WOLF CREEK
NUCLEAR OPERATING CORPORATION

Michael J. Westman
Manager Regulatory Affairs

May 6, 2014

RA 14-0035

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

Subject: Docket No. 50-482: Transmittal of 2013 Annual Financial Reports

Gentlemen:

Wolf Creek Nuclear Operating Corporation (WCNOC) is transmitting one copy each of the enclosed 2013 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) 364-4009 or Mr. Bill Muilenburg at (620) 364-4186.

Sincerely,

Michael J. Westman

MJW/rlt

Enclosures: I Westar Energy 2013 Annual Report
II Great Plains Energy 2013 Annual Report
III Kansas Electric Power Cooperative, Inc. 2013 Annual Report

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

M004
NRR

2013 ANNUAL REPORT

Westar Energy®

Taking energy to heart.

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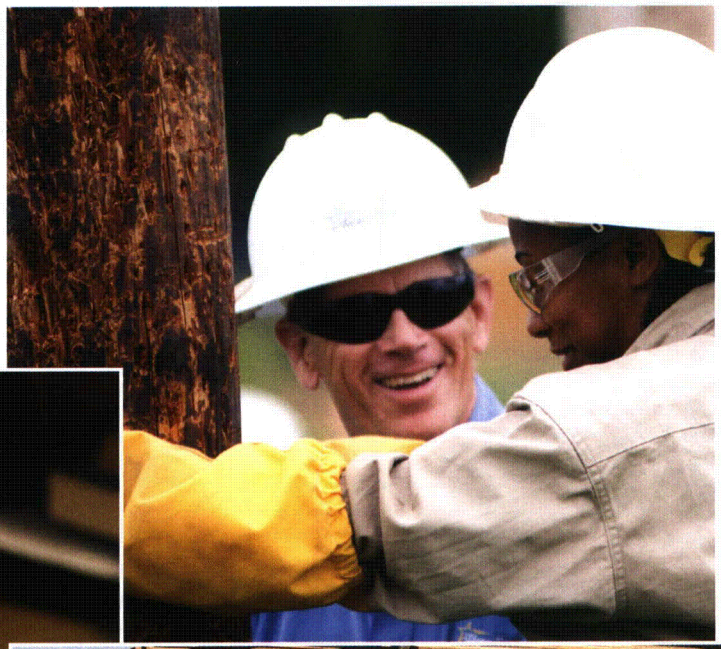
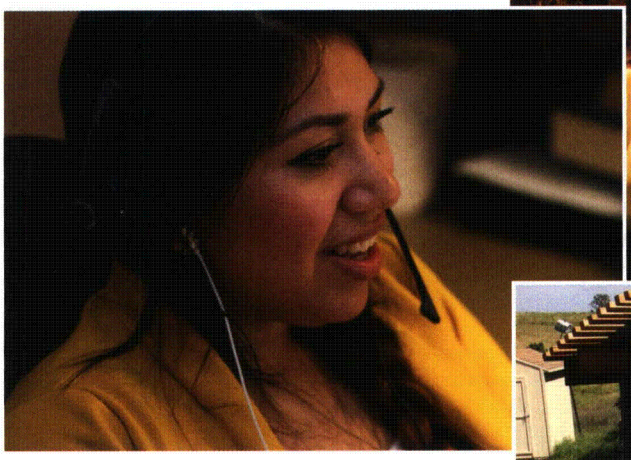


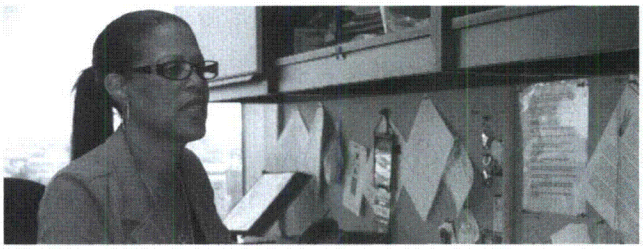


On the cover: ***Luke Justice, agent (left), and Clint Tankersley, line foreman (right) prepare for the 30th Annual International Lineman's Rodeo in Overland Park, Kan.***

Justice and Tankersley teamed up to prepare for a series of events in a competition that reminds workers to maintain focus on safe work practices, and provides a forum for the public to better understand and recognize the technical craft skills of linemen.

At Westar Energy, we take our community and its safety to heart. We are committed to helping you and your loved ones stay safe around electricity, while enhancing your way of life. We strive to be an outstanding model of civic leadership and environmental stewardship. Our workforce is committed to operating a safe, reliable and innovative electric utility with uncompromising integrity.

Dear Shareholders,



The typical U.S. corporation lasts maybe a couple of decades. Your company, Westar Energy, is well over a century old.

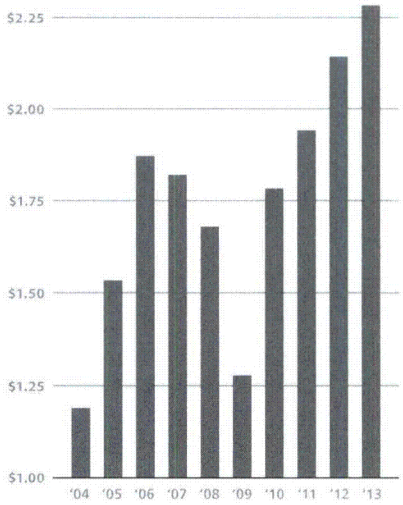
As your management, we always remember that we're stewards of something larger than ourselves. Our job is to perpetuate strong growth, profitability and excellent customer service for a company that should outlast us all if we do well.

Fanfare and publicity are overrated. Companies that find themselves in the headlines for bold action often quickly find themselves in the headlines for missteps. Our approach is a little different. We still believe that steady progress wins the race, something evident in the tables below.

Thoughtful moves, however, still require deliberate action. We live in a highly dynamic environment filled with risk and uncertainty, technological advances, shifting government policies, and changing customer needs and preferences. Perpetuating and growing your investment in Westar Energy requires navigating change and risk in a way that positions the company for the future without sacrificing the firm foundation on which it rests today.

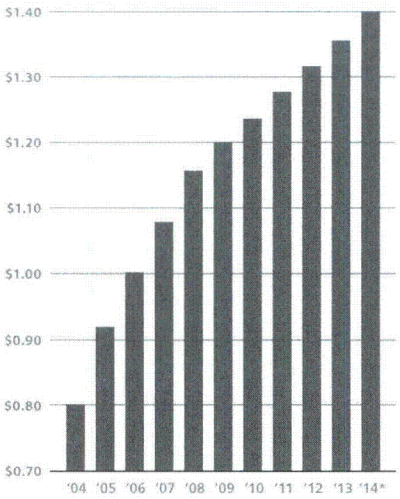
I'd like to share a few thoughts about how your management team is doing that. We believe there is a "no regrets" approach to the future — one that preserves the strength of Westar today and positions it for future success.

COMPOUND EARNINGS PER SHARE GROWTH OF 7.5%



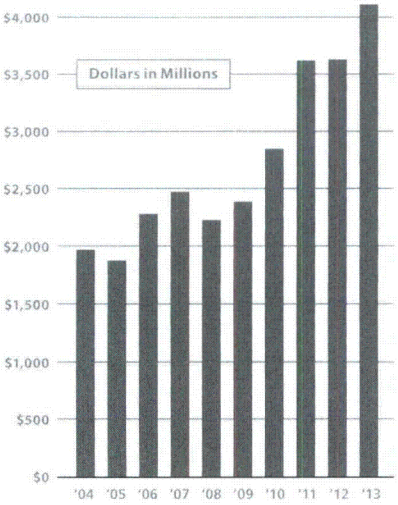
EPS from continuing operations

COMPOUND DIVIDEND GROWTH OF 5.8%



**Indicated annual rate*

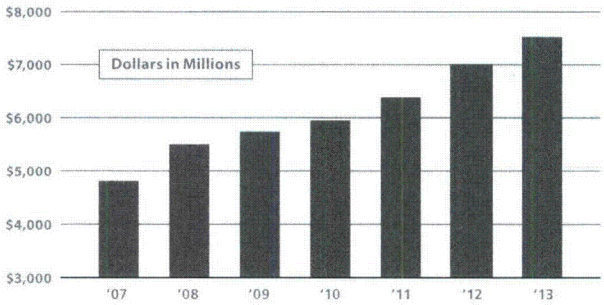
DOUBLING WESTAR'S MARKET CAPITALIZATION



WE'RE INVESTING IN A STRONG FUTURE.

In the past seven years, we have invested more than $5 billion to meet our customers' needs for efficient, secure, reliable and cleaner energy.

NET PROPERTY, PLANT AND EQUIPMENT



We have done this by honoring the time-tested principle of diversification. No single investment in property, plant and equipment represents more than 8 percent of the total, and no single category represents more than 30 percent.

Demand for how we produce and deliver electricity — with efficiency, reliability, security and care for our environment — drives our investment as much as the increase in demand for electricity itself.

WE'RE IMPROVING GRID RELIABILITY AND EFFICIENCY.

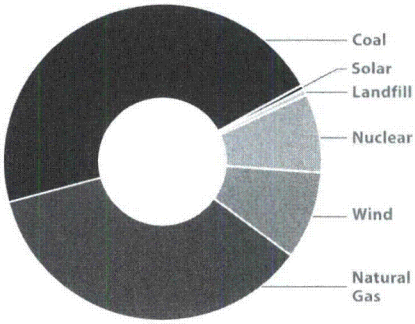
Electricity is a mature business and components of the transmission grid are aging. To meet our customers' future energy needs, we are rebuilding and investing in new transmission lines to maximize the efficiency of our power plants; obtain the lowest cost power for our customers; gain access to more renewable energy; and improve the safety, reliability and security of the power grid, on which so many depend.

What was once a relatively small part of our investment base will soon represent nearly a quarter of our plant investment.

DIVERSE ENERGY RESOURCES

Electricity can be produced through many methods, each with its own advantages and disadvantages. True to the adage, "There is no free lunch," Westar Energy believes the best approach to balance the needs of our customers, Kansas and our environment is to diversify by using some of each method.

Generating Capacity Based on Fuel Type (MWs)[1]



[1] *Includes wind generation and landfill gas facilities in which we purchase energy pursuant to purchase power agreements*

RENEWABLE ENERGY

WIND ENERGY

Advantages: Produces no emissions; wind is abundant in Kansas.

Disadvantages: *Wind turbines produce electricity only when the wind is blowing; they affect the landscape because of their size; wind energy is not cost competitive without significant government subsidies.*

SOLAR ENERGY

Advantages: No emissions; typically produces "peak" energy on hot summer days when energy is in greatest demand; solar panels can be integrated into existing buildings by placing them on rooftops.

Disadvantages: *Solar panels produce electricity only in the sunshine; without sunshine, they require expensive backup batteries or they must be "plugged in" to the grid to maintain reliable service.*

LANDFILL GAS

Advantages: Captures and puts to use unwanted release of methane gas, which results in less greenhouse gas emissions; can produce power around the clock; cost competitive.

Disadvantages: *Small scale and limited availability.*

ADVANTAGES OF A DIVERSIFIED PLANT PORTFOLIO.

More than a century of operating reminds us that each method of generating electricity has both advantages and disadvantages, with the disadvantages often catching the world by surprise.

Wind turbines and solar panels produce the cleanest energy, but are dependent on weather conditions that are not always present when our customers need electricity. Natural gas power plants depend on a "just-in-time" fuel supply, which in times of extremely cold weather can suffer interruption. Baseload nuclear and coal plants, however, have the capability of storing large quantities of fuel inventory at the plant site. Storing these fuels helps minimize interruptions in the supply of electricity, but of course, they have their oft-cited disadvantages, too.

Although it may be tempting to go "all in" with a particular method of producing electricity, we believe having a variety of generating resources is important. Diversification contributes to increased reliability and more stable power prices for our customers.

It has been decades since we built any new baseload power plants. In recent years, we have vastly expanded our commitment to renewable energy and cleaner-burning natural gas. Our older baseload plants are still valuable and must remain safe and reliable for decades to come. We continue to make investments to ensure that our coal plants get increasingly cleaner.

The equipment we've installed to reduce power plant emissions represents more than $1.5 billion of investment in clean air and our future.

In recent years, the magnitude of our capital commitments have made ours one of the largest construction programs in our industry — relative to our size. I'm pleased to share that while this investment

FOSSIL FUELS

NATURAL GAS TURBINES

Advantages: **Reliable, flexible and can produce power around-the-clock; produces less emissions than coal.**

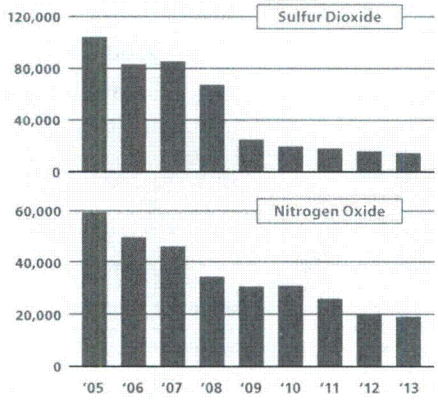
Disadvantages: *Natural gas is more expensive than coal and has a very volatile price history; occasional disruptions in just-in-time fuel delivery through pipelines can disrupt electricity production.*

COAL POWER PLANTS

Advantages: **Very reliable; lowest cost method of producing electricity from fossil fuel; coal has a stable price history with little volatility.**

Disadvantages: *Higher carbon emissions than natural gas. While Westar has invested to make its coal plants increasingly cleaner by reducing emissions, a method of eliminating carbon emissions does not exist today.*

Emission Levels *(tons)*



NUCLEAR POWER

Advantages:

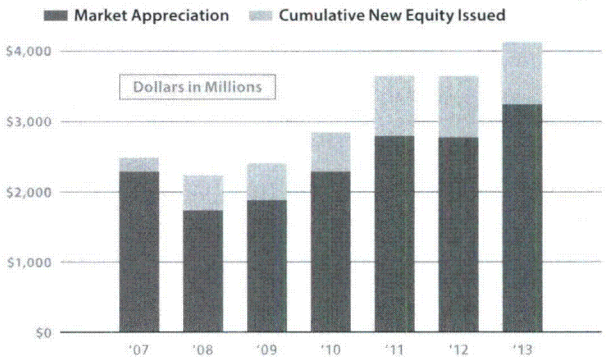
No emissions; very reliable; produces around-the-clock power with the lowest cost of fuel of any thermal power generation.

Disadvantages:

Plants are very expensive to build and operate; requires specialized and expensive skills to assure safety; "spent fuel" waste product must be carefully controlled long after the plant is no longer being used.

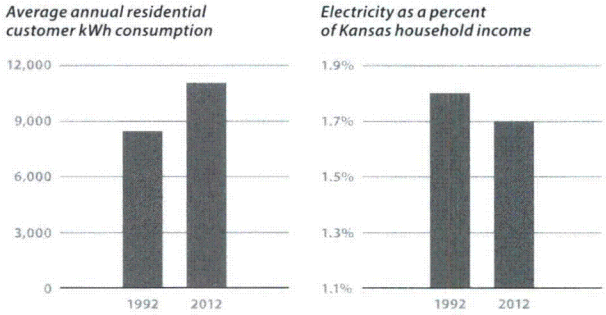
meant selling more shares, the value that Westar shareholders earned from these investments far exceeds the "cost" of issuing the additional shares. Westar Energy stock outstanding is now worth in excess of $4 billion, double what it was just a few years ago.

MARKET CAPITALIZATION



Investments to keep our electric service safe, reliable and in compliance with increasingly stringent regulations come with another cost — higher prices. After decades of flat and even falling rates, we have had to raise our prices in the last few years. Fortunately, we've been able to navigate higher costs in a way that still has our customers paying less for their Westar electricity than is typical across the country. Even though our customers are using more electricity today, the cost of it amounts to a smaller portion of their incomes than it did two decades ago.

RESIDENTIAL ELECTRICITY



Source: WR and KGE FERC Form 1, US Census Bureau, and acf.hhs.gov

With the largest portion of this capital investment program behind us, we can see forward to a period where we can continue to grow your company without issuing additional shares and with more modest price increases for our customers.

As a management team, we're proud of Westar Energy's accomplishments over the past few years: doubling our investment base; completing massive capital projects safely, favorable to budget and on schedule; improving the reliability, security and efficiency of our service; and dramatically improving the air quality in our environment. However, there is no time for reflection or looking back.

THE UTILITY INDUSTRY IS UNDERGOING TRANSFORMATIVE CHANGE DRIVEN BY TECHNOLOGY AND PUBLIC POLICY.

Westar's next big challenge likely will not require the capital investment of the past few years. It will require something even harder to muster — the need to adapt our service to our customers' changing preferences.

Although we've successfully adapted to *evolutionary* technological changes, the electric utility industry has, until now, largely avoided the *revolutionary* changes of the digital world. That seems to be changing.

No longer is it adequate for us to compare our performance only to other utilities. Our customers increasingly compare Westar's electric service and their interactions with us to other products and services they purchase: their mobile telephone, Internet and entertainment services, for example. They expect more choice, control, interaction and mobility. They want more payment options and plans to suit their lifestyle — the way they choose cell phone plans that meet their families' needs and don't leave them surprised when they receive their bill. Neither is it always about the lowest price. Even though today it may be more costly, some of our customers want to explore the option of generating some of their own power alongside of and in partnership with us.

Why will making such changes pose challenges for us and our regulators? Our systems, pricing structure and, the rules and regulations around utility service were developed and perfected at a time when customer demands were more uniform. One-size-fits-all programs no longer satisfy their diverse expectations.

An example: our collection process. We are working with regulators to modernize it. As with any product or service, occasionally, some customers have difficulty paying their electric bill. Our procedure today consists of contacting them by phone, mail and sending collection agents in a final attempt to avoid interrupting their electric service. The vast majority of our customers prefer to be contacted using more modern and less intrusive methods, such as text messages and emails. We believe that listening to our customers and following up with top-notch service is the key to maximizing long-term value for them and delivering shareholder value to you.

OUR CUSTOMERS, SHAREHOLDERS, COMMUNITIES AND EMPLOYEES ARE OUR FUNDAMENTAL PRIORITIES.

While we will have plenty to do to keep up with technological advances and our customers' changing preferences, I'm pleased to share that we start from a good place and a strong foundation. Customers are pleased with our service, as they demonstrate with their opinions about our interaction with them. For each of the past four years, they have given us increasingly better ratings for our service.

Safety is one of our core values. It is vital for Westar professionals to identify and avoid associated hazards and protect our customers and communities from harm and inconvenience. I'm pleased to share that our employees achieved record safety again — among the very best in the entire industry.

The nature of our business — one that requires long-lived, fixed investments in infrastructure — means that our company can only be as strong as the communities we have the privilege of serving. Your investment and the lives of the people who work at Westar are tied to our communities' strength and well being. I'm proud of our employees' consistent commitment to the communities in which they live and work. Last year, Westar employees gave record amounts of their dollars, time and leadership expertise to local charities. One hundred-twenty charitable and community organizations benefit from having a Westar Energy leader serving on their board. Our Green Team, a group of employee and retiree volunteers, completed 60 environmental projects across Kansas.

