvement plans and surcharges are not applicable. Future contribution requirements are determined each year as part of the actuarial valuation of the plan and may change as a result of plan experience.

NRECA Savings 401(k) Plan - All employees of KEPCo are eligible to participate in the NRECA Savings 401(k) Plan. Under the plan, KEPCo contributes an amount not to exceed 5%, dependent upon each employee's level of participation and completion of one year of service, of the respective employee's base pay to provide additional retirement benefits. KEPCo contributed approximately $100,000 and $90,000 to the plan for the years ended December 31, 2015 and 2014.

WCNOC Pension and Postretirement Plans - KEPCo has an obligation to the WCNOC retirement, supplemental retirement and postretirement medical plans for its 6% ownership interest in Wolf Creek. The plans provide for benefits upon retirement, normally at age 65. In accordance with the Employee Retirement Income Security Act of 1974, KEPCo has satisfied its minimum funding requirements. Benefits under the plans reflect the employee's compensation, years of service and age at retirement.

WCNOC uses a measurement date of December 31 for its retirement plan, supplemental retirement plan and postretirement plan (collectively, the Plans). Information about KEPCo's 6% of the Plans' funded status follows.

Notes to Consolidated Financial Statements

	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
Change in benefit obligation:				
Benefit obligation beginning of year	$ 26,849,361	$ 20,785,543	$ 1,051,925	$ 1,277,753
Service cost	969,547	726,956	17,627	22,122
Interest cost	1,150,940	1,081,152	40,150	59,182
Plan participants' contributions	-	-	119,195	97,847
Benefits paid	(793,702)	(643,257)	(207,086)	(164,795)
Actuarial (gains) losses	(1,824,960)	4,898,967	(26,957)	(240,184)
Benefit obligations, end of year	$ 26,351,186	$ 26,849,361	$ 994,854	$ 1,051,925
Change in plan assets:				
Fair value of plan assets, beginning of year	$ 15,914,004	$ 14,646,824	$ 762	$ 1,990
Actual return on plan assets	(367,512)	973,542	-	-
Employer contributions	741,046	905,022	100,500	65,720
Plan participants' contributions	-	-	119,195	97,847
Benefits paid	(761,388)	(611,384)	(207,087)	(164,795)
Fair value of plan assets, end of year	15,526,150	15,914,004	13,370	762
Funded status, end of year	$ (10,825,036)	$ (10,935,357)	$ (981,484)	$ (1,051,163)

Amounts recognized in the consolidated balance sheets:

	2015	2014
Other long-term liabilities		
Wolf Creek pension and postretirement benefit plans	$ 11,824,521	$ 12,004,519

Amounts recognized in accumulated other comprehensive income (loss) not yet recognized as components of net periodic benefit cost consist of:

	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
Net (loss) gain	$ (7,244,265)	$ (8,304,185)	$ 23,533	$ (3,718)
Prior service cost	(63,998)	(71,323)	-	-
Accumulated other comprehensive (loss) gain	$ (7,308,263)	$ (8,375,508)	$ 23,533	$ (3,718)

Information for the pension plan with an accumulated benefit obligation in excess of plan assets:

	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
Projected benefit obligation	$ 26,351,186	$ 26,849,361	$ (994,854)	$ 1,051,925
Accumulated benefit obligation	23,070,405	22,880,170	-	-
Fair value of plan assets	$ 15,526,150	$ 15,914,004	$ 13,370	$ 762

Weighted average actuarial assumptions used to determine net periodic benefit obligation:

	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
Discount rate	4.61%	4.20%	4.27%	4.70%
Annual salary increase rate	4.00%	4.00%	N/A	N/A

Wolf Creek uses a measurement date of December 31 for its pension and post-retirement benefit plans. The discount rate to determine the current year pension obligation and the following year's pension expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality, non-callable corporate bonds that generate a sufficient cash flow to provide for the projected benefit payments of the plan. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