INVESTING IN PEOPLE IS VITAL IN PREPARING WESTAR ENERGY TO MEET THE TRANSFORMATIVE CHANGES AHEAD.

Westar Energy has partnered with our public schools to stimulate young minds toward studies in math, science and engineering. We're working collaboratively with the Topeka Public Schools to provide a venue for young people to learn about science and electricity.

These partnerships not only keep our communities and local economies strong, they give us a head start in finding and developing future professionals who have the desire, competence and vision to pave the way for the next 100 years.

I hope you are pleased with the financial and overall performance of your company in 2013. Consecutively higher earnings have given the board of directors confidence in continuing to raise your dividend. Last year, Standard and Poor's recognized our strong financial foundation by raising our credit rating. Westar now receives an "A" rating on its senior secured debt from all three major credit rating agencies.

Our operating principles of safety, reliability, innovation and having financial discipline are as relevant today as they were over 100 years ago. I am grateful for the support of our board of directors and shareholders as we continue to position the company for success. We can accomplish nothing without your continued trust and confidence in us as stewards of your investment. Thank you.

Sincerely,

Mark A. Ruelle
President and Chief Executive Officer

2013 Financial Measures.

	2013	2012
FINANCIAL DATA *(Dollars in Millions)*		
INCOME HIGHLIGHTS		
Revenues	**$2,371**	$2,261
Net income	**301**	282
Net income attributable to common stock	**293**	274
BALANCE SHEET HIGHLIGHTS		
Total assets	**$9,597**	$9,265
Common stock equity	**3,063**	2,896
Capital structure:		
Common equity	**47%**	49%
Noncontrolling interests	**<1%**	<1%
Long-term debt, including VIEs	**53%**	51%
OPERATING DATA		
Sales (Thousands of MWh)		
Retail	**19,496**	19,938
Wholesale	**8,593**	7,719
Customers	**693,000**	690,000
COMMON STOCK DATA		
PER SHARE HIGHLIGHTS		
Basic earnings per common share	**$2.29**	$2.15
Dividends declared per common share	**$1.36**	$1.32
Book value per share	**$23.88**	$22.89
STOCK PRICE PERFORMANCE		
Common stock price range:		
High	**$34.96**	$33.04
Low	**$28.59**	$26.80
Stock price at year end	**$32.17**	$28.62
Average equivalent common shares outstanding (in thousands)	**127,463**	126,712
Dividend yield (based on year end annualized dividend)	**4.2%**	4.6%

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, 2013

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 $4,056,844,230 at June 30, 2013.

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	128,791,042 shares
(Class)	(Outstanding at February 18, 2014)

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 2014 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
BACT	Best Available Control Technology
BNSF	BNSF Railway Company
Btu	British thermal units
CAMR	Clean Air Mercury Rule
CCB	Coal combustion byproduct
CO	Carbon monoxide
CO_2	Carbon dioxide
COLI	Corporate-owned life insurance
CSAPR	Cross-State Air Pollution Rule
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	Department of Energy
DSPP	Direct Stock Purchase Plan
ECRR	Environmental Cost Recovery Rider
EPA	Environmental Protection Agency
EPS	Earnings per share
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gas
IM	Integrated Marketplace
IRS	Internal Revenue Service
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
La Cygne	La Cygne Generating Station
LTISA Plan	Long-Term Incentive and Share Award Plan
MATS	Mercury and Air Toxics Standards
MMBtu	Millions of Btu
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
NSPS	New Source Performance Standard
PCB	Polychlorinated biphenyl
PM	Particulate matter
PRB	Powder River Basin
RECA	Retail energy cost adjustment
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
SCR	Selective catalytic reduction
SEC	Securities and Exchange Commission
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
SSCGP	Southern Star Central Gas Pipeline
Staff	Staff of the Securities Exchange Commission
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:

- the risk of operating in a heavily regulated industry subject to frequent and uncertain political, legislative, judicial and regulatory developments at any level of government that can affect our revenues and costs,
- the difficulty of predicting the amount and timing of changes in demand for electricity, including with respect to emerging competing services and technologies,
- weather conditions and their effect on sales of electricity as well as on 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, 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 frequently changing laws and regulations relating to air and greenhouse gas 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,
- current and future litigation, regulatory investigations, proceedings or inquiries,
- other circumstances affecting anticipated operations, electricity sales and costs, 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 693,000 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 and diverse energy supply portfolio. In doing so, we continue to make environmental upgrades to our coal-fired power plants, develop renewable generation, build and upgrade our electrical infrastructure, and develop systems and programs with regard to how our customers use energy.

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,	2013	2012	2011
Residential	31%	32%	32%
Commercial	28%	28%	28%
Industrial	16%	16%	16%
Wholesale	15%	14%	16%
Transmission	9%	9%	7%
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,	2013	2012	2011
Residential	34%	34%	35%
Commercial	38%	38%	37%
Industrial	28%	28%	28%
Total	100%	100%	100%

Generation and Firm Capacity Purchases

We have 6,571 megawatts (MW) of accredited generating capacity in service. See "Item 2. Properties" for additional information about our generating units. We own electricity generating facilities or purchase electricity pursuant to long-term contracts from renewable generation facilities with an installed design capacity of 664 MW. Because of the intermittent nature of wind generation, only 14 MW of accredited generating capacity is associated with wind generation facilities. Our capacity and net generation by fuel type are summarized below.

Fuel Type	Capacity (MW)	Percent of Total Capacity	Net Generation (MWh)	Percent of Total Net Generation
Coal	3,424	52%	20,677,415	73%
Nuclear	547	8%	3,369,101	12%
Natural gas/diesel	2,599	39%	1,785,382	6%
Renewable	1	<1%	426,919	2%
Renewable purchase contracts	13	<1%	1,894,308	7%
Total	6,584	100%	28,153,125	100%

In November, 2013 we entered into a renewable energy purchase agreement. Under the agreement, we plan to purchase an additional 200 MW of installed designed capacity to be delivered by the end of 2016.

Our aggregate 2013 peak system net load of 5,186 MW occurred in July 2013. Our net generating capacity, combined with firm capacity purchases and sales and potentially interruptible load, provided a capacity margin of 19% above system peak responsibility at the time of our 2013 peak system net load, which satisfied Southwest Power Pool (SPP) planning requirements.

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

Utility[a]	Capacity (MW)	Expiration
Oklahoma Municipal Power Authority	61	December 2013
Midwest Energy, Inc.	75	December 2015
Midwest Energy, Inc.	120	May 2017
Midwest Energy, Inc.	35	May 2017
Mid-Kansas Electric Company, LLC	174	January 2019
Kansas Power Pool	59	March 2020
Midwest Energy, Inc.	150	May 2025
Other	13	December 2013 – May 2015
Total	687	

[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 2013, 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 volume of fuel required to produce a given amount of electricity. We measure the quantity of heat consumed during the generation of electricity in millions of Btu (MMBtu).

Coal

Jeffrey Energy Center (JEC): The three coal-fired units at JEC have an aggregate capacity of 2,155 MW, of which we own or consolidate through a variable interest entity (VIE) a combined 92% share, or 1,983 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 2013 was approximately $1.77 per MMBtu, or $29.22 per ton.

La Cygne Generating Station (La Cygne): The two coal-fired units at La Cygne have an aggregate generating capacity of 1,418 MW, of which we own or consolidate, through a VIE a 50% share, or 709 MW. 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 70%, 40% and 20% of La Cygne's PRB coal requirements are under contract for 2014, 2015 and 2016, respectively. About 80% of those commitments under contract for 2014 are fixed price and all of those commitments under contract are fixed price for 2015 and 2016. 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 2013, our share of average delivered cost of coal consumed at La Cygne was approximately $2.06 per MMBtu, or $35.81 per ton.

Lawrence and Tecumseh Energy Centers: Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 732 MW. We purchase PRB coal for these energy centers under a contract with Arch Coal, Inc., which we expect to provide 100% of the coal requirements through 2014. BNSF transports coal for these energy centers under a contract that expires in December 2020, at which time we plan to enter into a new contract.

During 2013, the average delivered cost of coal consumed in the Lawrence units was approximately $1.78 per MMBtu, or $31.43 per ton. The average delivered cost of coal consumed in the Tecumseh units was approximately $1.74 per MMBtu, or $30.96 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, at the State Line facility and in the gas turbine units at Tecumseh Energy Center. We can also use natural gas as a supplemental fuel in the coal-fired units at Lawrence and Tecumseh Energy Centers. During 2013, we consumed 19.0 million MMBtu of natural gas for a total cost of $83.8 million, or approximately $4.41 per MMBtu. Natural gas accounted for approximately 7% of the total MMBtu of fuel we consumed and approximately 16% of our total fuel expense in 2013. 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 extends through April 1, 2020, and the agreement for Lawrence and Tecumseh Energy Centers expires April 1, 2030. The agreement for the State Line facility extends through July 30, 2017, while the agreement for Emporia Energy Center is in place until December 1, 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 1,164 MW nuclear power plant located near Burlington, Kansas. KGE owns a 47% interest in Wolf Creek, or 547 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 September 2016 and approximately 70% of the uranium and conversion services needed after that date through March 2021. 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. In early 2014, Wolf Creek will undergo a planned maintenance outage. Because the outage is not part of a refueling outage, the related costs will be expensed as incurred. We expect our share of the outage to be approximately $9.0 million.

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 outages. During outages at the plant, we meet our electric demand primarily with our other generating units and by purchasing power.

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

As discussed under "Environmental Matters — Renewable Energy Standard" below, Kansas law requires that our energy supply resources consist of a certain amount of renewable sources. For us, wind has been the primary source of renewable energy. As of December 31, 2013, we owned approximately 149 MW of designed installed wind capacity and had under contract the purchase of wind energy produced from approximately 715 MW of designed installed wind capability. Of the 715 MW under contract, 200 MW are associated with an agreement pursuant to which a generation provider is scheduled to deliver power beginning in 2016.

Other Fuel Matters

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

	2013	2012	2011
Per MMBtu:			
Nuclear	$ 0.75	$ 0.70	$ 0.68
Coal	1.82	1.86	1.74
Natural gas	4.41	3.20	4.81
Diesel	22.89	23.12	19.33
All generating stations	1.91	1.84	1.92
Per MWh Generation:			
Nuclear	$ 7.86	$ 7.28	$ 7.15
Coal	20.26	20.59	19.30
Natural gas/diesel	46.38	33.29	52.65
All generating stations	20.45	19.65	20.60

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. Transmission constraints may limit our ability to bring purchased electricity into our control area, potentially requiring us to curtail or interrupt our customers as permitted by our tariffs. In 2013, purchased power comprised approximately 18% of our total fuel and purchased power expense. Our weighted average cost of purchased power per Megawatt hour (MWh) was $33.63 in 2013, $26.41 in 2012 and $34.27 in 2011.

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 nine 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.

Developing Forward Market in SPP

The SPP is scheduled to launch an Integrated Marketplace (IM) in March 2014. The SPP IM will be similar to other organized power markets currently operating in other RTOs. The SPP IM will change how we currently sell the output from our generation facilities and buy power to meet the needs of our customers. The SPP will have the authority to start and stop generating units participating in the market and will select the lowest cost resource mix to meet the needs of the various SPP customers while ensuring reliable operations of the transmission system. As with other organized markets, there will be additional market related products, revenues, and charges. Westar recently submitted the necessary regulatory filings seeking to recognize the associated revenues and charges in the prices we charge our customers, similar to our current retail energy cost adjustment tariff.

Regulation and Our Prices

Kansas law gives the Kansas Corporation Commission (KCC) general regulatory authority over our 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 formulae that track changes in our costs, which reduce 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

General

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. These laws and regulations 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. We are currently permitted to recover certain of these costs through the environmental cost recovery rider (ECRR), which, in comparison to a general rate review, reduces the amount of time it takes to begin collecting in retail prices the costs associated with capital expenditures for qualifying environmental improvements. However, there can be no assurance that the costs to comply with existing or future environmental laws and regulations will not have a material effect on our operations or consolidated financial results. Certain key environmental issues, laws and regulations facing us are described further below.

Air Emissions

We must comply with the federal Clean Air Act, 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. In addition, our power plants that burn fossil fuels emit carbon dioxide, which is also regulated under the Clean Air Act and for which the EPA is presently developing regulations.

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 some of our 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 2013, we had adequate SO_2 allowances to meet planned generation and we expect to have enough to cover emissions under this program in 2014.

Cross-State Air Pollution Rule

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) requiring 28 states, including Kansas, Missouri and Oklahoma, to further reduce power plant emissions of SO_2 and NOx beginning January 2012, with further reductions required beginning January 2014. In August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR and remanded the rule to the EPA to promulgate a replacement. This decision is now under review by the U.S. Supreme Court. We cannot at this time predict the outcome of the U.S. Supreme Court's review; however, based on our current and planned environmental controls, if the regulations were to be reinstated or replaced, either in part or in whole, we do not believe the impact on our operations and consolidated financial results would be material.

National Ambient Air Quality Standards

Under the federal Clean Air Act, the EPA sets National Ambient Air Quality Standards (NAAQS) for certain emissions considered harmful to public health and the environment, including two classes of PM, 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. KDHE, our state environmental regulatory agency, proposed to designate portions of the Kansas City area nonattainment for the eight-hour ozone standard. The EPA has not acted on KDHE's proposed designation of the Kansas City area and it is uncertain when, or if, such a designation might occur. The Wichita area also exceeded the eight-hour ozone standard and could be designated nonattainment in the future potentially impacting our operations.

In September 2011, the President instructed the EPA not to implement its more stringent 2008 Ozone Standard since a new NAAQS for ozone was due to be proposed in 2013 and finalized in 2014. We are waiting on this new standard and cannot at this time predict the impact it may have on our operations, but it could be material.

In December 2012, the EPA strengthened an existing NAAQS for one class of PM. By the end of 2014, the EPA anticipates making final attainment/nonattainment designations under this rule and expects to issue a final implementation rule. We are currently evaluating the rule, however, we cannot at this time predict the impact it may have on our operations or consolidated financial results, but it could be material.

In 2010 the EPA strengthened the NAAQS for both NOx and SO_2. We continue to communicate with our regulators regarding these standards and are currently evaluating what impact this could have on our operations and consolidated financial results. If we are required to install additional equipment to control emissions at our facilities, the revised NAAQS could have a material impact on our operations and consolidated financial results.

Mercury and Other Air Emissions

The operation of power plants results in emissions of mercury, acid gases and other air toxics. In 2012, the EPA's Mercury and Air Toxics Standards (MATS) for power plants became effective, replacing the prior federal Clean Air Mercury Rule (CAMR) and requiring significant reductions in mercury, acid gases and other emissions. We expect to be compliant with the new standards by April 2016 as approved by KDHE. We continue to evaluate the new standards and believe that our related investment will be approximately $17.0 million.

Greenhouse Gases

Byproducts of burning coal and other fossil fuels include carbon dioxide (CO_2) and other gases referred to as greenhouse gases (GHGs), which are believed by many to contribute to climate change. The EPA has proposed using the federal Clean Air Act to 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 January 2014, the EPA re-proposed a New Source Performance Standard (NSPS) that would limit CO_2 emissions for new coal and natural gas fueled generating units. The re-proposal would limit CO_2 emissions to 1,000 lbs per MWh generated for larger natural gas units and 1,100 lbs per MWh generated for smaller natural gas units and coal units. Final regulations are expected later in 2014. The EPA was also directed to issue proposed standards addressing CO_2 emissions for modified, reconstructed and existing power plants by June 2014, issue final rules by June 2015, and require that states submit their implementation plans to the EPA no later than June 2016. We cannot at this time determine the impact of such proposals on our operations and consolidated financial results, but we believe the costs to comply could be material.

Under regulations known as the Tailoring Rule, the EPA regulates GHG emissions from certain stationary sources. The regulations are being implemented pursuant to two federal Clean Air Act programs which impose recordkeeping and monitoring requirements and also mandate the implementation of best available control technology (BACT) for projects that cause a significant increase in GHG emissions (defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors). The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. We cannot at this time determine the impact of these regulations on our future operations and consolidated financial results, but we believe the cost of compliance with the regulations could be material.

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 are expected to be issued by the EPA in 2014. Although we cannot at this time determine the timing or impact of compliance with any new regulations, more stringent regulations could have a material impact on our operations and consolidated financial results.

In 2011, the EPA issued a proposed rule that would increase the requirements for cooling intake structures at power plants over concerns about impacts to aquatic life. We are currently evaluating the proposed rule as well as recent nationally-issued information requests from the EPA. The EPA is required to finalize the rule by April 2014; however, because the rule has yet to be finalized, we cannot predict the impact it may have on our operations or consolidated financial results, but it could be material.

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. In 2010, the EPA proposed a rule to regulate CCBs at the federal level, which we believe might impair our ability to recycle ash or require additional CCB handling, processing and storage equipment, or both. The EPA has agreed, subject to court approval, to issue a final rule in 2014. While we cannot at this time estimate the impact and costs associated with future regulations of CCBs, we believe the impact on our operations and consolidated financial results could be material.

Renewable Energy Standard

Kansas law mandates that we maintain a minimum amount of renewable energy sources. Through 2015, net renewable generation capability must be 10% of the average peak retail demand for the three prior years, subject to limited exceptions. This requirement increases to 15% for years 2016 through 2019 and 20% for 2020 and thereafter. With our existing wind generation facilities, supply contracts and renewable energy credits, we are able to satisfy the net renewable generation requirement through 2015. With our agreement to purchase an additional 200 MW of installed design capcaity from a wind generation facility beginning in late 2016, we expect to meet the increased requirements through 2020. If we are unable to meet future requirements, our operations and consolidated financial results could be adversely impacted.

Environmental Costs

As discussed above, environmental laws and regulations affecting our operations are evolving and becoming more stringent. As a result, we are making and will continue to make significant capital and operating expenditures to reduce regulated emissions. The amount of these expenditures could change materially depending on the timing and nature of required investments, the specific outcomes resulting from existing regulations, new regulations, legislation and the manner in which we operate our plants. The degree to which we will need to reduce certain emissions and the timing of when such emissions controls may be required is uncertain. Additionally, our ability to access capital markets and the availability of materials, equipment and contractors may affect the timing and amount of these capital investments.

We are not allowed to use the ECRR to collect approximately $610.0 million of the projected capital investment associated with environmental upgrades at La Cygne. 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 and to reflect cost reductions elsewhere. The new prices are expected to increase our annual retail revenues by approximately $30.7 million. To change our prices to collect increased operating and maintenance costs, we must file a general rate review with the KCC.

Our estimated capital expenditures associated with environmental improvements for 2014-2016 appear in the following table. We prepare these estimates for planning purposes and revise them from time to time.

Year	Total
	(In Thousands)
2014	$ 237,000
2015	112,000
2016	21,900
Total	$ 370,900

In addition to the capital investment, in the event we install new equipment, such equipment may cause us to incur significant increases in annual operating and maintenance expenses and may reduce the net production, reliability and availability of the plants. Furthermore, enhancements to our power plants, even if they result in greater efficiency, can trigger a new source review, which could require additional control equipment. In order to change our prices to recognize increased operating and maintenance costs, we must file a general rate review with the KCC.

EPA Consent Decree

As part of a 2010 settlement of a lawsuit filed by the Department of Justice on behalf of the EPA, we are installing selective catalytic reduction (SCR) equipment on one of three JEC coal units by the end of 2014, which we estimate will cost approximately $230.0 million. We are installing less expensive NOx reduction equipment on the other two units to satisfy other terms of the settlement. We plan to complete these projects in 2014 and recover the costs to install these systems through our ECRR, but such recovery remains subject to the approval of our regulators.

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 believe we have appropriate measures in place to ensure the safety and health of our employees and to monitor compliance with such laws and regulations.

Information Technology

Safeguarding information technology networks and systems is important to our business. There are risks associated with the unauthorized access, theft or accidental release of electronic data, which may result in the misappropriation or corruption of our information or cause operational disruptions. We believe these risks are getting increasingly larger and more sophisticated. We believe that we have taken appropriate measures to secure our information infrastructure from attacks or breaches and from accidental release of information, but notwithstanding such measures, the increasing sophistication of potential attacks may result in remaining vulnerabilities. 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 18, 2014, we had 2,302 employees. In 2013, we negotiated a contract extension with Locals 304 and 1523 of the International Brotherhood of Electrical Workers that extends through June 30, 2017. The contract covers 1,256 employees as of February 18, 2014.

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	52	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)
Douglas R. Sterbenz	50	Executive Vice President and Chief Operating Officer (since July 2007)	
Greg A. Greenwood	48	Senior Vice President, Strategy (since August 2011)	**Westar Energy, Inc.** Vice President, Major Construction Projects (December 2009 to July 2011) Vice President, Generation Construction (August 2006 to December 2009)
Anthony D. Somma	50	Senior Vice President, Chief Financial Officer and Treasurer (since August 2011)	**Westar Energy, Inc.** Vice President, Treasurer (February 2009 to July 2011) Treasurer (August 2006 to February 2009)
Larry D. Irick	57	Vice President, General Counsel and Corporate Secretary (since February 2003)	
Kevin L. Kongs	51	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 market prices of our publicly traded 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 affect 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 and 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 formulae that track 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 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 affect on our consolidated financial results.

Our costs of compliance with environmental laws and regulations are significant, and the future costs of compliance with environmental laws and regulations could adversely affect our operations and consolidated financial results.

We are subject to extensive federal, state and local environmental statutes, rules 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.

Costs of compliance with environmental laws and regulations or fines or penalties resulting from non-compliance, if not recovered in our prices, could adversely affect 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 and 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 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Executive Summary — Current Trends — Environmental Regulation — Air Emissions" for additional information.

In addition, we combust large amounts of fossil fuels as we produce electricity. This results in significant emissions of CO_2 and other GHGs through the operation of our power plants. Federal legislation has been in the past and is expected in the future to be introduced in Congress to regulate the emission of GHGs and numerous states and regions have adopted programs to stabilize or reduce GHG emissions.

The EPA regulates GHGs under the Clean Air Act. Under regulations finalized in 2010, the EPA is regulating GHG emissions from certain stationary sources, such as power plants. Under the current regulations, any source that emits at least 75,000 tons per year of GHGs is required to have a Title V operating permit under the Clean Air Act. Sources that already have a Title V permit would have GHG provisions added to their permits upon renewal. Additionally, Prevention of Significant Deterioration Program permits for new major sources of GHG emissions and GHG sources that undergo major modifications are required to implement BACT for the control of GHG emissions. The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. These regulations could have a material impact on our operations or require us to

incur substantial costs. Additionally, in January 2014, the EPA re-proposed an NSPS that would limit CO_2 emissions for new coal and natural gas fueled electric generating units. This proposal is expected to become a final rule in 2014. We are currently evaluating the proposal and believe it could impact our future generation plans if it becomes a final rule. In addition, the EPA is also expected to propose in June 2014, a GHG NSPS for existing units that could have a material impact on our 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 recycle some of our ash production, principally by selling to the aggregate industry. In 2010, the EPA proposed a rule to regulate CCBs, which we believe might impair our ability to recycle ash or require additional CCB handling, processing and storage equipment, or both. The EPA has agreed, subject to court approval, to issue a final rule in 2014. While we cannot at this time estimate the impact and costs associated with future regulations of CCBs, we believe the impact 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 affect on our consolidated financial results.

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

Our operations are affected by economic conditions. Adverse general 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 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.

In the opposite, 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.

If an incident did occur at Wolf Creek, it could have a material affect 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.

In addition, in the event of an extended or unscheduled outage at Wolf Creek, we would be required to generate power from more costly generating units, purchase power in the open market to replace the power normally produced at Wolf Creek and have less power available for sale into the wholesale market. If we were unable to recover these costs in the prices we charge customers, such events would likely have an adverse impact on our consolidated financial results.

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 affected.

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 2014 through 2016 are approximately $2.1 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 or 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 and other related effects may have an adverse impact on 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 affect 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 affected.

Security breaches, criminal activity, terrorist attacks and other disruptions to our information technology infrastructure could directly or indirectly interfere with our operations, could expose us or our customers or employees to a risk of loss, and could expose us to liability, regulatory penalties, 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 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. Our technology networks and systems collect and store sensitive data including system 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 may be vulnerable to damage, disruptions or shutdowns due to attacks by hackers or breaches due to employee error or malfeasance, or other disruptions during software or hardware upgrades, telecommunication failures or natural disasters or other catastrophic events. The occurrence of any of these events could impact the reliability of our generation, transmission and distribution systems; could expose us, our customers or our employees to a risk of loss or misuse of information; and could result in legal claims or proceedings, liability or regulatory penalties against us, damage our reputation or otherwise harm our business. We cannot accurately assess the probability that a security breach may occur, despite the measures that we take to prevent such a breach, and we are unable to quantify the potential impact of such an event. 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.

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 or unplanned outages because of equipment failure, weather, transmission system disruption, operator error, contractor or subcontractor failure and other factors beyond our control. 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. Adoption of these technologies may increase because of advancements or government subsidies reducing the cost of generating electricity through these technologies to a level that is competitive with our current methods of generating electricity. There is also a perception that generating 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 because self-generating customers do not currently pay a share of the costs necessary to operate our transmission and distribution system. 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 Capacity (MW) By Owner		
Name/Location	Unit No.	Year Installed	Principal Fuel	Westar Energy	KGE	Total Company
Central Plains Wind Farm						
Wichita County, Kansas	[a]	2009	Wind	—	—	—
Emporia Energy Center:						
Emporia, Kansas						
Combustion Turbines	1	2008	Gas	45	—	45
	2	2008	Gas	45	—	45
	3	2008	Gas	44	—	44
	4	2008	Gas	46	—	46
	5	2008	Gas	157	—	157
	6	2009	Gas	153	—	153
	7	2009	Gas	156	—	156
Flat Ridge Wind Farm						
Barber County, Kansas	[a]	2009	Wind	1	—	1
Gordon Evans Energy Center:						
Colwich, Kansas						
Steam Turbines	1	1961	Gas	—	152	152
	2	1967	Gas	—	372	372
Combustion Turbines	1	2000	Gas	68	—	68
	2	2000	Gas	66	—	66
	3	2001	Gas	148	—	148
Hutchinson Energy Center:						
Hutchinson, Kansas						
Steam Turbine	4	1965	Gas	171	—	171
Combustion Turbines	1	1974	Gas	56	—	56
	2	1974	Gas	52	—	52
	3	1974	Gas	57	—	57
	4	1975	Diesel	71	—	71
Jeffrey Energy Center (92%):						
St. Marys, Kansas						
Steam Turbines	1 [b]	1978	Coal	517	144	661
	2 [b]	1980	Coal	515	143	658
	3 [b]	1983	Coal	520	144	664
La Cygne Station (50%):						
La Cygne, Kansas						
Steam Turbines	1 [b]	1973	Coal	—	368	368
	2 [c]	1977	Coal	—	341	341
Lawrence Energy Center:						
Lawrence, Kansas						
Steam Turbines	3	1954	Coal	49	—	49
	4	1960	Coal	107	—	107
	5	1971	Coal	374	—	374
Murray Gill Energy Center:						
Wichita, Kansas						
Steam Turbines	1	1952	Gas	—	37	37
	2	1954	Gas	—	48	48
	3	1956	Gas	—	93	93
	4	1959	Gas	—	90	90
Spring Creek Energy Center:						
Edmond, Oklahoma						
Combustion Turbines	1 [d]	2001	Gas	68	—	68
	2 [d]	2001	Gas	68	—	68
	3 [d]	2001	Gas	67	—	67
	4 [d]	2001	Gas	68	—	68
State Line (40%):						
Joplin, Missouri						
Combined Cycle	2-1 [b]	2001	Gas	64	—	64
	2-2 [b]	2001	Gas	65	—	65
	2-3 [b]	2001	Gas	72	—	72
Tecumseh Energy Center:						
Tecumseh, Kansas						
Steam Turbines	7	1957	Coal	72	—	72
	8	1962	Coal	130	—	130
Wolf Creek Generating Station (47%):						
Burlington, Kansas						
Nuclear	1 [b]	1985	Uranium	—	547	547
Total				4,092	2,479	6,571

[a] *Westar Energy owns Central Plains Wind Farm, which has an installed design capacity of 99 MW. Westar Energy owns 50% and purchases the other 50% of the generation from Flat Ridge Wind Farm pursuant to a purchase power agreement with BP Alternative Energy North. In total, it has an installed design capacity of 100 MW.*

[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."*

[d] *We acquired Spring Creek Energy Center in 2006.*

We own and have in service approximately 6,300 miles of transmission lines, approximately 24,000 miles of overhead distribution lines and approximately 4,700 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.

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

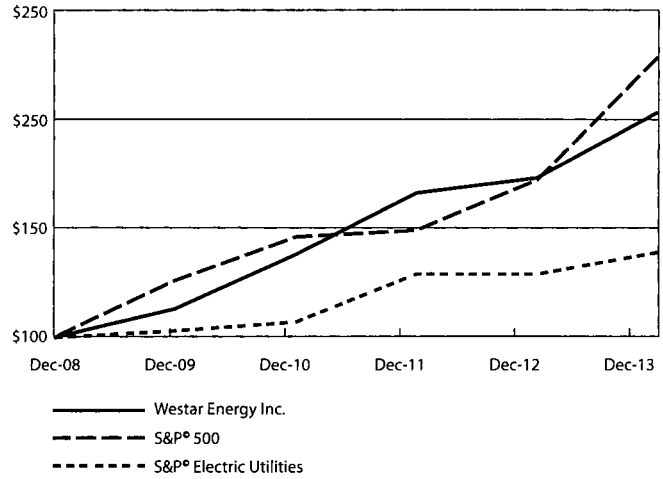
STOCK TRADING

Westar Energy's common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 18, 2014, Westar Energy had 19,436 common shareholders of record. For information regarding quarterly common stock price ranges for 2013 and 2012, 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, 2008, and ended on December 31, 2013, 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, 2008 with dividends reinvested



	Dec-2008	Dec-2009	Dec-2010	Dec-2011	Dec-2012	Dec-2013
Westar Energy Inc.	$100	$113	$138	$166	$173	$203
S&P® 500	$100	$126	$146	$149	$172	$228
S&P® Electric Utilities	$100	$103	$107	$129	$129	$139

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 2013, Westar Energy's board of directors declared four quarterly dividends of $0.34 per share, reflecting an annual dividend of $1.36 per share, compared to four quarterly dividends of $0.33 per share in 2012, reflecting an annual dividend of $1.32 per share. On February 26, 2014, Westar Energy's board of directors declared a quarterly dividend of $0.35 per share payable to shareholders on April 1, 2014. The indicated annual dividend rate is $1.40 per share.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31,	2013	2012	2011	2010	2009
			(In Thousands)		
Income Statement Data:					
Total revenues	$ 2,370,654	$ 2,261,470	$ 2,170,991	$ 2,056,171	$ 1,858,231
Net income[a]	300,863	282,462	236,180	208,624	141,330
Net income attributable to common stock	292,520	273,530	229,269	202,926	174,105
As of December 31,	**2013**	**2012**	**2011**	**2010**	**2009**
			(In Thousands)		
Balance Sheet Data:					
Total assets	$ 9,597,111	$ 9,265,231	$ 8,682,851	$ 8,079,638	$ 7,525,483
Long-term obligations[b]	3,495,292	3,124,831	2,818,030	2,808,560	2,610,315
Year Ended December 31,	**2013**	**2012**	**2011**	**2010**	**2009**
Common Stock Data:					
Basic earnings per share available for common stock[c]	$ 2.29	$ 2.15	$ 1.95	$ 1.81	$ 1.58
Diluted earnings per share available for common stock	2.27	2.15	1.93	1.80	1.58
Dividends declared per share	1.36	1.32	1.28	1.24	1.20
Book value per share	23.88	22.89	22.03	21.25	20.59
Average equivalent common shares outstanding (in thousands)[d][e]	127,463	126,712	116,891	111,629	109,648

[a] *The 2009 amount represents income from continuing operations.*

[b] *Includes long-term debt, net, current maturities of long-term debt, capital leases and, for 2010 through 2013, 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.*

[c] *We recorded basic EPS available for common stock from continuing operations of $1.28 in 2009 using the two-class method. See Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies-Earnings Per Share," for additional information regarding the two-class method.*

[d] *In 2010, Westar Energy issued and sold approximately 3.1 million shares of common stock realizing proceeds of $54.7 million.*

[e] *In 2011, Westar Energy issued and sold approximately 13.6 million shares of common stock realizing proceeds of $294.9 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 693,000 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 EPS for the years ended December 31, 2013 and 2012.

Year Ended December 31,	2013	2012	Change
	(Dollars In Thousands, Except Per Share Amounts)		
Net income attributable to common stock	$ 292,520	$ 273,530	$ 18,990
Earnings per common share, basic	2.29	2.15	0.14

Net income attributed to common stock and basic EPS for the year ended December 31, 2013, increased due primarily to higher prices and lower selling, general and administrative expenses. Lower electricity sales as a result of cooler weather and reduced demand for electricity served to partially offset the aforementioned increases. 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 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 and diverse energy supply portfolio. In doing so, we continue to make environmental upgrades to our coal-fired power plants, develop renewable generation, build and upgrade our electrical infrastructure, and develop systems and programs with regard to how our customers use energy.

Current Trends

Environmental Regulation

Environmental laws and regulations affecting our operations, which 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, continue to evolve and have become more stringent and costly over time. We have incurred and will continue to incur significant capital and other expenditures, and may potentially need to limit the use of some of our power plants, to comply with existing and new environmental laws and regulations. While certain of these costs are recoverable through the ECRR and ultimately we expect all such costs to be reflected in the prices we are allowed to charge, we cannot assure that all such costs will be recovered or that they will be recovered in a timely manner. See Note 13 of the Notes to Condensed Consolidated Financial Statements, "Commitments and Contingencies," for additional information regarding environmental laws and regulations.

Air Emissions

The operation of power plants results in emissions of mercury, acid gases and other air toxics. In 2012, the EPA's MATS for power plants became effective, replacing the prior federal CAMR and requiring significant reductions in mercury, acid gases and other emissions. We expect to be compliant with the new standards by April 2016 as approved by KDHE. We continue to evaluate the new standards and believe that our related investment will be approximately $17.0 million.

Greenhouse Gases

In January 2014, the EPA re-proposed a NSPS that would limit CO_2 emissions for new coal and natural gas fueled generating units. The re-proposal would limit CO_2 emissions to 1,000 lbs per MWh generated for larger natural gas units and 1,100 lbs per MWh generated for smaller natural gas units and coal units. Final regulations are expected later in 2014. The EPA was also directed to issue proposed standards addressing CO_2 emissions for modified, reconstructed and existing power plants by June 2014, issue final rules by June 2015, and require that states submit their implementation plans to the EPA no later than June 2016. We cannot at this time determine the impact of such proposals on our operations and consolidated financial results, but we believe the costs to comply could be material.

Under regulations known as the Tailoring Rule, the EPA regulates GHG emissions from certain stationary sources. The regulations are being implemented pursuant to two federal Clean Air Act programs which impose recordkeeping and monitoring requirements and also mandate the implementation of BACT for projects that cause a significant increase in GHG emissions (defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors). The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. We cannot at this time determine the impact of these regulations on our future operations and consolidated financial results, but we believe the costs to comply with the regulations could be material.

Regulation of Coal Combustion Byproducts

In the course of operating our coal generation plants, we produce CCBs, including fly ash, gypsum and bottom ash. We recycle some of our ash production, principally by selling to the aggregate industry. In 2010, the EPA proposed a rule to regulate CCBs, which we believe might impair our ability to recycle ash or require additional CCB handling, processing and storage equipment, or both. The EPA has agreed, subject to court approval, to issue a final rule in 2014. While we cannot at this time estimate the impact and costs associated with future regulations of CCBs, we believe the impact on our operations and consolidated financial results could be material.

National Ambient Air Quality Standards

Under the federal Clean Air Act, the EPA sets NAAQS for certain emissions considered harmful to public health and the environment, including two classes of PM, 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 EPA at five-year intervals. KDHE proposed to designate portions of the Kansas City area nonattainment for the eight-hour ozone standard. The EPA has not acted on KDHE's proposed designation of the Kansas City area and it is uncertain when, or if, such a designation might occur. The Wichita area also exceeded the eight-hour ozone standard and could be designated nonattainment in the future potentially impacting our operations.

In September 2011, the President instructed the EPA not to implement its more stringent 2008 Ozone Standard since a new NAAQS for ozone was due to be proposed in 2013 and finalized in 2014. We are waiting on this new standard and cannot at this time predict the impact it may have on our operations, but it could be material.

In December 2012, the EPA strengthened an existing NAAQS for one class of PM. By the end of 2014, the EPA anticipates making final attainment/nonattainment designations under this rule and expects to issue a final implementation rule. We are currently evaluating the rule, however, we cannot at this time predict the impact it may have on our operations or consolidated financial results, but it could be material.

In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. We continue to communicate with our regulators regarding these standards and are currently evaluating what impact this could have on our operations and consolidated financial results. If we are required to install additional equipment to control emissions at our facilities, the revised NAAQS could have a material impact on our operations and 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 are expected to be issued by the EPA in 2014. Although we cannot at this time determine the timing or impact of compliance with any new regulations, more stringent regulations could have a material impact on our operations and consolidated financial results.

In 2011, the EPA issued a proposed rule that would increase the requirements for cooling water intake structures at power plants over concerns about impacts to aquatic life. We are currently evaluating the proposed rule as well as recent nationally-issued information requests from the EPA. The EPA is required to finalize the rule by April 2014; however, because the rule has yet to be finalized, we cannot predict the impact it may have on our operations or consolidated financial results, but it could be material.