Notes to Consolidated Financial Statements

	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
Components of net periodic cost (benefit):				
Service cost	$ 969,548	$ 726,956	$ 17,628	$ 22,122
Interest cost	1,150,940	1,081,152	40,150	59,182
Expected return on plan assets	(1,154,587)	(1,031,989)	-	-
Amortization				
Transition obligation, net	-	-	-	-
Prior service cost	7,325	7,436	-	-
Actuarial loss, net	757,059	381,287	294	21,062
Net periodic cost	$ 1,730,285	$ 1,164,842	$ 58,072	$ 102,366
Other changes in plan obligations recognized in other comprehensive income:				
Current year actuarial loss(gain)	$ (302,862)	$ 4,957,414	$ (26,957)	$ (240,184)
Amortization of actuarial loss	(757,059)	(381,287)	(294)	(21,062)
Amortization of prior service cost	(7,325)	(7,436)	-	-
Amortization of transition obligation	-	-	-	-
Total recognized in other comprehensive income	(1,067,246)	4,568,691	(27,251)	(261,246)
Total recognized in net periodic cost and other comprehensive income	$ 663,040	$ 5,733,533	$ 30,821	$ 158,800
Weighted average actuarial assumptions used to determine net periodic cost:				
Discount rate	4.20%	4.20%	3.89%	4.70%
Expected long term return on plan assets	7.50%	7.50%	N/A	N/A
Compensation rate increase	4.00%	4.00%	N/A	N/A

Notes to Consolidated Financial Statements

KEPCo estimates they will amortize the following amounts from regulatory assets into net periodic cost in 2016:

	Pension Benefits	Postretirement Benefits
Actuarial loss	$ 556,200	$ (1,850)
Prior service cost	7,071	-
Total	$ 563,271	$ (1,850)

The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolios. Assumed projected rates of return for each asset class were selected after analyzing long-term historical experience and future expectations of the volatility of the various asset classes. Based on target asset allocations for each asset class, the overall expected rate of return for the portfolios was developed, adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

For measurement purposes, the assumed annual health care cost growth rates were as follows:

	2015	2014
Health care cost trend rate assumed for next year	7.00%	7.00%
Rate to which the cost trend rate is assumed to decline	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2020	2019

The health care cost trend rate affects the projected benefit obligation. A 1% change in assumed health care cost growth rates would have effects shown in the following table:

	One percentage point increase	One percentage point decrease
Effect on total service and interest cost	$ (983)	$ 1,038
Effect on post-retirement benefit obligation	$ (12,178)	$ 12,368

In 2012, Wolf Creek changed its investment advisor resulting in the sale of its then existing levels 1, 2 and 3 investments and the purchase of other level 2 and 3 investments. Its pension and post-retirement plan investment strategy is to manage assets in a prudent manner with regard to preserving principal while providing reasonable returns. It has adopted a long-term investment horizon such that the chances and duration of investment losses are carefully weighed against the long-term potential for appreciation of assets. Part of its strategy includes managing interest rate sensitivity of plan assets relative to the

associated liabilities. The primary objective of the pension plan is to provide a source of retirement income for its participants and beneficiaries, and the primary financial objective of the plan is to improve its funded status. The primary objective of the post-retirement benefit plan is growth in assets and preservation of principal, while minimizing interim volatility, to meet anticipated claims of plan participants. Wolf Creek delegates the management of its pension and post-retirement benefit plan assets to independent investment advisors who hire and dismiss investment managers based upon various factors. The investment advisors strive to diversify investments across asset classes, sectors and manager styles to minimize the risk of large losses, based upon objectives and risk tolerance specified by Wolf Creek, which include allowable and/or prohibited investment types. It measures and monitors investment risk on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

The target allocations for Wolf Creek's pension plan assets are 31% to international equity securities, 25% to domestic equity securities, 25% to debt securities, 10% to real estate securities, 5% to commodity investments and 4% to other investments. The investments in both international and domestic equity include investments in large-, mid- and small-cap companies, private equity funds and investment funds with underlying investments similar to those previously mentioned. The investments in debt include core and high-yield bonds. Core bonds include funds invested in investment grade debt securities of corporate entities, obligations of U.S. and foreign governments and their agencies, and private debt securities. High-yield bonds include a fund with underlying investments in non-investment grade debt securities of corporate entities, private placements and bank debt. Real estate securities include funds invested in commercial and residential real estate properties while commodity investments include funds invested in commodity-related instruments.