Renewable Energy Standard

Kansas law mandates that we maintain a minimum amount of renewable energy sources. Through 2015, net renewable generation capacity must be 10% of the average peak retail demand for the three prior years, subject to limited exceptions. This requirement increases to 15% for years 2016 through 2019 and 20% for 2020 and thereafter. With our existing wind generation facilities, supply contracts and renewable energy credits, we are able to satisfy the net renewable generation requirement through 2015. With our agreement to purchase an additional 200 MW of installed design capacity from a wind generation facility beginning in late 2016, we expect to meet the increased requirements through 2020. If we are unable to meet future requirements, our operations and consolidated financial results could be adversely impacted.

Regulation of Nuclear Generating Station

Additional regulation of Wolf Creek resulting from NRC oversight of the plant's performance or from changing regulations generally, including those that could potentially result from natural disasters or any event that might occur at any nuclear power plant anywhere in the world, may result in increased operating and capital expenditures. We cannot estimate the cost associated with such increases, but they could be material to our operations and consolidated financial results.

We expect future increases in operating costs due to increased NRC oversight and efforts to comply with new industry-wide regulations adopted by the NRC in 2012. Future extended or unscheduled shutdowns of Wolf Creek could cause us to purchase replacement power, rely more heavily on our other generating units and reduce amounts of power available for us to sell in the wholesale market.

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. 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,	2013	2012	2011
		(In Thousands)	
Borrowed funds	$ 11,706	$ 10,399	$ 5,589
Equity funds	14,143	11,706	5,550
Total	$ 25,849	$ 22,105	$ 11,139
Average AFUDC Rates	4.8%	5.0%	3.6%

We expect AFUDC for both borrowed funds and equity funds to fluctuate over the next several years as we execute our capital expenditure program.

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 expect the number of outstanding shares of Westar Energy common stock to increase through 2015 as we issue additional shares previously priced through forward sales agreements to fund our capital expenditure program. See Note 16 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock," for additional information regarding our share issuances.

Customer Growth and Usage

Residential customer additions have slowed and electricity demand is stable to slightly declining due principally to the effects of the economic downturn and energy efficiency measures. Absent an economic recovery to conditions similar to those preceding the downturn, we believe such customer additions will continue to be significantly lower than historical levels. In addition, with the numerous energy efficiency policy initiatives promulgated through federal, state and local governments, as well as industry, we believe customers will continue to adopt more energy efficiency and conservation measures which will suppress the rate of demand for electricity.

2014 Outlook

In 2014, we expect to maintain our current business strategy and regulatory approach. Subject to regulatory approvals, we anticipate annualized price increases of approximately $50.0 million from formulae that track changes in certain of our costs, as well as a $30.7 million general price increase authorized by the KCC in November 2013. Assuming normal weather in line with the historical average, we expect 2014 retail electricity sales to be between about 0.5% to 1.0% higher than weather-normalized 2013 sales.

In addition, we anticipate increased operating and maintenance expenses, including maintenance costs for our power plants, and higher selling, general and administrative expenses. SPP transmission expense and property taxes are increasing at a much higher rate than inflation and are offset with higher revenues pursuant to our regulatory mechanisms. To help fund our capital spending as provided under "— Future Cash Requirements" below, we plan to utilize short-term borrowings and we expect to issue common stock to settle forward sale transactions.

In March 2014, the SPP is expected to launch an IM similar to other organized power markets currently operating in other RTOs. As a result, we expect an increase in revenues and a corresponding increase in fuel and purchased power expense. Further, additional products may result in increased derivative activity, currently presented in other assets and liabilities, for which we will receive regulatory treatment.

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 currently 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. Were we to 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, 2013, we had recorded regulatory assets currently subject to recovery in future prices of approximately $755.4 million and regulatory liabilities of $329.6 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 applicable 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, 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	$ 70,159	$ 6,721
	0.5% increase	(63,319)	(6,234)
Salary scale	0.5% decrease	(17,359)	(3,392)
	0.5% increase	17,686	3,491
Rate of return on plan assets	0.5% decrease	—	3,359
	0.5% increase	—	(3,359)

[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	$ 8,174	$ 436
	0.5% increase	(7,702)	(446)
Rate of return on plan assets	0.5% decrease	—	521
	0.5% increase	—	(519)
Annual medical trend	1.0% decrease	(1,804)	(261)
	1.0% increase	1,996	292

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

Revenue Recognition

Electricity Sales

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 $60.1 million as of December 31, 2013 and $62.5 million as of December 31, 2012.

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 of the Notes to Consolidated Financial Statements, "Taxes," for additional detail on our accounting for income taxes.

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, 2013 and 2012, we have recorded AROs of $160.7 million and $152.6 million, respectively. For additional information on our legal AROs, see Note 14 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations."

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, 2013 and 2012, we had $114.1 million and $129.0 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability.

Contingencies and Litigation

We are currently involved in certain legal proceedings and have estimated the probable cost for the resolution of these claims. 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 13 and 15 of the Notes to Consolidated Financial Statements, "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 for lighting public streets and highways, net of revenue subject to refund.

Wholesale: Sales of electricity to electric cooperatives, municipalities and other electric utilities, the prices for which are either based on cost or prevailing market prices as prescribed by FERC authority. Margins realized from these sales serve to offset retail prices through either the RECA or at the time of our next general rate case.

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.

2013 Compared to 2012

Below we discuss our operating results for the year ended December 31, 2013, compared to the results for the year ended December 31, 2012. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

Year Ended December 31,	2013	2012	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 728,852	$ 714,562	$ 14,290	2.0
Commercial	667,106	640,654	26,452	4.1
Industrial	374,825	368,909	5,916	1.6
Other retail	8,939	(5,845)	14,784	252.9
Total Retail Revenues	1,779,722	1,718,280	61,442	3.6
Wholesale	348,239	316,353	31,886	10.1
Transmission[a]	210,281	193,797	16,484	8.5
Other	32,412	33,040	(628)	(1.9)
Total Revenues	2,370,654	2,261,470	109,184	4.8
OPERATING EXPENSES:				
Fuel and purchased power	634,797	589,990	44,807	7.6
SPP network transmission costs	178,604	166,547	12,057	7.2
Operating and maintenance	359,060	342,055	17,005	5.0
Depreciation and amortization	272,593	270,464	2,129	0.8
Selling, general and administrative	224,133	226,012	(1,879)	(0.8)
Taxes other than income tax	122,282	104,269	18,013	17.3
Total Operating Expenses	1,791,469	1,699,337	92,132	5.4
INCOME FROM OPERATIONS	579,185	562,133	17,052	3.0
OTHER INCOME (EXPENSE):				
Investment earnings	10,056	7,411	2,645	35.7
Other income	35,609	35,378	231	0.7
Other expense	(18,099)	(19,987)	1,888	9.4
Total Other Income	27,566	22,802	4,764	20.9
Interest expense	182,167	176,337	5,830	3.3
INCOME BEFORE INCOME TAXES	424,584	408,598	15,986	3.9
Income tax expense	123,721	126,136	(2,415)	(1.9)
NET INCOME	300,863	282,462	18,401	6.5
Less: Net income attributable to noncontrolling interests	8,343	7,316	1,027	14.0
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY, INC.	292,520	275,146	17,374	6.3
Preferred dividends	—	1,616	(1,616)	(100.0)
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 292,520	$ 273,530	$ 18,990	6.9
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY	$ 2.29	$ 2.15	$ 0.14	6.5
DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY	$ 2.27	$ 2.15	$ 0.12	5.6

[a] *Reflects revenue from an SPP network transmission tariff corresponding to our SPP network transmission costs. These costs, less administration fees of $39.1 million and $27.2 million, were returned to us as revenue in 2013 and 2012, respectively.*

Rate Case 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 are expected to increase our annual retail revenues by approximately $30.7 million.

In April 2012, the KCC issued an order authorizing higher revenues to recover higher expenses primarily for increased tree trimming to enhance reliability and increased pension costs resulting from the consequences of the 2008 financial crisis and subsequent low interest rate environment in accordance with the regulatory mechanism in place to account for such pension costs. As a result of this order, we expect selling, general and administrative expense to increase $32.1 million and the cost of operating and maintaining our distribution system to increase $10.9 million on an annualized basis. In addition, we revised our depreciation rates to reflect changes in the estimated useful lives of some of our assets. The change in estimate will decrease annual depreciation expense by $43.6 million. However, decreased depreciation expense as a result of lower depreciation rates will be offset by additional depreciation related to additions to property, plant and equipment. Because the aforementioned changes were implemented shortly after the KCC issued its order, our 2012 consolidated financial results do not reflect the full annual impact of the changes.

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, 2013 and 2012.

Year Ended December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Revenues	$ 2,370,654	$ 2,261,470	$ 109,184	4.8
Less: Fuel and purchased power expense	634,797	589,990	44,807	7.6
SPP network transmission costs	178,604	166,547	12,057	7.2
Gross Margin	$ 1,557,253	$ 1,504,933	$ 52,320	3.5

The following table reflects changes in electricity sales for the years ended December 31, 2013 and 2012. 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,	2013	2012	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,523	6,684	(161)	(2.4)
Commercial	7,480	7,581	(101)	(1.3)
Industrial	5,407	5,588	(181)	(3.2)
Other retail	86	85	1	1.2
Total Retail	19,496	19,938	(442)	(2.2)
Wholesale	8,593	7,719	874	11.3
Total	28,089	27,657	432	1.6

Gross margin increased due primarily to higher retail revenues that were the result of higher prices offset partially by lower retail electricity sales. The lower retail electricity sales were attributable principally to cooler summer weather, which particularly impacted residential and commercial electricity sales. As measured by cooling degree days, 2013 was 23% cooler than the prior year. Contributing also to the decrease in retail sales was the reduced demand, primarily from several large industrial customers.

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, 2013 and 2012.

Year Ended December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Gross margin	$ 1,557,253	$ 1,504,933	$ 52,320	3.5
Less: Operating and maintenance expense	359,060	342,055	17,005	5.0
Depreciation and amortization expense	272,593	270,464	2,129	0.8
Selling, general and administrative expense	224,133	226,012	(1,879)	(0.8)
Taxes other than income tax	122,282	104,269	18,013	17.3
Income from operations	$ 579,185	$ 562,133	$ 17,052	3.0

Operating Expenses and Other Income and Expense Items

Year Ended December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Operating and maintenance expense	$ 359,060	$ 342,055	$ 17,005	5.0

Operating and maintenance expense increased due principally to:

- higher costs for tree trimming, pursuant to authorized rate recovery, and other distribution reliability activities of $11.8 million; and
- higher costs at Wolf Creek of $5.0 million, due principally to higher amortization of refueling outage costs and recognition of costs incurred during an unscheduled maintenance outage in 2013.

Year Ended December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Depreciation and amortization expense	$ 272,593	$ 270,464	$ 2,129	0.8

Depreciation and amortization expense increased due to additional depreciation expense resulting primarily from increased plant additions at our power plants, including air quality controls, and the addition of transmission facilities. Partially offsetting this increase was a result of our having reduced depreciation rates in mid 2012 to reflect changes in the estimated useful lives of some of our assets.

Year Ended December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Selling, general and administrative expense	$ 224,133	$ 226,012	$ (1,879)	(0.8)

Selling, general and administrative expense decreased due primarily to:

- lower post-retirement and other employee benefit costs of $8.6 million due principally to restructuring insurance contracts; and,
- lower labor cost of $2.3 million, which in part reflects expenses recorded in 2012 related to sustainable cost reduction activities; however,
- partially offsetting these decreases were higher pension costs of $12.3 million, most of which were offset with higher revenues. These increased pension cost were principally a consequence of the 2008 financial market downturn and the subsequent low interest rate environment.

Year Ended December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Taxes other than income tax	$ 122,282	$ 104,269	$ 18,013	17.3

Taxes other than income tax increased due primarily to an $18.2 million increase in property taxes, which are offset in retail revenues.

Year Ended December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Investment earnings	$ 10,056	$ 7,411	$ 2,645	35.7

Investment earnings increased due principally to:

- $1.2 million increase in earnings from our investment in Prairie Wind Transmission, LLC; and,
- $1.4 million of additional gains on investments in a trust to fund retirement benefits.

Year Ended December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Interest expense	$ 182,167	$ 176,337	$ 5,830	3.3

Interest expense increased due to our recording $10.5 million in interest principally related to additional debt issued to fund capital investment. Partially offsetting this increase was a $2.2 million decrease of interest expense on long-term debt of VIEs and a $1.3 million decrease for capitalized interest.

2012 COMPARED TO 2011

Below we discuss our operating results for the year ended December 31, 2012, compared to the results for the year ended December 31, 2011. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

Year Ended December 31,	2012	2011	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 714,562	$ 693,388	$ 21,174	3.1
Commercial	640,654	604,626	36,028	6.0
Industrial	368,909	347,881	21,028	6.0
Other retail	(5,845)	(8,964)	3,119	34.8
Total Retail Revenues	1,718,280	1,636,931	81,349	5.0
Wholesale	316,353	346,948	(30,595)	(8.8)
Transmission[a]	193,797	154,569	39,228	25.4
Other	33,040	32,543	497	1.5
Total Revenues	2,261,470	2,170,991	90,479	4.2
OPERATING EXPENSES:				
Fuel and purchased power	589,990	630,793	(40,803)	(6.5)
SPP network transmission costs	166,547	132,164	34,383	26.0
Operating and maintenance	342,055	332,989	9,066	2.7
Depreciation and amortization	270,464	285,322	(14,858)	(5.2)
Selling, general and administrative	226,012	184,695	41,317	22.4
Taxes other than income tax	104,269	92,599	11,670	12.6
Total Operating Expenses	1,699,337	1,658,562	40,775	2.5
INCOME FROM OPERATIONS	562,133	512,429	49,704	9.7
OTHER INCOME (EXPENSE):				
Investment earnings	7,411	9,301	(1,890)	(20.3)
Other income	35,378	8,652	26,726	308.9
Other expense	(19,987)	(18,398)	(1,589)	(8.6)
Total Other Income (Expense)	22,802	(445)	23,247	[b]
Interest expense	176,337	172,460	3,877	2.2
INCOME BEFORE INCOME TAXES	408,598	339,524	69,074	20.3
Income tax expense	126,136	103,344	22,792	22.1
NET INCOME	282,462	236,180	46,282	19.6
Less: Net income attributable to noncontrolling interests	7,316	5,941	1,375	23.1
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY, INC.	275,146	230,239	44,907	19.5
Preferred dividends	1,616	970	646	66.6
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 273,530	$ 229,269	$ 44,261	19.3
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY	$ 2.15	$ 1.95	$ 0.20	10.3
DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY	$ 2.15	$ 1.93	$ 0.22	11.4

[a] *Reflects revenue from an SPP network transmission tariff corresponding to our SPP network transmission costs. These costs, less administration fees of $27.2 million and $18.6 million, respectively, were returned to us as revenue.*

[b] *Change greater than 1,000%.*

Gross Margin

The following table summarizes our gross margin for the years ended December 31, 2012 and 2011.

Year Ended December 31,	2012	2011	Change	% Change
	(Dollars In Thousands)			
Revenues	$ 2,261,470	$ 2,170,991	$ 90,479	4.2
Less: Fuel and purchased power expense	589,990	630,793	(40,803)	(6.5)
SPP network transmission costs	166,547	132,164	34,383	26.0
Gross Margin	$ 1,504,933	$ 1,408,034	$ 96,899	6.9

The following table reflects changes in electricity sales for the years ended December 31, 2012 and 2011. 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,	2012	2011	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,684	6,986	(302)	(4.3)
Commercial	7,581	7,573	8	0.1
Industrial	5,588	5,589	(1)	(a)
Other retail	85	88	(3)	(3.4)
Total Retail	19,938	20,236	(298)	(1.5)
Wholesale	7,719	8,215	(496)	(6.0)
Total	27,657	28,451	(794)	(2.8)

[a] *Change less than 0.1%*

Gross margin increased due primarily to higher retail revenues that were the result of higher prices offset partially by lower retail electricity sales. The lower retail electricity sales were attributable principally to moderate weather, which particularly impacted residential electricity sales. In 2012, cooling degree days were similar to 2011; however, cooling degree days during the third quarter of 2012 were 9% lower than the same period of 2011.

The following table reconciles income from operations with gross margin for the years ended December 31, 2012 and 2011.

Year Ended December 31,	2012	2011	Change	% Change
	(Dollars In Thousands)			
Gross margin	$ 1,504,933	$ 1,408,034	$ 96,899	6.9
Less: Operating and maintenance expense	342,055	332,989	9,066	2.7
Depreciation and amortization expense	270,464	285,322	(14,858)	(5.2)
Selling, general and administrative expense	226,012	184,695	41,317	22.4
Taxes other than income tax	104,269	92,599	11,670	12.6
Income from operations	$ 562,133	$ 512,429	$ 49,704	9.7

Operating Expenses and Other Income and Expense Items

Year Ended December 31,	2012	2011	Change	% Change
	(Dollars In Thousands)			
Operating and maintenance expense	$ 342,055	$ 332,989	$ 9,066	2.7

Operating and maintenance expense increased due principally to:

- higher costs for tree trimming, pursuant to authorized rate recovery, and other electrical system reliability activities of $5.9 million; and
- higher costs at Wolf Creek of $4.6 million, which were the result primarily of maintenance costs incurred during an unscheduled outage.

Year Ended December 31,	2012	2011	Change	% Change
	(Dollars In Thousands)			
Depreciation and amortization expense	$ 270,464	$ 285,322	$ (14,858)	(5.2)

Depreciation and amortization expense decreased as a result of our having reduced depreciation rates to reflect changes in the estimated useful lives of some of our assets. Partially offsetting this decrease was additional depreciation expense associated primarily with additions at our power plants, including air quality controls, and the addition of transmission facilities.

Year Ended December 31,	2012	2011	Change	% Change
	(Dollars In Thousands)			
Selling, general and administrative expense	$ 226,012	$ 184,695	$ 41,317	22.4

Selling, general and administrative expense increased due primarily to:

- our having reversed $22.0 million of previously accrued liabilities in 2011 as a result of settling litigation;
- higher pension and other employee benefit costs of $20.2 million pursuant to authorized rate recovery;
- our having recorded $4.5 million of expense as a result of sustainable cost reduction activities; and
- a $2.1 million increase in the amortization of previously deferred amounts associated with various energy efficiency programs, which we recover in retail revenues; however,
- partially offsetting these increases was a $9.4 million decrease in legal fees that was the result principally of arbitration and litigation that occurred in 2011.

Year Ended December 31,	2012	2011	Change	% Change
	(Dollars In Thousands)			
Taxes other than income tax	$ 104,269	$ 92,599	$ 11,670	12.6

Taxes other than income tax increased due primarily to a $9.2 million increase in property taxes, which is offset in retail revenues.

Year Ended December 31,	2012	2011	Change	% Change
	(Dollars In Thousands)			
Investment earnings	$ 7,411	$ 9,301	$ (1,890)	(20.3)

Investment earnings decreased due principally to:

- our having recorded a $7.2 million gain on the sale of a non-utility investment in 2011; however,
- partially offsetting this item was our having recorded $4.5 million of additional gains on investments in a trust to fund retirement benefits and a $1.7 million increase in earnings from our investment in Prairie Wind Transmission, LLC.