All of Wolf Creek's pension plan assets are recorded at fair value using daily net asset values as reported by the trustee. However, level 3 investments in real estate funds and alternative funds are invested in underlying investments that are illiquid and require significant judgment when measuring them at fair value using market and income-based models. Significant unobservable inputs for underlying real estate investments include estimated market discount rates, projected cash flows and estimated value into perpetuity. Alternative funds invest in a wide range of investments typically with low correlations to traditional investments.

Similar to other assets measured at fair value, GAAP establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring pension and post-retirement benefit plan assets at fair value. From time to time, the Wolf Creek pension trust may buy and sell investments resulting in changes within the hierarchy. Where quoted market prices are available in an active market, plan assets are classified within Level 1 of the valuation hierarchy. Level 1 plan assets include cash equivalents, equity and debt investments. If quoted market prices are not available, then fair values are estimated by using pricing models, quoted prices of plan assets with similar characteristics or discounted cash flows. Level 2 investments include cash equivalents, equity, debt and commodity investments. In certain cases where Level 1 or Level 2 inputs are not available, plan assets are classified within Level 3 of the hierarchy and include certain real estate investments. Significant inputs and valuation techniques used in measuring Level 3 fair values include market discount rates, projected cash flows and the estimated value into perpetuity.

Notes to Consolidated Financial Statements

The following table provides the fair value of KEPCo's 6% share of Wolf Creek's pension plan assets and the corresponding level of hierarchy as of December 31, 2015 and 2014:

		Fair Value Measurements Using		
December 31, 2015	Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Cash equivalents	$ 66,902	$ -	$ 66,902	$ -
Equity securities				
U.S.	3,893,997	-	3,893,997	-
International	4,810,439	-	4,810,439	-
Debt securities		-		
Core bonds	3,866,471	-	3,866,471	-
Commodities	741,858	-	741,858	-
Alternative investments	543,482	-	-	543,482
Real estate	1,603,001	-	781,678	821,323
Total	$ 15,526,150	$ -	$ 14,161,345	$ 1,364,805

		Fair Value Measurements Using		
December 31, 2014	Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Cash equivalents	$ 56,659	$ -	$ 56,659	$ -
Equity securities				
U.S. companies	4,031,564	-	4,031,564	-
International companies	4,930,736	-	4,930,736	-
Debt securities				
Core bonds	4,066,416	-	4,066,416	-
Commodities	751,579	-	751,579	-
Alternative investments	550,033	-	-	550,033
Real estate	1,527,017	-	805,883	721,134
Total	$ 15,914,004	$ -	$ 14,642,837	$ 1,271,167

The following tables provides reconciliation of KEPCo's 6% share of Wolf Creek's pension plan assets measured at fair value using significant level 3 inputs for the years ended December 31, 2015 and 2014:

	Real Estate Securities	Alternative Investments
Balance at January 1, 2015	$ 721,134	$ 550,033
Actual return on plan assets		
Relating to assets still held at the reporting date	100,189	(6,551)
Balance at December 31, 2015	$ 821,323	$ 543,482
Balance at January 1, 2014	$ 650,341	$ 529,374
Actual return on plan assets		
Relating to assets still held at the reporting date	70,793	20,659
Balance at December 31, 2014	$ 721,134	$ 550,033

Estimated future benefit payments as of December 31, 2015, for the Plans, which reflect expected future services, are as follows:

	To/from trust	From company assets	To/from trust	From company assets
Expected contributions:				
2016	$ 1,020,000	$ -	$ 77,798	$ -
Expected benefit payments:				
2016	$ 768,995	$ 32,220	$ 227,302	$ -
2017	875,934	32,301	254,605	-
2018	990,346	31,981	291,497	-
2019	1,105,753	32,073	328,966	-
2020	1,222,595	32,001	365,477	-
2021-2024	7,828,560	159,705	2,319,763	-

Notes to Consolidated Financial Statements

(10) Commitments and Contingencies

Current Economic Environment - KEPCo considers the current economic conditions when planning for future power supply and liquidity needs. The current economic climate may also affect KEPCo's ability to obtain financing.

Given the volatility of the current economic conditions, the values of assets and liabilities recorded in the financial statements could change rapidly, resulting in material future adjustments that could negatively impact the Cooperative's ability to meet debt covenants or maintain sufficient liquidity. Currently under state statutes, the Cooperative's rate making is deregulated and, therefore, expects to be able to recover any economic losses through future rates.

Litigation - The Cooperative is subject to claims and lawsuits that arise primarily in the ordinary course of business. It is the opinion of management that the disposition or ultimate resolution of such claims and lawsuits will not have an adverse effect on the consolidated financial position, results of operations and cash flows of the Cooperative.

There is a provision in the Wolf Creek operating agreement whereby the owners treat certain claims and losses arising out of the operations of Wolf Creek as a cost to be borne by the owners separately (but not jointly) in proportion to their ownership shares. Each of the owners has agreed to indemnify the others in such cases.

Letter of Credit - KEPCo has an open letter of credit with the Cooperative Finance Corporation in the amount of $1,500,000 which matures May 23, 2016. This letter of credit renews automatically each year unless notice is given. The letter of credit is intended to provide financial security to Southwest Power Pool pursuant to its credit policy.

Nuclear Liability Insurance - Pursuant to the Price-Anderson Act, which has been reauthorized through December 31, 2025, by the Energy Policy Act of 2005, the Cooperative is required to insure against public liability claims resulting from nuclear incidents to the current limit of public liability, approximately $13.5 billion. This limit of liability consists of the maximum available commercial insurance of $375.0 million and the remaining $13.1 billion is provided through mandatory participation in an industry-wide retrospective assessment program. In addition, Congress could impose additional revenue-raising measures to pay claims. Under this retrospective assessment program, the owners of Wolf Creek are jointly and severally subject to an assessment of up to $127.3 million (KEPCo share is $7.64 million), payable at no more than $19.0 million (KEPCo share is $1.14 million) per incident per year per reactor. Both the total and yearly assessment is subject to an inflationary adjustment every five years with the next adjustment in 2018.

The owners of Wolf Creek carry decontamination liability, premature nuclear decommissioning liability and property damage insurance for Wolf Creek totaling approximately $2.8 billion (KEPCo's share is $168 million). In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the NRC. KEPCo's share of any remaining proceeds can be used to pay for property damage or, if certain requirements are met, including decommissioning the plant, toward a shortfall in the NDT fund.

The owners also carry additional insurance with Nuclear Energy Industry Limited (NEIL) to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, KEPCo may be subject to retrospective assessments under the current policies of approximately $2.52 million.

Although KEPCo maintains various insurance policies to provide coverage for potential losses and liabilities resulting from an accident or an extended outage, KEPCo's insurance coverage may not be adequate to cover the costs that could result from a catastrophic accident or extended outage at Wolf Creek. Any substantial losses not covered by insurance, to the extent not recoverable in rate prices, would have a material effect on KEPCo's consolidated financial results.

Decommissioning Insurances - KEPCo carries premature decommissioning insurance that has several restrictions, one of which can only be used if Wolf Creek incurs an accident exceeding $500 million in expenses to safely stabilize the reactor, to decontaminate the reactor and reactor station site in accordance with a plan approved by the Nuclear Regulatory Commission (NRC) and to pay for on-site property damages.

Once the NRC property rule requiring insurance proceeds to be used first for stabilization and decontamination has been complied with, the premature decommissioning coverage could pay for the decommissioning fund shortfall in the event an accident at Wolf Creek exceeds $500 million in covered damages and causes Wolf Creek to be prematurely decommissioned.

Nuclear Fuel Commitments - At December 31, 2015, KEPCo's share of WCNOC's nuclear fuel commitments was approximately $2.1 million for uranium concentrates expiring in 2017, $0.3 million for conversion expiring in 2017, $12.0 million for enrichment expiring at various times through 2045 and $4.2 million for fabrication through 2045.