Year Ended December 31,	2012	2011	Change	% Change
	(Dollars In Thousands)			
Other income	$ 35,378	$ 8,652	$ 26,726	308.9

Other income increased due principally to:

- our having recorded an additional $17.4 million in COLI (corporate-owned life insurance) benefits;
- a $6.2 million increase in equity AFUDC, which reflects more construction activity; and
- our having recorded an additional $3.1 million related to the sale of oil inventory.

Year Ended December 31,	2012	2011	Change	% Change
	(Dollars In Thousands)			
Income tax expense	$ 126,136	$ 103,344	$ 22,792	22.1

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

Financial Condition

A number of factors affected amounts recorded on our balance sheet as of December 31, 2013, compared to December 31, 2012.

As of December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Fuel inventory and supplies	$ 239,511	$ 249,016	$ (9,505)	(3.8)

Fuel inventory and supplies decreased due principally to a $16.7 million decrease in coal inventory, due to a price reduction in the cost of coal and reduced transportation costs. This decrease was partially offset by a $6.8 million increase in materials and supplies as a result of higher inventory replacement costs as well as materials purchased for spring 2014 outages.

As of December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Property, plant and equipment, net	$ 7,551,916	$ 7,013,765	$ 538,151	7.7

Property, plant and equipment, net of accumulated depreciation, increased due primarily to additions at our power plants, including air quality controls, and the addition of transmission facilities.

As of December 31,	2013	2012	Change	% Change
	(Dollars In Thousands)			
Property, plant and equipment of variable interest entities, net	$ 296,626	$ 321,975	$ (25,349)	(7.9)

Property, plant and equipment of variable interest entities, net of accumulated depreciation, decreased due to deconsolidating a rail car lease as discussed in Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," and normal depreciation of these assets.

As of December 31,	2013	2012	Change	% Change
		(Dollars In Thousands)		
Regulatory assets	$ 755,414	$ 1,002,672	$ (247,258)	(24.7)
Regulatory liabilities	329,556	323,175	6,381	2.0
Net regulatory assets	$ 425,858	$ 679,497	$ (253,639)	(37.3)

Total regulatory assets decreased due primarily to the following reasons:

- a $265.1 million decrease in deferred employee benefit costs, due primarily to decreased pension and post-retirement benefit obligations as a result of increases in the discount rates used to calculate our and Wolf Creek's benefits obligations;
- a $9.6 million decrease in amounts previously deferred for storm costs;
- a $5.3 million decrease in amounts due from customers for future income taxes; and
- a $4.4 million decrease in amounts deferred for energy effciency costs; however,
- partially offsetting decreases were a $17.9 million, $14.9 million and $12.7 million increase in amounts deferred for fuel expense, for the Wolf Creek outage and for property taxes, respectively.

Regulatory liabilities increased due primarily to a $24.9 million increase in the fair value of the NDT and an $8.3 million increase in other post-retirement costs. Partially offsetting this increase was a $14.8 million decrease in amounts collected but not yet spent to dispose of plant assets.

As of December 31,	2013	2012	Change	% Change
		(Dollars In Thousands)		
Short-term debt	$ 134,600	$ 339,200	$ (204,600)	(60.3)

Short-term debt decreased due to decreases in issuances of commercial paper. Proceeds from issuances of long-term debt were used to repay short-term debt, which had been used primarily to purchase capital equipment, to redeem bonds and for working capital and general corporate purposes.

As of December 31,	2013	2012	Change	% Change
		(Dollars In Thousands)		
Current maturities of long-term debt	$ 250,000	$ —	$ 250,000	
Long-term debt, net	2,968,958	2,819,271	149,687	5.3
Total long-term debt	$ 3,218,958	$ 2,819,271	$ 399,687	14.2

Total long-term debt increased due to the issuance of $500.0 million principal amount of first mortgage bonds. This increase was partially offset by our redemption of two pollution control bond issues with an aggregate principal amount of $100.0 million. Both the issuance and redemptions are further discussed in Note 9 of the Notes to Consolidated Financial Statements, "Long-Term Debt."

As of December 31,	2013	2012	Change	% Change
		(Dollars In Thousands)		
Current maturities of long-term debt of variable interest entities	$ 27,479	$ 25,942	$ 1,537	5.9
Long-term debt of variable interest entities	194,802	222,743	(27,941)	(12.5)
Total long-term debt of variable interest entities	$ 222,281	$ 248,685	$ (26,404)	(10.6)

Total long-term debt of variable interest entities decreased due principally to the VIEs that hold the JEC and La Cygne leasehold interests having made principal payments totaling $25.4 million.

As of December 31,	2013	2012	Change	% Change
		(Dollars In Thousands)		
Deferred income tax liabilities	$ 1,361,418	$ 1,197,837	$ 163,581	13.7

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,	2013	2012	Change	% Change
		(Dollars In Thousands)		
Accrued employee benefits	$ 331,558	$ 564,870	$ (233,312)	(41.3)

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 benefits obligations.

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. For additional information on our future cash requirements, see "— Future Cash Requirements" below.

In 2014, 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 "— Operating Results" above, economic conditions, regulatory actions, compliance with environmental regulations and conditions in the capital markets.

Capital Structure

As of December 31, 2013 and 2012, our capital structure, excluding short-term debt, was as follows:

As of December 31,	2013	2012
Common equity	47%	49%
Noncontrolling interests	<1%	<1%
Long-term debt, including VIEs	53%	51%

Short-Term Borrowings

In 2011, Westar Energy entered into 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 repay borrowings under Westar Energy's revolving credit facilities, for working capital and/or for other general corporate purposes. As of February 18, 2014, Westar Energy had issued $177.8 million of commercial paper.

Westar Energy has two revolving credit facilities in the amounts of $730.0 million and $270.0 million. In July 2013, Westar Energy extended the term of the $730.0 million facility to September 2017, and in February 2014, Westar Energy extended the term of the $270.0 million credit facility to February 2017, provided that $20.0 million of this facility will terminate in February 2016. As long as there is no default under the facility, 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 18, 2014, no amounts were borrowed and $18.5 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, 2013, our ratio was 53%. 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

We have $250.0 million in outstanding aggregate principal amount of first mortgage bonds that are due July 1, 2014. We expect to issue additional long-term debt to redeem those bonds before the maturity date thereof.

In August 2013, Westar Energy issued $250.0 million principal amount of first mortgage bonds bearing stated interest of 4.625% and maturing in September 2043.

In June 2013, KGE redeemed two pollution control bond series with an aggregate principal amount of $100.0 million and stated interest rates of 5.60% and 6.00%.

In March 2013, Westar Energy issued $250.0 million principal amount of first mortgage bonds bearing stated interest of 4.10% and maturing in April 2043. Proceeds from these issuances were used to repay short-term debt, which had been used primarily to purchase capital equipment, to redeem bonds and for working capital and general corporate purposes.

As of December 31, 2013, we had $121.9 million of variable rate, tax-exempt bonds. 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.

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, 2013, approximately $505.3 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 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, 2013, approximately $1.1 billion principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

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, 2013.

Impact of Credit Ratings on Debt Financing

Moody's Investors Service (Moody's), Standard & Poor's Ratings Services (S&P) and Fitch Ratings (Fitch) 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.

In January 2014, Moody's upgraded its ratings for Westar Energy and KGE first mortgage bonds to A2 from A3. In February 2013, S&P revised its criteria for rating utility first mortgage bonds and, as a result, upgraded its ratings for Westar Energy and KGE first mortgage bonds/senior secured debt to A- from BBB+. Additionally, in April 2013, S&P affirmed its ratings for Westar Energy and KGE and raised its outlook to positive from stable.

As of February 18, 2014, 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	Positive
Fitch	A-	A-	F2	Stable

Common and Preferred Stock

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, 2013, Westar Energy had 128.3 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 the agreements. Westar Energy must settle such transactions within 24 months.

In March 2013, Westar Energy entered into a new, three-year sales agency financing agreement and master forward sale confirmation with a bank, similar to the sales agency financing agreement and master forward sale confirmation entered into in April 2010. 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 March 2013 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. Westar Energy must settle the forward sale transactions within 18 months of the date each transaction is entered.

In April 2010, Westar Energy entered into a three-year Sales Agency Financing Agreement and 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. Under the terms of the Sales Agency Financing Agreement, Westar Energy could offer and sell shares of its common stock from time to time through the broker dealer subsidiary, as agent. The broker dealer received a commission equal to 1% of the sales price of all shares sold under the agreement. In addition, under the terms of the Sales Agency Financing Agreement and forward sale agreement, Westar Energy could 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 broker dealer. Westar Energy was required to settle the forward sale transactions within 18 months of the date each transaction was entered. In 2011 and 2010, Westar Energy entered into and settled forward sale transactions with respect to an aggregate of approximately 5.4 million shares of common stock for proceeds of approximately $118.3 million.

During 2013 and 2012, Westar Energy entered into additional forward sale transactions with respect to an aggregate of approximately 2.5 million and 1.8 million shares of common stock respectively, under the March 2013 and April 2010 agreements. During 2013, Westar Energy settled 1.1 million shares, resulting in 3.1 million shares under the March 2013 and April 2010 agreements that had not settled as of December 31, 2013. In February 2014, Westar Energy settled 0.3 million shares with a physical settlement amount of approximately $9.2 million.

The forward sale transactions are entered into at market prices; therefore, the forward sale agreements have no initial fair value. Westar Energy does not receive any proceeds from the sale of common stock under the forward sale agreements until transactions are settled. Upon settlement, Westar Energy will record the forward sale agreements within equity. Except in specified circumstances or events that would require physical share settlement, Westar Energy is able to elect to settle any forward sale transactions by means of physical share, cash or net share settlement, and is also able to elect to settle the forward sale transactions in whole, or in part, earlier than the stated maturity dates. Currently, Westar Energy anticipates settling the forward sale transactions through physical share settlement. The shares under the forward sale agreements are initially priced when the transactions are entered into and are subject to certain fixed pricing adjustments during the term of the agreements. Accordingly, assuming physical share settlement, Westar Energy's net proceeds from the forward sale transactions will represent the prices established by the forward sale agreements applicable to the time periods in which physical settlement occurs.

Assuming physical share settlement of the approximately 12.1 million shares associated with all forward sale transactions as of December 31, 2013, Westar Energy would have received aggregate proceeds of approximately $358.3 million based on a weighted average forward price of $29.73 per share.

Westar Energy used the proceeds from the issuance of common stock to repay short-term borrowings, with such borrowed amounts principally related to investments in capital equipment, as well as for working capital and general corporate purposes.

Preferred Stock Redemption

In May 2012, Westar Energy provided an irrevocable notice of redemption to holders of all of Westar Energy's preferred shares. Pursuant to Westar Energy's Articles of Incorporation, we deposited cash in a separate account to effect the redemption of all of our preferred stock outstanding. Payment was due to holders of the preferred shares effective July 1, 2012. The table below shows the redemption amounts for all series of preferred stock.

Rate	Shares	Principal Outstanding	Call Price	Premium	Total Cost to Reedem
		(Dollars In Thousands)			
4.50%	121,613	$ 12,161	108.0%	$ 973	$ 13,134
4.25%	54,970	5,497	101.5%	82	5,579
5.00%	37,780	3,778	102.0%	76	3,854
	214,363	$ 21,436		$ 1,131	$ 22,567

Summary of Cash Flows

Year Ended December 31,	2013	2012	2011
		(In Thousands)	
Cash flows from (used in):			
Operating activities	$ 702,803	$ 599,106	$ 462,696
Investing activities	(641,901)	(797,337)	(701,516)
Financing activities	(62,244)	200,521	241,431
Net (decrease) increase in cash and cash equivalents	$ (1,342)	$ 2,290	$ 2,611

Cash Flows from Operating Activities

Cash flows from operating activities increased $103.7 million in 2013 compared to 2012 due principally to our having received about $74.3 million more from retail and wholesale customers, our having paid approximately $40.9 million less for pension and post retirement contributions, our having paid $29.7 million in 2012 to settle treasury yield hedge transactions, and our receiving $9.6 million more in COLI death proceeds. Increases were offset partially by our having paid approximately $65.6 million more for the planned Wolf Creek refueling and maintenance outage.

The $136.4 million increase in 2012 compared to 2011 was due principally to our having paid approximately $100.9 million less for fuel and purchased power, our having received about $96.3 million more from retail customers and our having paid $56.3 million in 2011 to settle litigation. Increases were offset partially by our having received approximately $42.0 million less from wholesale customers, our having paid $29.7 million in 2012 to settle treasury yield hedge transactions, our having received $13.1 million less in income tax refunds and our having contributed $10.3 million more to pension and post-retirement benefit plans.

Cash Flows used in Investing Activities

Cash flows used in investing activities decreased $155.4 million from 2012 to 2013 due primarily to increased proceeds from investment in corporate owned life insurance of $114.1 million and decreased investment in property, plant and equipment of $30.1 million.

Cash flows used in investing activities increased $95.8 million from 2011 to 2012 due primarily to our having invested an additional $112.8 million in additions to property, plant and equipment, which was attributable principally to additions at our power plants, including air quality controls, and the addition of transmission facilities. The increased investment in 2012 was partially offset by our having received $32.2 million more in proceeds from our investment in COLI.

Cash Flows from (used in) Financing Activities

Cash flows from financing activities decreased $262.8 million in 2013 compared to 2012. The decrease was due primarily to our having borrowed $258.1 million less in short term debt and our having repaid $110.6 million more for borrowings against the cash surrender value of corporate owned life insurance. This decrease was partially offset by our having paid $120.6 million less to retire long-term debt.

The $40.9 million decrease in 2012 compared to 2011 was due principally to our having received $287.9 million less in proceeds from the issuance of common stock, which was attributable principally to our having issued shares in 2011 to settle forward transactions, and our having retired $220.2 million more of long-term debt due to favorable conditions in the capital markets. Contributing to the decrease was our having repaid $31.4 million more for borrowings against the cash surrender value of COLI, our having established a $22.6 million restricted cash account to fund the redemption of preferred stock and our having paid $19.9 million more for dividends as a result principally of our having increased

our common stock dividend from $1.28 per share in 2011 to $1.32 per share in 2012. Partially offsetting the decreases was our having received $541.4 million in proceeds from long-term debt issuances. The proceeds 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.

Future Cash Requirements

Our business requires significant capital investments. Through 2016, 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 for environmental projects at our coal-fired power plants, 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 2013 and anticipated capital expenditures, including costs of removal, for 2014 through 2016 are shown in the following table.

	Actual 2013	2014	2015	2016
	(In Thousands)			
Generation:				
Replacements and other	$ 201,395	$ 181,600	$ 173,100	$ 136,800
Environmental	262,441	237,000	112,000	21,900
Nuclear fuel	4,129	52,900	28,600	30,200
Transmission[a]	168,662	179,100	186,900	203,400
Distribution	107,993	137,200	147,700	157,300
Other	35,478	26,200	30,700	41,400
Total capital expenditures	$ 780,098	$ 814,000	$ 679,000	$ 591,000

[a] *In addition to amounts listed, we are investing in Prairie Wind Transmission. In 2013, we incurred $4.0 million of expenditures related to this investment. In 2014 we plan to incur expenditures related to Prairie Wind Transmission of $6.7 million. We do not anticipate any further investment related to Prairie Wind Transmission in 2015 and 2016.*

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. In addition, these amounts do not include any estimates for potential new environmental requirements.

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, 2013, are as follows.

Year	Long-term Debt	Long-term Debt of VIEs
	(In Thousands)	
2014	$ 250,000	$ 27,479
2015	—	27,933
2016	—	28,309
2017	125,000	26,842
2018	300,000	28,538
Thereafter	2,549,440	82,581
Total maturities	$ 3,224,440	$ 221,682

Pension Obligation

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.

We contributed $27.5 million to our pension trust in 2013 and $56.7 million in 2012. We expect to contribute approximately $30.8 million in 2014. In 2013 and 2012, we also funded $7.6 million and $13.9 million, respectively, of Wolf Creek's pension plan contributions. In 2014, we plan to contribute $5.4 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. 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, 2013.

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, 2013.

	Total	2014	2015-2016	2017-2018	Thereafter
			(In Thousands)		
Long-term debt[a]	$ 3,224,440	$ 250,000	$ —	$ 425,000	$ 2,549,440
Long-term debt of VIEs[a]	221,682	27,479	56,242	55,380	82,581
Interest on long-term debt[b]	2,698,143	173,875	317,749	308,093	1,898,426
Interest on long-term debt of VIEs	50,209	12,183	19,128	12,594	6,304
Long-term debt, including interest	6,194,474	463,537	393,119	801,067	4,536,751
Pension and post-retirement benefit expected contributions[c]	39,700	39,700	—	—	—
Capital leases[d]	99,044	6,464	11,070	9,375	72,135
Operating leases[e]	65,588	14,384	22,212	13,631	15,361
Other obligations of VIEs[f]	14,980	1,038	3,626	10,316	—
Fossil fuel[g]	1,287,180	199,289	350,411	347,846	389,634
Nuclear fuel[h]	282,569	42,196	39,303	44,806	156,264
Transmission service[i]	33,791	7,267	12,133	5,399	8,992
Unconditional purchase obligations	312,171	258,293	46,415	7,463	—
Total contractual obligations[j]	$ 8,329,497	$1,032,168	$ 878,289	$1,239,903	$ 5,179,137

[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, 2013.*

[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, fabrication and spent nuclear fuel disposal.*

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

[j] *We have $1.9 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, 2013.*

Commercial Commitments

Our commercial commitments as of December 31, 2013, consist of outstanding letters of credit that expire in 2014, some of which automatically renew annually. The letters of credit are comprised of $11.7 million related to new transmission projects, $3.3 million related to energy marketing and trading activities, $0.8 million related to workers' compensation, and $3.4 million related to other operating activities, for a total outstanding balance of $19.2 million.

OTHER INFORMATION

Changes in Prices

KCC Proceedings

We filed an application with the KCC in February 2014 to adjust our prices to include updated transmission costs as reflected in our transmission formula rate effective in January 2014 discussed below. If approved, we estimate that the new prices will increase our annual retail revenues by approximately $43.6 million. We expect the KCC to issue an order on our request in March 2014.

In December 2013, the KCC approved an order allowing us to adjust our prices to include costs incurred for property taxes. The new prices were effective in January 2014 and are expected to increase our annual retail revenues by approximately $12.7 million.

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 and to reflect cost reductions elsewhere. The new prices are expected to increase our annual retail revenues by approximately $30.7 million.

In May 2013, the KCC issued an order allowing us to adjust our prices to include costs associated with 2012 investments in environmental projects. The new prices were effective in June 2013 and are expected to increase our annual retail revenues by approximately $27.3 million.

In March 2013, we adjusted our prices to included updated transmission costs as reflected in the transmission formula rate discussed below. The KCC issued an order in July 2013 approving our adjustment which is expected to increase our annual retail revenues by approximately $11.8 million.