Purchase Power Commitments - KEPCo has supply contracts with various utility companies to purchase power to supplement generation in the given service areas. KEPCo has provided the Southwest Power Pool a letter of credit to help insure power is available if needed.

(11) Fair Value of Assets and Liabilities

ASC Topic 820, *Fair Value Measurements,* defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

ASC Topic 820 also establishes a fair value hierarchy which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value:

Level 1 Quoted prices in active markets for identical assets or liabilities

Level 2 Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities

Level 3 Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities

Following is a description of the valuation methodologies used for assets and liabilities measured at fair value on a recurring basis and recognized in the accompanying consolidated balance sheets, as well as the general classification of such assets and liabilities pursuant to the valuation hierarchy.

Decommissioning Fund - The decommissioning fund consists of various mutual funds where fair value is determined by quoted market prices in an active market and, as such, are classified within Level 1 of the valuation hierarchy.

The following table presents the fair value measurements of assets and liabilities recognized in the accompanying consolidated balance sheets measured at fair value on a recurring basis and the level within the ASC 820 fair value hierarchy in which the fair value measurements fall at December 31, 2015:

		Fair Value Measurements Using		
	Fair Value	Quoted price in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Decommissioning fund				
Domestic fund	$ 10,865,536	$ 10,865,536	$ -	$ -
International fund	1,440,767	1,440,767	-	-
Domestic bond fund	7,189,822	7,189,822	-	-
Money market	500,071	500,071	-	-
Total	$ 19,996,196	$ 19,996,196	$ -	$ -

Notes to Consolidated Financial Statements

The following methods were used to estimate the fair value of all other financial instruments recognized in the accompanying consolidated balance sheets at amounts other than fair value.

Cash and Cash Equivalents - Due to the short term maturity of cash and cash equivalents, the carrying amount approximates fair value.

Investments in CFC and Other Associated Organizations - KEPCo considers CFC and other associated organizations certificates to be a condition of borrowing and patronage capital certificates to be directly related to borrowing. As such, KEPCo management believes the fair value of these assets is not determinable and they are reflected at their carrying amount.

Bond Fund Reserve - The bond fund reserve consists of various held-to-maturity securities where the fair value is primarily based on quoted market prices.

Line of Credit and Long-Term Debt

Variable-Rate Debt - The carrying amount approximates fair value because of the short-term variable rates of those debt instruments.

Fixed-Rate Debt - The fair value of all fixed-rate debt is based on the sum of the estimated value of each issue, taking into consideration the current rate offered to KEPCo for debt of similar remaining maturities.

The following table presents estimated fair values of KEPCo's financial instruments at December 31, 2015 and 2014:

	December 31, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Cash and cash equivalents	$ 6,307,421	$ 6,307,421	$ 1,202,643	$ 1,202,643
Bond fund reserve	-	-	4,490,786	4,531,117
Financial liabilities:				
Long-term debt	$ 158,673,128	$ 171,937,869	$ 167,810,872	$ 187,686,399

(12) Patronage Capital

In accordance with KEPCo's bylaws, KEPCo's current margins are to be allocated to members. KEPCo's current policy is to allocate to the members based on revenues collected from the members as a percentage of total revenues. As disclosed in note 3, if KEPCo's consolidated financial statements were adjusted to reflect accounting principles generally accepted in the United Stated of America, total patronage capital would be substantially less. As noted in the consolidated statements of changes in patronage capital, no patronage capital distributions were made to members in 2015 and 2014.