FERC Proceedings

In October 2013, we posted our updated transmission formula rate that includes projected 2014 transmission capital expenditures and operating costs. The updated rate was effective in January 2014 and is expected to increase our annual transmission revenues by approximately $44.3 million.

Our transmission formula rate that includes projected 2013 transmission capital expenditures and operating costs was effective in January 2013 and is expected to increase our annual transmission revenues by approximately $12.2 million. This updated rate provided the basis for our request with the KCC to adjust our retail prices to include updated transmission costs as discussed above.

Wolf Creek Outage

Wolf Creek normally operates on an 18-month planned refueling and maintenance outage schedule. However, as a result of an unscheduled maintenance outage at Wolf Creek in 2012 coupled with the longer than planned refueling and maintenance outage in 2011, we were able to defer the fall 2012 planned refueling and maintenance outage to the first quarter of 2013. The next planned refueling and maintenance outage will be in the first quarter of 2015. During the first quarter of 2014, Wolf Creek will undergo a planned maintenance outage. The outage is not part of a refueling outage and therefore will be expensed as incurred. We expect our share of the 2014 outage costs to be approximately $9.0 million.

New Financial Regulation

In 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was signed into law. Although the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also calls for new regulation of the derivatives markets, including mandatory clearing of certain swaps, exchange trading, margin requirements and other transparency requirements, which could impact our operations and consolidated financial results. We do not expect compliance with related regulations to have a significant impact on our business.

Stock-Based Compensation

We use two types of restricted share units (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 $4.4 million as of December 31, 2013, 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, 2013, 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 2013 and 2012 were as follows:

	2013	2012
	(In Thousands)	
High	$ 205	$ 309
Low	9	10
Average	83	84

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 $534.0 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2013. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $2.8 million. As of December 31, 2013, 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, 2013, investments in the NDT were allocated 50% to equity securities, 26% to debt securities, 10% to combination debt/equity securities, 9% to alternative investments, 5% to real estate securities and less than 1% to cash equivalents. As of December 31, 2013 and 2012, the fair value of the NDT investments was $175.6 million and $150.8 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 a $17.6 million decrease in the value of the NDT as of December 31, 2013.

We also maintain a trust to fund non-qualified retirement benefits. As of December 31, 2013, investments in the trust were comprised of 65% equity securities, 35% debt securities and less than 1% cash equivalents. The fair value of the investments in this trust was $34.9 million as of December 31, 2013, and $43.5 million as of December 31, 2012. 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 $3.5 million decrease in the value of the trust as of December 31, 2013.

By maintaining diversified portfolios of securities, we seek to maximize 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, 2013. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based on the assessment, we concluded that, as of December 31, 2013, 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, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* 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, 2013, based on the criteria established in *Internal Control – Integrated Framework (1992)* 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, 2013 of the Company and our report dated February 26, 2014 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 26, 2014

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, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on the criteria established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 26, 2014

WESTAR ENERGY, INC. CONSOLIDATED BALANCE SHEETS

As of December 31,	2013	2012
(Dollars in Thousands, Except Par Values)		
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4,487	$ 5,829
Accounts receivable, net of allowance for doubtful accounts of $4,596 and $4,916, respectively	250,036	224,439
Fuel inventory and supplies	239,511	249,016
Deferred tax assets	37,927	—
Prepaid expenses	15,821	15,847
Regulatory assets	135,408	114,895
Other	23,608	33,049
Total Current Assets	706,798	643,075
PROPERTY, PLANT AND EQUIPMENT, NET	7,551,916	7,013,765
PROPERTY, PLANT AND EQUIPMENT OF VARIABLE INTEREST ENTITIES, NET	296,626	321,975
OTHER ASSETS:		
Regulatory assets	620,006	887,777
Nuclear decommissioning trust	175,625	150,754
Other	246,140	247,885
Total Other Assets	1,041,771	1,286,416
TOTAL ASSETS	$ 9,597,111	$ 9,265,231
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 250,000	$ —
Current maturities of long-term debt of variable interest entities	27,479	25,942
Short-term debt	134,600	339,200
Accounts payable	233,351	180,825
Accrued dividends	43,604	41,743
Accrued taxes	69,742	58,624
Accrued interest	80,457	77,891
Regulatory liabilities	35,982	37,557
Other	80,184	84,359
Total Current Liabilities	955,399	846,141
LONG-TERM LIABILITIES:		
Long-term debt, net	2,968,958	2,819,271
Long-term debt of variable interest entities, net	194,802	222,743
Deferred income taxes	1,361,418	1,197,837
Unamortized investment tax credits	192,265	191,512
Regulatory liabilities	293,574	285,618
Accrued employee benefits	331,558	564,870
Asset retirement obligations	160,682	152,648
Other	69,924	74,336
Total Long-Term Liabilities	5,573,181	5,508,835
COMMITMENTS AND CONTINGENCIES (SEE NOTES 13 AND 15)		
EQUITY:		
Westar Energy, Inc. Shareholders' Equity:		
Common stock, par value $5 per share; authorized 275,000,000 shares; issued and outstanding 128,254,229 shares and 126,503,748 shares, respective to each date	641,271	632,519
Paid-in capital	1,696,727	1,656,972
Retained earnings	724,776	606,649
Total Westar Energy, Inc. Shareholders' Equity	3,062,774	2,896,140
Noncontrolling Interests	5,757	14,115
Total Equity	3,068,531	2,910,255
TOTAL LIABILITIES AND EQUITY	$ 9,597,111	$ 9,265,231

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31, (Dollars in Thousands, Except Per Share Amounts)	2013	2012	2011
REVENUES	**$ 2,370,654**	$ 2,261,470	$ 2,170,991
OPERATING EXPENSES:			
Fuel and purchased power	**634,797**	589,990	630,793
SPP network transmission costs	**178,604**	166,547	132,164
Operating and maintenance	**359,060**	342,055	332,989
Depreciation and amortization	**272,593**	270,464	285,322
Selling, general and administrative	**224,133**	226,012	184,695
Taxes other than income tax	**122,282**	104,269	92,599
Total Operating Expenses	**1,791,469**	1,699,337	1,658,562
INCOME FROM OPERATIONS	**579,185**	562,133	512,429
OTHER INCOME (EXPENSE):			
Investment earnings	**10,056**	7,411	9,301
Other income	**35,609**	35,378	8,652
Other expense	**(18,099)**	(19,987)	(18,398)
Total Other Income (Expense)	**27,566**	22,802	(445)
Interest expense	**182,167**	176,337	172,460
INCOME BEFORE INCOME TAXES	**424,584**	408,598	339,524
Income tax expense	**123,721**	126,136	103,344
NET INCOME	**300,863**	282,462	236,180
Less: Net income attributable to noncontrolling interests	**8,343**	7,316	5,941
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY, INC.	**292,520**	275,146	230,239
Preferred dividends	**—**	1,616	970
NET INCOME ATTRIBUTABLE TO COMMON STOCK	**$ 292,520**	$ 273,530	$ 229,269
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY (SEE NOTE 2):			
Basic earnings per common share	**$ 2.29**	$ 2.15	$ 1.95
Diluted earnings per common share	**$ 2.27**	$ 2.15	$ 1.93
AVERAGE EQUIVALENT COMMON SHARES OUTSTANDING	**127,462,994**	126,711,869	116,890,552
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.36**	$ 1.32	$ 1.28

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31,	2013	2012	2011
(Dollars in Thousands)			
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	**$ 300,863**	$ 282,462	$ 236,180
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**272,593**	270,464	285,322
Amortization of nuclear fuel	**22,690**	24,369	21,151
Amortization of deferred regulatory gain from sale leaseback	**(5,495)**	(5,495)	(5,495)
Amortization of corporate-owned life insurance	**15,149**	28,792	25,650
Non-cash compensation	**8,188**	7,255	8,422
Net deferred income taxes and credits	**123,307**	126,248	111,723
Stock-based compensation excess tax benefits	**(576)**	(1,698)	(1,180)
Allowance for equity funds used during construction	**(14,143)**	(11,706)	(5,550)
Gain on sale of non-utility investment	**—**	—	(7,246)
Gain on settlement of contractual obligations with former officers	**—**	—	(22,039)
Changes in working capital items:			
Accounts receivable	**(24,649)**	2,408	(1,638)
Fuel inventory and supplies	**10,124**	(19,227)	(21,485)
Prepaid expenses and other	**(12,316)**	(3,630)	(50,138)
Accounts payable	**7,856**	(19,161)	3,008
Accrued taxes	**14,218**	11,937	18,633
Other current liabilities	**(52,829)**	(105,169)	(107,012)
Changes in other assets	**(4,167)**	13,015	(10,167)
Changes in other liabilities	**41,990**	(1,758)	(15,443)
Cash Flows from Operating Activities	**702,803**	599,106	462,696
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	**(780,098)**	(810,209)	(697,451)
Purchase of securities — trusts	**(66,668)**	(20,473)	(49,737)
Sale of securities — trusts	**81,994**	21,604	47,534
Investment in corporate-owned life insurance	**(17,724)**	(18,404)	(19,214)
Proceeds from investment in corporate-owned life insurance	**147,658**	33,542	1,295
Proceeds from federal grant	**876**	4,775	8,561
Investment in affiliated company	**(4,947)**	(8,669)	(1,943)
Proceeds from sale of non-utility investments	**—**	—	9,246
Other investing activities	**(2,992)**	497	193
Cash Flows used in Investing Activities	**(641,901)**	(797,337)	(701,516)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	**(205,241)**	52,900	54,081
Proceeds from long-term debt	**492,347**	541,374	—
Retirements of long-term debt	**(100,000)**	(220,563)	(371)
Retirements of long-term debt of variable interest entities	**(25,942)**	(28,114)	(30,159)
Repayment of capital leases	**(2,995)**	(2,679)	(2,233)
Borrowings against cash surrender value of corporate-owned life insurance	**59,565**	67,791	67,562
Repayment of borrowings against cash surrender value of corporate-owned life insurance	**(145,418)**	(34,838)	(3,421)
Stock-based compensation excess tax benefits	**576**	1,698	1,180
Preferred stock redemption	**—**	(22,567)	—
Issuance of common stock	**32,906**	6,996	294,942
Distributions to shareholders of noncontrolling interests	**(2,419)**	(3,295)	(1,917)
Cash dividends paid	**(162,904)**	(158,182)	(138,233)
Other financing activities	**(2,719)**	—	—
Cash Flows (used in) from Financing Activities	**(62,244)**	200,521	241,431
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(1,342)**	2,290	2,611
CASH AND CASH EQUIVALENTS:			
Beginning of period	**5,829**	3,539	928
End of period	**$ 4,487**	$ 5,829	$ 3,539

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							
	Cumulative preferred stock shares	Cumulative preferred stock	Common stock shares	Common stock	Paid-in capital	Retained earnings	Non-controlling interests	Total equity
				(Dollars in Thousands)				
Balance as of December 31, 2010	214,363	$ 21,436	112,128,068	$ 560,640	$ 1,398,580	$ 423,647	$ 6,070	$ 2,410,373
Net income	—	—	—	—	—	230,239	5,941	236,180
Issuance of stock	—	—	12,951,207	64,756	230,186	—	—	294,942
Issuance of stock for compensation and reinvested dividends	—	—	619,121	3,096	4,331	—	—	7,427
Tax withholding related to stock compensation	—	—	—	—	(3,141)	—	—	(3,141)
Preferred dividends	—	—	—	—	—	(970)	—	(970)
Dividends on common stock ($1.28 per share)	—	—	—	—	—	(151,700)	—	(151,700)
Stock compensation expense	—	—	—	—	8,367	—	—	8,367
Tax benefit on stock compensation	—	—	—	—	1,180	—	—	1,180
Distributions to shareholders of noncontrolling interests	—	—	—	—	—	—	(1,917)	(1,917)
Balance as of December 31, 2011	214,363	21,436	125,698,396	628,492	1,639,503	501,216	10,094	2,800,741
Net income	—	—	—	—	—	275,146	7,316	282,462
Issuance of stock	—	—	242,463	1,212	5,784	—	—	6,996
Issuance of stock for compensation and reinvested dividends	—	—	562,889	2,815	6,274	—	—	9,089
Tax withholding related to stock compensation	—	—	—	—	(3,490)	—	—	(3,490)
Stock Redemption	(214,363)	(21,436)	—	—	—	—	—	(21,436)
Preferred dividends	—	—	—	—	—	(1,616)	—	(1,616)
Dividends on common stock ($1.32 per share)	—	—	—	—	—	(168,097)	—	(168,097)
Stock compensation expense	—	—	—	—	7,203	—	—	7,203
Tax benefit on stock compensation	—	—	—	—	1,698	—	—	1,698
Distributions to shareholders of noncontrolling interests	—	—	—	—	—	—	(3,295)	(3,295)
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 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

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

WESTAR ENERGY, INC.

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 693,000 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 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 (RECA) 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,	2013	2012
	(In Thousands)	
Fuel inventory	$ 78,368	$ 94,664
Supplies	161,143	154,352
Total	$ 239,511	$ 249,016

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,	2013	2012	2011
	(Dollars In Thousands)		
Borrowed funds	$ 11,706	$ 10,399	$ 5,589
Equity funds	14,143	11,706	5,550
Total	$ 25,849	$ 22,105	$ 11,139
Average AFUDC Rates	4.8%	5.0%	3.6%

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 2013, 2.6% in 2012 and 3.0% in 2011.

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 $46.2 million as of

December 31, 2013, and $69.2 million as of December 31, 2012. The cost of nuclear fuel charged to fuel and purchased power expense was $26.5 million in 2013, $28.3 million in 2012 and $24.6 million in 2011.

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 policies.

As of December 31,	2013	2012
	(In Thousands)	
Cash surrender value of policies	$ 1,289,457	$ 1,370,788
Borrowings against policies	(1,156,341)	(1,241,343)
Corporate-owned life insurance, net	$ 133,116	$ 129,445

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 $60.1 million as of December 31, 2013, and $62.5 million as of December 31, 2012.

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).

Under the two-class method, we reduce net income attributable to common stock by the amount of dividends declared in the current period. We allocate the remaining earnings to common stock and RSUs to the extent that each security may share in earnings as if all of the earnings for the period had been distributed. We determine the total earnings allocated to each security by adding together the amount allocated for dividends and the amount allocated for a participation feature. 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 potential issuances of common shares resulting from our forward sale agreements 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,	2013	2012	2011
	(Dollars In Thousands, Except Per Share Amounts)		
Net income	$ 300,863	$ 282,462	$ 236,180
Less: Net income attributable to noncontrolling interests	8,343	7,316	5,941
Net income attributable to Westar Energy, Inc.	292,520	275,146	230,239
Less: Preferred dividends	—	1,616	970
Net income allocated to RSUs	810	778	772
Net income allocated to common stock	$ 291,710	$ 272,752	$ 228,497
Weighted average equivalent common shares outstanding – basic	127,462,994	126,711,869	116,890,552
Effect of dilutive securities:			
RSUs	17,195	97,757	188,025
Forward sale agreements	818,505	89,160	1,211,645
Weighted average equivalent common shares outstanding – diluted [a]	128,298,694	126,898,786	118,290,222
Earnings per common share, basic	$ 2.29	$ 2.15	$ 1.95
Earnings per common share, diluted	$ 2.27	$ 2.15	$ 1.93

[a] *For the years ended December 31, 2013, 2012 and 2011, we had no antidilutive shares.*

Supplemental Cash Flow Information

Year Ended December 31,	2013	2012	2011
		(In Thousands)	
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$ 148,691	$ 143,564	$ 145,570
Interest on financing activities of VIEs	13,892	16,214	18,167
Income taxes, net of refunds	(11)	(4,378)	(17,519)
NON-CASH INVESTING TRANSACTIONS:			
Property, plant and equipment additions	127,544	89,354	105,435
Property, plant and equipment of VIEs	(14,282)	—	—
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and compensation plans	9,641	9,089	7,427
Deconsolidation of VIEs	(14,282)	—	—
Assets acquired through capital leases	334	10,683	43,011

Investment Earnings — Sale of Non-utility Investment

In 2011, we recorded a $7.2 million gain on the sale of a non-utility investment.

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,	2013	2012
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$ 277,122	$ 542,174
Amounts due from customers for future income taxes, net	163,742	169,091
Depreciation	71,047	73,672
Debt reacquisition costs	63,882	67,721
Ad valorem tax	34,492	21,812
Wolf Creek outage	29,026	14,143
Treasury yield hedges	27,594	28,573
Asset retirement obligations	23,555	22,633
Retail energy cost adjustment	22,138	4,262
Disallowed plant costs	15,964	16,106
Energy efficiency program costs	14,477	18,835
Storm costs	1,483	11,076
Other regulatory assets	10,892	12,574
Total regulatory assets	$ 755,414	$ 1,002,672
Regulatory Liabilities:		
Removal costs	$ 114,148	$ 128,971
Deferred regulatory gain from sale leaseback	86,551	92,046
Nuclear decommissioning	43,272	25,937
La Cygne dismantling costs	20,505	18,093
Other post-retirement benefits costs	19,000	10,722
Retail energy cost adjustment	15,414	16,595
Kansas tax credits	11,076	10,781
Jurisdictional allowance for funds used during construction	7,893	4,457
Gain on sale of oil	4,278	6,219
Fuel supply and electricity contracts	2,635	4,387
Other regulatory liabilities	4,784	4,967
Total regulatory liabilities	$ 329,556	$ 323,175

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 $223.5 million for pension and post-retirement benefit obligations and $53.7 million for actual pension expense in excess of the amount of such expense recognized in setting our prices. The decrease from 2012 to 2013 is primarily attributable to the favorable increase in the funded status of our and Wolf Creek's pension and post-retirement plans. During 2014, we will amortize to expense approximately $24.9 million of the benefit obligations and approximately $9.8 million of the excess pension expense. As authorized in the April 2012 Kansas Corporation Commission (KCC) order discussed below, we are amortizing the excess pension expense as of the time of our filing with the KCC 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 on which we do not earn a return. 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 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.
- **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.
- **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.
- **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.
- **Treasury yield hedges:** Represents the effective portion of losses on treasury yield hedge transactions. This amount will be amortized to interest expense over the term of the related debt. See Note 4, "Financial Instruments and Trading Securities — Cash Flow Hedges," for additional information regarding our treasury yield hedge transactions. 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.

- **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. This item represents the actual cost of fuel consumed in producing electricity and the cost of purchased power in excess of the amounts we have collected from customers. We expect to recover in our prices this shortfall over a one-year period. We have two retail jurisdictions, each with a separate cost of fuel. For the reporting period, this resulted in us simultaneously reporting both a regulatory asset and a regulatory liability for this item. 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 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.
- **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.
- **Storm costs:** We accumulated and deferred for future recovery costs related to restoring our electric transmission and distribution systems from damages sustained during unusually damaging storms. We will amortize the remaining costs over a two-year period and no longer 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.