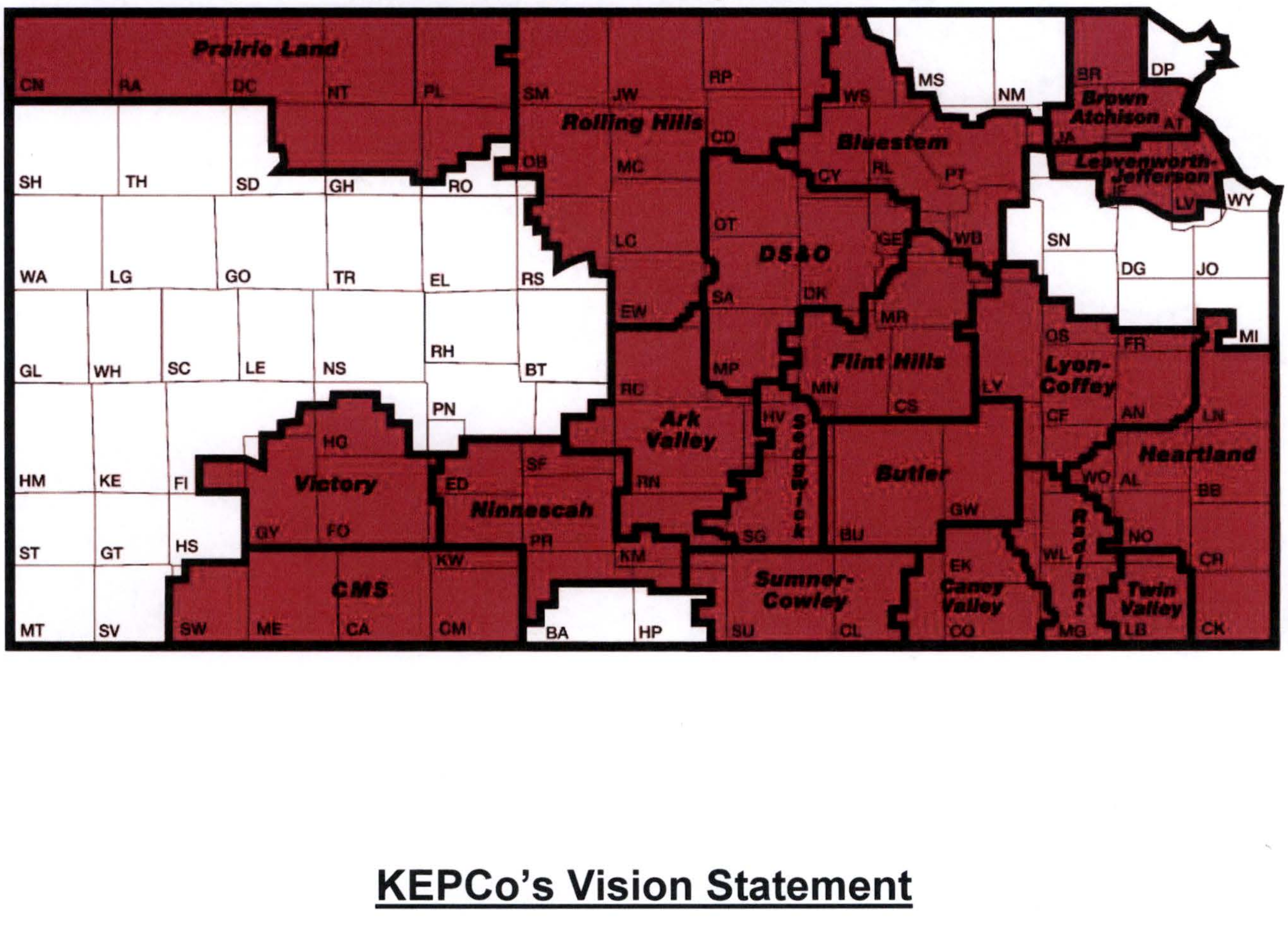
(13) Subsequent Events

The Company has evaluated subsequent events through April 6, 2016, which is the date the financial statements were available to be issued. No events were significant enough to warrant disclosures in the accompanying financial statements or notes.

KEPCo's Mission Statement

KEPCo exists on behalf of its Members to produce, procure, transmit, deliver and maintain a reliable supply of wholesale electricity within financial guidelines and risk tolerances established by the Board.

KEPCo Member System Map



KEPCo's Vision Statement

KEPCo will work to provide Consumer-Members the best possible value in reliable electricity and to play an active role in helping improve the economy and quality of life.

Kansas Electric
Power Cooperative, Inc.

A Touchstone Energy® Cooperative

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2015

Annual Report

KANSAS ELECTRIC POWER
COOPERATIVE, INC.