- **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.
- **Deferred regulatory gain from sale leaseback:** Represents the gain KGE recorded on the 1987 sale and leaseback of its 50% interest in La Cygne Generation Station (La Cygne) unit 2. We amortize the gain over the lease term.
- **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 our ARO. See Note 4, "Financial Instruments and Trading Securities," Note 5, "Financial Investments" and Note 14, "Asset Retirement Obligations," for information regarding our nuclear decommissioning trust (NDT) and our ARO.
- **La Cygne 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.
- **Other post-retirement benefits costs:** Includes $6.7 million for post-retirement obligations and $12.3 million of other post-retirement benefits expense recognized in setting our prices in excess of actual other post-retirement benefits expense. We amortize the amount over a five-year period.
- **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. We have two retail jurisdictions, each with a separate cost of fuel. For the reporting period, this resulted in us simultaneously reporting both a regulatory asset and a regulatory liability for this item.
- **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.
- **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 charges are placed in service. The AFUDC is amortized to depreciation expense over the useful life of the asset that is placed in service.
- **Gain on sale of oil:** We discontinued the use of a certain type of oil in our plants. As a result, we sold this oil inventory for a gain. This item represents the remaining portion of the gain that will be refunded to customers over a three-year period.
- **Fuel supply and electricity contracts:** We use fair value accounting for some of our fuel supply and electricity contracts. This represents the non-cash net gain position on fuel supply and electricity contracts that are recorded at fair value. Under the RECA, fuel supply contract market gains accrue to the benefit of our customers.
- **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 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 are expected to increase our annual retail revenues by approximately $30.7 million.

In April 2012, the KCC issued an order expected to increase our annual retail revenues by approximately $50.0 million. In addition, we revised our depreciation rates to reflect changes in the estimated useful lives of some of our depreciable assets. The change in estimate will decrease annual depreciation expense by $43.6 million. The new prices were effective shortly after having received the order.

Environmental Costs

In August 2011, the KCC issued an order ruling that Kansas City Power & Light Company's (KCPL) decision to make environmental upgrades at La Cygne to comply with environmental regulations is prudent and the $1.2 billion project cost estimate is reasonable. We have a 50% interest in La Cygne and intervened in the proceeding. The KCC denied our request to collect our approximately $610.0 million share of the capital investment for the environmental upgrades through our environmental cost recovery rider (ECRR). However, as noted above, we received an order regarding an abbreviated rate review to update our prices to include a portion of the capital costs associated with the project.

We also 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. In the most recent three years, the KCC issued orders related to such filings allowing us to increase our annual retail revenues by approximately:

- $27.3 million effective in June 2013;
- $19.5 million effective in June 2012; and
- $10.4 million effective in June 2011.

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 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:

- $11.8 million effective in March 2013;
- $36.7 million effective in April 2012; and
- $17.4 million effective in April 2011.

Energy Efficiency

We make annual filings with the KCC to adjust our prices to include previously deferred amounts associated with various energy efficiency programs. In the most recent three years, the KCC issued orders related to such filings allowing us to adjust our annual retail revenues by approximately:

- $1.3 million decrease effective in November 2013;
- $1.1 million increase effective in October 2012; and
- $4.9 million increase effective in November 2011.

Property Tax Surcharge

We make annual filings with the KCC to adjust our prices to include the cost incurred for property taxes. In the most recent three years, the KCC issued orders related to such filings allowing us to increase our annual retail revenues by approximately:

- $15.2 million effective in January 2013;
- $5.9 million effective in January 2012; and
- $0.7 million effective in January 2011.

FERC Proceedings

In October of each year, we post an updated transmission formula rate 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 three years, we posted our transmission formula rate which was expected to increase our annual transmission revenues by approximately:

- $12.2 million effective in January 2013;
- $38.2 million effective in January 2012; and
- $15.9 million effective in January 2011.

4. FINANCIAL INSTRUMENTS AND TRADING SECURITIES

Values of Financial and Derivative 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, 2013		As of December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In Thousands)			
Fixed-rate debt	$ 3,102,500	$ 3,294,209	$ 2,702,500	$ 3,178,752
Fixed-rate debt of VIEs	221,682	241,241	247,624	275,341

Recurring Fair Value Measurements

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

As of December 31, 2013	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Nuclear Decommissioning Trust:				
Domestic equity	$ —	$ 49,957	$ 5,817	$ 55,774
International equity	—	31,816	—	31,816
Core bonds	—	18,107	—	18,107
High-yield bonds	—	12,902	—	12,902
Emerging market bonds	—	11,055	—	11,055
Other fixed income	—	4,690	—	4,690
Combination debt/equity/ other fund	—	17,093	—	17,093
Alternative investments	—	—	15,675	15,675
Real estate securities	—	—	8,511	8,511
Cash equivalents	2	—	—	2
Total Nuclear Decommissioning Trust	2	145,620	30,003	175,625
Trading Securities:[a]				
Domestic equity	—	18,075	—	18,075
International equity	—	4,519	—	4,519
Core bonds	—	12,166	—	12,166
Cash equivalents	166	—	—	166
Total Trading Securities	166	34,760	—	34,926
Total Assets Measured at Fair Value	$ 168	$ 180,380	$ 30,003	$ 210,551
As of December 31, 2012				
Assets:				
Nuclear Decommissioning Trust:				
Domestic equity	$ —	$ 56,157	$ 4,899	$ 61,056
International equity	—	30,041	—	30,041
Core bonds	—	28,350	—	28,350
High-yield bonds	—	8,782	—	8,782
Emerging market bonds	—	6,428	—	6,428
Combination debt/equity fund	—	8,194	—	8,194
Real estate securities	—	—	7,865	7,865
Cash equivalents	38	—	—	38
Total Nuclear Decommissioning Trust	38	137,952	12,764	150,754
Trading Securities:				
Domestic equity	—	22,470	—	22,470
International equity	—	5,744	—	5,744
Core bonds	—	15,104	—	15,104
Cash equivalents	166	—	—	166
Total Trading Securities	166	43,318	—	43,484
Total Assets Measured at Fair Value	$ 204	$ 181,270	$ 12,764	$ 194,238

[a] *The decrease in the fair value of trading securities was due to withdrawing $15.3 million.*

The following table provides reconciliations of assets and liabilities held in the NDT measured at fair value using significant level 3 inputs for the years ended December 31, 2013 and 2012.

	Domestic Equity	Alternative Investments	Real Estate Securities	Net Balance
		(In Thousands)		
Balance as of December 31, 2012	$ 4,899	$ —	$ 7,865	$ 12,764
Total realized and unrealized gains included in:				
Regulatory liabilities	940	675	646	2,261
Purchases	341	15,000	287	15,628
Sales	(363)	—	(287)	(650)
Balance as of December 31, 2013	$ 5,817	$ 15,675	$ 8,511	$ 30,003
Balance as of December 31, 2011	$ 3,931	$ —	$ 7,095	$ 11,026
Total realized and unrealized gains included in:				
Regulatory liabilities	90	—	770	860
Purchases	891	—	320	1,211
Sales	(13)	—	(320)	(333)
Balance as of December 31, 2012	$ 4,899	$ —	$ 7,865	$ 12,764

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 we recorded to regulatory liabilities on our consolidated financial statements during the years ended December 31, 2013 and 2012, attributed to level 3 assets and liabilities.

	Domestic Equity	Alternative Investments	Real Estate Securities	Net Balance
		(In Thousands)		
Year ended December 31, 2013	$ 577	$ 675	$ 359	$ 1,611
Year ended December 31, 2012	77	—	451	528

Some of our investments in the NDT and our trading securities portfolio are measured at net asset value, do not have readily determinable fair values and 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, 2013		As of December 31, 2012		As of December 31, 2013	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
	(In Thousands)					
Nuclear Decommissioning Trust:						
Domestic equity	$ 5,817	$ 2,683	$ 4,899	$ 1,024	[a]	[a]
Alternative investments	15,675	—	—	—	[b]	[b]
Real estate securities	8,511	—	7,865	—	Quarterly	80 days
Total Nuclear Decommissioning Trust	$ 30,003	$ 2,683	$ 12,764	$ 1,024		
Trading Securities:						
Domestic equity	$ 18,075	$ —	$ 22,470	$ —	Upon Notice	1 day
International equity	4,519	—	5,744	—	Upon Notice	1 day
Core bonds	12,166	—	15,104	—	Upon Notice	1 day
Total Trading Securities	34,760	—	43,318	—		
Total	$ 64,763	$ 2,683	$ 56,082	$ 1,024		

[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. One fund has begun to make distributions and we expect the other to begin in 2014. Our initial investment in the third fund occurred in the 3rd quarter of 2013. This fund's term will be 15 years, subject to the General Partner's right to extend the term for up to three additional one-year periods.*

[b] *This fund has an initial lock-up period of 24 months. Redemptions are allowed, on a quarterly basis, after 24 months at the sole discretion of the fund's board of directors. A 65-day notice of redemption is required. There is a holdback on final redemptions.*

Nonrecurring Fair Value Measurements

We have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operations of such assets. In 2013, we recorded no additional AROs. In 2012, we recorded $3.1 million of additional AROs. We initially record AROs at fair value for the estimated cost to satisfy the retirement obligation.

We measure the fair value of AROs by estimating the cost to satisfy the retirement obligation then discounting that value at a risk- and inflation-adjusted rate. To determine the cost to satisfy the retirement obligation, experts reporting to the Chief Operating Officer must estimate the cost of basic inputs such as labor, energy, materials, timing and disposal and make assumptions on the method of disposal or decommissioning. Our estimates are validated with contractor estimates and when we satisfy other similar obligations. We estimate the cost to satisfy the 2012 ARO layer is approximately $3.1 million.

To determine the appropriate discount rate, we use observable inputs such as inflation rates, short and long-term yields for U.S. government securities and our nonperformance risk. Due to the significant unobservable inputs required in our measurement, we have determined that our fair value measurements of our AROs are level 3 in the fair value hierarchy. For additional information on our AROs, see Note 14, "Asset Retirement Obligations."

Derivative Instruments

Cash Flow Hedges

In 2011, we entered into treasury yield hedge transactions to hedge our interest rate risk associated with a $125.0 million portion of a forecasted issuance of fixed rate debt. These transactions were designated and qualified as cash flow hedges and measured at fair value by estimating the net present value of a series of payments using market-based models with observable inputs such as the spread between the 30-year U.S Treasury bill yield and the contracted, fixed yield. As a result of regulatory accounting treatment, we report the effective portion of the gains or losses on these derivative instruments as a regulatory liability or regulatory asset and amortize such amounts to interest expense over the term of the related debt. During the first quarter of 2012, we settled the treasury yield hedge transactions for a cost of $29.7 million, which will be amortized to interest expense over the 30-year term of the debt issued in March 2012. See Note 9, "Long-Term Debt" for additional information regarding the debt issuance. As of December 31, 2013 and 2012, we had recorded $27.6 million and $28.6 million, respectively, as a regulatory asset.

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 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.

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 of $27.0 million and $30.0 million as of December 31, 2013 and 2012, respectively. For additional information on our benefit obligations, see Note 11, "Employee Benefit Plans."

As of December 31, 2013 and 2012, we measured the fair value of trust assets at $34.9 million and $43.5 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, 2013, 2012 and 2011, we recorded unrealized gains of $6.7 million, $4.1 million and $0.3 million, respectively.

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, 2013, and December 31, 2012. As of December 31, 2013, the fair value of available-for-sale bond funds was $46.8 million. The NDT did not have investments in debt securities outside of investment funds as of December 31, 2013.

Using the specific identification method to determine cost, we realized gains on our available-for-sale securities of $5.3 million in 2013, $0.6 million in 2012 and $1.3 million in 2011. 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 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, 2013 and 2012.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Allocation
		(Dollars in Thousands)			
As of December 31, 2013					
Domestic equity	$ 40,976	$ 14,799	$ (1)	$ 55,774	32%
International equity	26,581	5,266	(31)	31,816	18%
Core bonds	18,287	—	(180)	18,107	10%
High-yield bonds	12,275	627	—	12,902	7%
Emerging market bonds	12,207	—	(1,152)	11,055	6%
Other fixed income	4,684	6	—	4,690	3%
Combination debt/equity/ other fund	14,964	2,380	(251)	17,093	10%
Alternative investments	15,000	675	—	15,675	9%
Real estate securities	10,268	—	(1,757)	8,511	5%
Cash equivalents	2	—	—	2	<1%
Total	$ 155,244	$ 23,753	$ (3,372)	$ 175,625	100%
As of December 31, 2012					
Domestic equity	$ 53,598	$ 7,458	$ —	$ 61,056	41%
International equity	28,248	1,793	—	30,041	20%
Core bonds	27,309	1,041	—	28,350	19%
High-yield bonds	8,022	760	—	8,782	6%
Emerging market bonds	6,080	348	—	6,428	4%
Combination debt/ equity fund	8,074	120	—	8,194	5%
Real estate securities	9,981	—	(2,116)	7,865	5%
Cash equivalents	38	—	—	38	<1%
Total	$ 141,350	$ 11,520	$ (2,116)	$ 150,754	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, 2013 and 2012.

	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, 2013						
Domestic equity	$ 59	$ (1)	$ —	$ —	$ 59	$ (1)
International equity	6,244	(31)	—	—	6,244	(31)
Core bonds	18,107	(180)	—	—	18,107	(180)
Emerging market bonds	11,055	(1,152)	—	—	11,055	(1,152)
Combination debt/ equity/other funds	6,283	(251)	—	—	6,283	(251)
Real estate securities	—	—	8,511	(1,757)	8,511	(1,757)
Total	$ 41,748	$ (1,615)	$ 8,511	$ (1,757)	$ 50,259	$ (3,372)
As of December 31, 2012						
Real estate securities	$ —	$ —	$ 7,865	$ (2,116)	$ 7,865	$ (2,116)

6. PROPERTY, PLANT AND EQUIPMENT

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

As of December 31,	2013	2012
	(In Thousands)	
Electric plant in service	$ 9,753,787	$ 9,389,192
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,971,735)	(3,791,545)
	6,584,370	6,399,965
Construction work in progress	904,586	532,332
Nuclear fuel, net	62,960	81,468
Net property, plant and equipment	$ 7,551,916	$ 7,013,765

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

As of December 31,	2013	2012
	(In Thousands)	
Electric plant of VIEs	$ 513,793	$ 543,548
Accumulated depreciation of VIEs	(217,167)	(221,573)
Net property, plant and equipment of VIEs	$ 296,626	$ 321,975

We revised our depreciation rates to reflect changes in the estimated useful lives of some of our assets in 2012. We recorded depreciation expense on property, plant and equipment of $249.9 million in 2013, $247.8 million in 2012 and $262.6 million in 2011. Approximately $9.7 million, $9.8 million and $9.8 million of depreciation expense in 2013, 2012 and 2011, 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, 2013, 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	$ 334,054	$ 151,674	$ 280,688	368	50
JEC unit 1[a]	July 1978	530,407	194,944	166,073	661	92
JEC unit 2[a]	May 1980	504,508	190,660	13,138	658	92
JEC unit 3[a]	May 1983	713,937	296,278	1,906	664	92
Wolf Creek[b]	Sept. 1985	1,596,382	773,724	144,083	547	47
State Line[c]	June 2001	110,408	48,357	305	201	40
Total		$ 3,789,696	$ 1,655,637	$ 606,193	3,099	

[a] *Jointly owned with KCPL. Our 8% leasehold interest in 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 341 MW of net capacity. The VIE's investment in the 50% interest was $392.1 million and accumulated depreciation was $187.4 million as of December 31, 2013. We include these amounts in property, plant and equipment of variable interest entities, net on our consolidated balance sheets. See Note 17, "Variable Interest Entities," for additional information about VIEs.

8. SHORT-TERM DEBT

In July 2013 Westar Energy extended the term of its $730.0 million revolving credit facility to terminate 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, 2013, no amounts had been borrowed and $18.4 million of letters of credit had been issued under this revolving credit facility. As of December 31, 2012, none had been borrowed and $13.8 million of letters of credit had been issued under this revolving credit facility.

In 2011, Westar Energy entered into a revolving credit facility with a syndicate of banks for $270.0 million. In February 2014, Westar Energy extended the term of the $270.0 million revolving credit facility to February 2017, provided that $20.0 million of this facility will terminate in February 2016. As 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, 2013 and 2012, Westar Energy had no borrowed amounts or letters of credit outstanding under this revolving credit facility.

In 2011, Westar Energy entered into 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 repay borrowings under Westar Energy's revolving credit facilities, for working capital and/or for other general corporate purposes. Westar Energy had issued $134.6 million and $339.2 million of commercial paper as of December 31, 2013 and 2012, 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, 2013 and December 31, 2012, was 0.28% and 0.46%, respectively. Additional information regarding our short-term debt is as follows.

As of December 31,	2013	2012
	(Dollars In Thousands)	
Weighted average short-term debt outstanding during the year	$ 228,352	$ 298,907
Weighted daily average interest rates during the year, excluding fees	0.39%	0.55%

Our interest expense on short-term debt was $2.4 million in 2013, $3.2 million in 2012 and $3.9 million in 2011.

9. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

As of December 31,	2013	2012
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
6.00% due 2014	$ 250,000	$ 250,000
5.15% due 2017	125,000	125,000
8.625% due 2018	300,000	300,000
5.10% due 2020	250,000	250,000
5.95% due 2035	125,000	125,000
5.875% due 2036	150,000	150,000
4.125% due 2042	550,000	550,000
4.10% due 2043	250,000	—
4.625% due 2043	250,000	—
	2,250,000	1,750,000
Pollution control bond series:		
Variable due 2032, 0.12% as of December 31, 2013; 0.32% as of December 31, 2012	45,000	45,000
Variable due 2032, 0.12% as of December 31, 2013; 0.26% as of December 31, 2012	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
	625,000	625,000
Pollution control bond series:		
Variable due 2027, 0.10% as of December 31, 2013; 0.26% as of December 31, 2012	21,940	21,940
5.30% due 2031	108,600	108,600
5.30% due 2031	18,900	18,900
4.85% due 2031	50,000	50,000
5.60% due 2031	—	50,000
6.00% due 2031	—	50,000
5.00% due 2031	50,000	50,000
Variable due 2032, 0.10% as of December 31, 2013; 0.26% as of December 31, 2012	14,500	14,500
Variable due 2032, 0.10% as of December 31, 2013; 0.26% as of December 31, 2012	10,000	10,000
	273,940	373,940
Total long-term debt	3,224,440	2,824,440
Unamortized debt discount[a]	(5,482)	(5,169)
Long-term debt due within one year	(250,000)	—
Long-term debt, net	$ 2,968,958	$ 2,819,271
Variable Interest Entities		
6.99% due 2014[b]	316	866
5.92 % due 2019[b]	13,243	17,630
5.647% due 2021[b]	208,123	229,128
Total long-term debt of variable interest entities	221,682	247,624
Unamortized debt premium[a]	599	1,061
Long-term debt of variable interest entities due within one year	(27,479)	(25,942)
Long-term debt of variable interest entities, net	$ 194,802	$ 222,743

[a] *We amortize debt discounts and premiums 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.*

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, 2013, approximately $505.3 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, 2013, approximately $1.1 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, 2013, we had $121.9 million of variable rate, tax-exempt bonds. 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 August 2013, Westar Energy issued $250.0 million principal amount of first mortgage bonds bearing stated interest at 4.625% and maturing September 2043.

In June 2013, KGE redeemed two pollution control bond series with an aggregate principal amount of $100.0 million and stated interest rates at 5.60% and 6.00%.

In March 2013, Westar Energy issued $250.0 million principal amount of first mortgage bonds bearing stated interest at 4.10% and maturing April 2043.

In May 2012, Westar Energy issued $300.0 million principal amount of first mortgage bonds at a discount yielding 4.157%, bearing stated interest at 4.125% and maturing in March 2042. These bonds constitute a further issuance of a series of bonds initially issued in March 2012 in the principal amount of $250.0 million, at a discount yielding 4.13%, bearing stated interest at 4.125% and maturing in March 2042.

In May 2012, Westar Energy redeemed $150.0 million aggregate principal amount of 6.10% first mortgage bonds. Additionally, in March 2012 Westar Energy redeemed $57.2 million aggregate principal amount of 5.00% pollution control bonds and KGE redeemed $13.3 million aggregate principal amount of 5.10% pollution control bonds.

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, 2013, are as follows.

Year	Long-term Debt	Long-term Debt of VIEs
	(In Thousands)	
2014	$ 250,000	$ 27,479
2015	—	27,933
2016	—	28,309
2017	125,000	26,842
2018	300,000	28,538
Thereafter	2,549,440	82,581
Total maturities	$ 3,224,440	$ 221,682

Interest expense on long-term debt was $154.9 million in 2013, $145.6 million in 2012 and $142.6 million in 2011. Interest expense on long-term debt of VIEs was $13.0 million in 2013, $15.1 million in 2012 and $16.8 million in 2011.

10. TAXES

Income tax expense is comprised of the following components.

Year Ended December 31,	2013	2012	2011
		(In Thousands)	
Income Tax Expense (Benefit):			
Current income taxes:			
Federal	$ 135	$ (691)	$ (8,575)
State	279	579	196
Deferred income taxes:			
Federal	102,030	102,960	93,089
State	24,443	26,300	21,337
Investment tax credit amortization	(3,166)	(3,012)	(2,703)
Income tax expense	$ 123,721	$ 126,136	$ 103,344

Deferred tax assets and liabilities are reflected on our consolidated balance sheets as follows.

As of December 31,	2013	2012
	(In Thousands)	
Current deferred tax assets	$ 37,927	$ —
Other current liabilities	—	8,654
Non-current deferred tax liabilities	1,361,418	1,197,837
Net deferred tax liabilities	$ 1,323,491	$ 1,206,491

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,	2013	2012
	(In Thousands)	
Deferred tax assets:		
Tax credit carryforward[a]	$ 212,635	$ 199,160
Net operating loss carryforward[b]	110,588	111,869
Deferred employee benefit costs	85,720	191,997
Deferred state income taxes	57,243	55,577
Deferred regulatory gain on sale-leaseback	38,124	40,543
Alternative minimum tax carryforward[c]	35,666	36,471
Deferred compensation	30,022	28,319
Accrued liabilities	17,396	15,969
Disallowed costs	11,453	12,083
LaCygne dismantling cost	8,110	7,156
Capital loss carryforward[d]	3,447	11,509
Other	20,058	13,741
Total gross deferred tax assets	630,462	724,394
Less: Valuation allowance[e]	3,504	13,812
Deferred tax assets	$ 626,958	$ 710,582
Deferred tax liabilities:		
Accelerated depreciation	$ 1,390,669	$ 1,255,892
Acquisition premium	171,907	179,920
Amounts due from customers for future income taxes, net	163,742	169,091
Deferred employee benefit costs	85,720	191,997
Deferred state income taxes	51,504	50,134
Pension expense tracker	21,230	22,437
Storm costs	21,165	4,373
Debt reacquisition costs	19,985	22,313
Other	24,527	20,916
Total deferred tax liabilities	$ 1,950,449	$ 1,917,073
Net deferred tax liabilities	$ 1,323,491	$ 1,206,491

[a] *Based on filed tax returns and amounts expected to be reported in current year tax returns (December 31, 2013), we had available federal general business tax credits of $50.2 million and state investment tax credits of $162.4 million. The federal general business tax credits were primarily generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These tax credits expire beginning in 2020 and ending in 2033. The state investment tax credits expire beginning in 2017 and ending in 2029.*

[b] *As of December 31, 2013, we had a federal net operating loss carryforward of $277.6 million, which is available to offset federal taxable income. The net operating losses will expire beginning in 2031 and ending in 2032.*

[c] *As of December 31, 2013, we had available an alternative minimum tax credit carryforward of $35.7 million, which has an unlimited carryforward period.*

[d] *As of December 31, 2013, we had an unused capital loss carryforward of $8.7 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 $3.5 million. The total valuation allowance related to the deferred tax assets was $3.5 million as of December 31, 2013, and $13.8 million as of December 31, 2012.*

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,	2013	2012	2011
Statutory federal income tax rate	35.0%	35.0%	35.0%
Effect of:			
Corporate-owned life insurance policies	(5.4)	(4.9)	(4.5)
State income taxes	3.8	4.3	4.1
Production tax credits	(2.3)	(2.4)	(2.9)
Flow through depreciation for plant-related differences	2.2	1.4	1.8
AFUDC equity	(1.2)	(1.0)	(0.6)
Capital loss utilization carryforward	(1.1)	(0.3)	(0.5)
Amortization of federal investment tax credits	(0.7)	(0.7)	(0.8)
Liability for unrecognized income tax benefits	0.1	0.2	—
Other	(1.3)	(0.7)	(1.2)
Effective income tax rate	29.1%	30.9%	30.4%

We file income tax returns in the U.S. federal jurisdiction as well as various state and foreign jurisdictions. The income tax returns we file will likely be audited by the Internal Revenue Service (IRS) or other tax authorities. With few exceptions, the statute of limitations with respect to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities remains open for tax year 2008 and forward.

The IRS has examined our federal income tax return filed for tax year 2010 and the amended federal income tax returns we filed for tax years 2007, 2008 and 2009. The examination results, which were approved by the Joint Committee on Taxation of the U.S. Congress and accepted by the IRS in April 2013, did not have a significant impact on our consolidated statements of income or cash flows.

On September 13, 2013, the IRS and United States Treasury Department released final regulations regarding the deduction and capitalization of expenditures related to tangible property, including the tax treatment of, among other things, materials and supplies and the determination of whether expenditures with respect to tangible property are a deductible repair or must be capitalized, and re-proposed regulations regarding dispositions of property under the Modified Accelerated Cost Recovery System. The regulations are generally effective for tax years beginning on or after January 1, 2014, but may be adopted in earlier years under certain circumstances. On January 24, 2014, the IRS issued transition guidance that provides the procedures for taxpayers to change their method of accounting to comply with the regulations. We intend to adopt the guidance effective January 1, 2014. We do not expect the adoption of the regulations to have a material impact on our consolidated financial statements.

The liability for unrecognized income tax benefits increased from $1.2 million at December 31, 2012, to $1.7 million at December 31, 2013. The net increase in the liability for unrecognized income tax benefits was largely attributable to tax positions taken with respect to the capitalization of plant related expenditures. We do not expect significant changes in the liability for 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:

	2013	2012	2011
		(In Thousands)	
Liability for unrecognized income tax benefits as of January 1	$ 1,219	$ 2,483	$ 1,888
Additions based on tax positions related to the current year	224	373	967
Additions for tax positions of prior years	325	—	939
Reductions for tax positions of prior years	(65)	(1,637)	(563)
Settlements	—	—	(748)
Liability for unrecognized income tax benefits as of December 31	$ 1,703	$ 1,219	$ 2,483

The liability for unrecognized income tax benefits, as disclosed above, is net of reductions to deferred tax assets for credit carryforwards of $0.3 million and $0.2 million as of December 31, 2012 and 2011, respectively. There were no reductions to deferred tax assets for credit carryforwards as of December 31, 2013. The amounts of unrecognized income tax benefits that, if recognized, would favorably impact our effective income tax rate, were $2.4 million, $2.0 million and $1.2 million (net of tax) as of December 31, 2013, 2012 and 2011, respectively.

Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. During 2013 and 2012, we did not reverse any interest expense previously recorded for income tax uncertainties. During 2011, we reversed interest expense previously recorded for income tax uncertainties of $0.2 million. As of December 31, 2013 and 2012, we had $0.2 million accrued for interest on our liability related to unrecognized income tax benefits. We accrued no penalties at either December 31, 2013 or 2012.

As of December 31, 2013 and 2012, we had recorded $1.5 million for probable assessments of taxes other than income taxes.

In July 2013, the FASB issued new accounting guidance on presenting an unrecognized tax benefit when a net operating loss carryforward exists. An unrecognized tax benefit should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, similar tax loss, or a tax credit carryforward. To the extent a net operating loss carryforward is not available to settle any additional income taxes that would result from the disallowance of a tax position at the reporting date; the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. The guidance is effective for fiscal years beginning after December 15, 2013. This guidance is not expected to have a material impact on our consolidated financial results.

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. We expect to fund our post-retirement plan each year at least to a level equal to current year post-retirement expense.

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,	2013	2012	2013	2012
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 928,708	$ 876,308	$ 152,564	$ 150,078
Service cost	21,420	19,556	2,028	2,057
Interest cost	38,520	39,576	6,007	6,298
Plan participants' contributions	—	—	2,961	2,987
Benefits paid[a]	(36,529)	(60,229)	(10,968)	(9,799)
Actuarial (gains) losses	(128,339)	53,497	(19,531)	943
Benefit obligation, end of year[b]	$ 823,780	$ 928,708	$ 133,061	$ 152,564
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 547,931	$ 481,077	$ 106,793	$ 91,858
Actual return on plan assets	68,151	67,328	17,361	10,673
Employer contributions	27,500	56,700	5,318	10,803
Plan participants' contributions	—	—	2,830	2,845
Benefits paid[a]	(33,765)	(57,174)	(10,536)	(9,386)
Fair value of plan assets, end of year	$ 609,817	$ 547,931	$ 121,766	$ 106,793
Funded status, end of year	$ (213,963)	$ (380,777)	$ (11,295)	$ (45,771)

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2013	2012	2013	2012
	(In Thousands)			
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (2,740)	$ (2,870)	$ (242)	$ (298)
Noncurrent liability	(211,223)	(377,907)	(11,053)	(45,473)
Net amount recognized	$ (213,963)	$ (380,777)	$ (11,295)	$ (45,771)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 186,365	$ 383,365	$ (18,890)	$12,436
Prior service cost	3,393	3,994	13,942	16,467
Transition obligation	—	—	—	325
Net amount recognized	$ 189,758	$ 387,359	$ (4,948)	$ 29,228

[a] *In 2012 certain former employees received a one-time lump sum payment of their pension benefits totaling $26.1 million.*

[b] *As of December 31, 2013 and 2012, pension benefits include non-qualified benefit obligations of $27.0 million and $30.0 million, respectively, which are funded by a trust containing assets of $34.9 million and $43.5 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.*

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2013	2012	2013	2012
	(Dollars In Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 823,780	$ 928,708	$ —	$ —
Fair value of plan assets	609,817	547,931	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 732,150	$ 806,888	—	—
Fair value of plan assets	609,817	547,931	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	—	—	$ 133,061	$ 152,564
Fair value of plan assets	—	—	121,766	106,793
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.07%	4.13%	4.88%	3.99%
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.

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.

	Pension Benefits		
Year Ended December 31,	2013	2012	2011
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 21,420	$ 19,556	$ 16,076
Interest cost	38,520	39,576	40,045
Expected return on plan assets	(33,405)	(32,283)	(31,087)
Amortization of unrecognized:			
Transition obligation, net	—	—	—
Prior service costs	601	612	1,213
Actuarial loss, net	33,914	32,778	23,659
Net periodic cost before regulatory adjustment	61,050	60,239	49,906
Regulatory adjustment[a]	3,693	(6,523)	(22,098)
Net periodic cost	$ 64,743	$ 53,716	$ 27,808
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain)/loss	$ (163,086)	$ 18,451	$ 97,429
Amortization of actuarial (loss)	(33,914)	(32,778)	(23,659)
Current year prior service cost	—	—	—
Amortization of prior service costs	(601)	(612)	(1,213)
Amortization of transition obligation	—	—	—
Total recognized in regulatory assets	$ (197,601)	$ (14,939)	$ 72,557
Total recognized in net periodic cost and regulatory assets	$ (132,858)	$ 38,777	$ 100,365
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	4.13%	4.50%	5.35%
Expected long-term return on plan assets	6.50%	6.50%	6.50%
Compensation rate increase	4.00%	4.00%	4.00%

	Post-retirement Benefits		
Year Ended December 31,	2013	2012	2011
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 2,028	$ 2,057	$ 1,803
Interest cost	6,007	6,298	6,793
Expected return on plan assets	(6,691)	(5,491)	(5,002)
Amortization of unrecognized:			
Transition obligation, net	325	3,912	3,911
Prior service costs	2,524	2,524	2,524
Actuarial loss, net	1,125	1,503	702
Net periodic cost before regulatory adjustment	5,318	10,803	10,731
Regulatory adjustment[a]	2,922	23	1,344
Net periodic cost	$ 8,240	$ 10,826	$ 12,075
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain)/loss	$ (30,201)	$ (4,239)	$ 10,421
Amortization of actuarial (loss)	(1,125)	(1,503)	(702)
Current year prior service cost	—	—	4,451
Amortization of prior service costs	(2,525)	(2,524)	(2,524)
Amortization of transition obligation	(325)	(3,912)	(3,911)
Total recognized in regulatory assets	$ (34,176)	$ (12,178)	$ 7,735
Total recognized in net periodic cost and regulatory assets	$ (25,936)	$ (1,352)	$ 19,810
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	3.99%	4.25%	5.00%
Expected long-term return on plan assets	6.00%	6.00%	6.00%
Compensation rate increase	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 into net periodic cost in 2014.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss (gain)	$ 19,362	$ (742)
Prior service cost	525	2,524
Total	$ 19,887	$ 1,782

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.

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

As of December 31,	2013	2012
Health care cost trend rate assumed for next year	7.5%	8.0%
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	2019	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	$ 153	$ (136)
Effect on post-retirement benefit obligation	2,098	(1,901)

Plan Assets

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 carefully 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 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 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.

As noted above, 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 about 39% to debt securities, 39% to equity securities, 12% 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, except for $47.4 million as of December 31, 2013, 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, 2013 and 2012.

As of December 31, 2013	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ —	$ 161,272	$ 22,488	$ 183,760
International equity	—	75,872	—	75,872
Core bonds	—	191,506	—	191,506
High-yield bonds	—	20,796	—	20,796
Emerging market bonds	—	13,113	—	13,113
Combination debt/equity fund	—	58,336	—	58,336
Alternative investments	—	—	39,171	39,171
Real estate securities	—	—	24,022	24,022
Cash equivalents	—	3,241	—	3,241
Total Assets Measured at Fair Value	$ —	$ 524,136	$ 85,681	$ 609,817
As of December 31, 2012				
Assets:				
Domestic equity	$ —	$ 129,501	$ 18,493	$ 147,994
International equity	—	67,743	—	67,743
Core bonds	—	178,784	—	178,784
High-yield bonds	—	19,070	—	19,070
Emerging market bonds	—	14,276	—	14,276
Combination debt/equity fund	—	50,750	—	50,750
Alternative investments	—	—	45,535	45,535
Real estate securities	—	—	20,927	20,927
Cash equivalents	—	2,852	—	2,852
Total Assets Measured at Fair Value	$ —	$ 462,976	$ 84,955	$ 547,931

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, 2013 and 2012.

	Domestic Equity	Alternative Funds	Real Estate Securities	Net Balance
		(In Thousands)		
Balance as of December 31, 2012	$ 18,493	$ 45,535	$ 20,927	$ 84,955
Actual gain (loss) on plan assets:				
Relating to assets still held at the reporting date	3,845	1,936	3,307	9,088
Relating to assets sold during the period	—	826	—	826
Purchases, issuances and settlements, net	150	(9,126)	(212)	(9,188)
Balance as of December 31, 2013	$ 22,488	$ 39,171	$ 24,022	$ 85,681
Balance as of December 31, 2011	$ 15,375	$ 40,716	$ 18,848	$ 74,939
Actual gain (loss) on plan assets:				
Relating to assets still held at the reporting date	(25)	4,819	2,296	7,090
Relating to assets sold during the period	53	—	(27)	26
Purchases, issuances and settlements, net	3,090	—	(190)	2,900
Balance as of December 31, 2012	$ 18,493	$ 45,535	$ 20,927	$ 84,955

The following table provides the fair value of our post-retirement benefit plan assets and the corresponding level of hierarchy as of December 31, 2013 and 2012.

As of December 31, 2013	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ —	$ 64,080	$ —	$ 64,080
International equity	—	16,018	—	16,018
Core bonds	—	41,092	—	41,092
Cash equivalents	—	576	—	576
Total Assets Measured at Fair Value	$ —	$ 121,766	$ —	$ 121,766
As of December 31, 2012				
Assets:				
Domestic equity	$ —	$ 55,441	$ —	$ 55,441
International equity	—	14,037	—	14,037
Core bonds	—	36,738	—	36,738
Cash equivalents	—	577	—	577
Total Assets Measured at Fair Value	$ —	$ 106,793	$ —	$ 106,793

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:				
2014	$ 30.8		$ 2.9	
Expected benefit payments:				
2014	$ (35.4)	$ (2.8)	$ (8.7)	$ (0.2)
2015	(36.9)	(2.8)	(9.1)	(0.2)
2016	(39.2)	(2.8)	(9.3)	(0.2)
2017	(41.5)	(2.7)	(9.6)	(0.2)
2018	(44.5)	(2.7)	(9.8)	(0.2)
2019 – 2023	(257.9)	(12.8)	(49.7)	(1.0)

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 $6.9 million in 2013, $7.1 million in 2012 and $7.0 million in 2011.

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. In May 2011, Westar Energy shareholders approved an increase in the number of shares of common stock that may be granted under the LTISA Plan to 8.25 million shares from 5.0 million shares. As of December 31, 2013, awards of approximately 4.9 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,	2013	2012	2011
		(In Thousands)	
Compensation expense	$ 8,121	$ 7,203	$ 8,367
Income tax benefits related to stock-based compensation arrangements	3,212	2,849	3,309

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. In 2011, outstanding RSUs with only service requirements previously awarded to our former chief executive officer that were subject to forfeiture were modified to provide for the vesting upon his retirement in July 2011 of a prorated number of the RSUs based on the number of days from the grant date of the RSUs to his retirement date. In addition, outstanding RSUs with performance measures previously awarded to our former chief executive officer were modified to provide for the vesting on the scheduled vesting date, subject to the satisfaction of the applicable performance criteria, of a prorated number of the target RSUs based on the number of days from the grant date of the RSUs to his retirement date. We recorded compensation expense of $2.8 million in 2011 related to these modifications.

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 2013 valuation, inputs for expected volatility ranged from 15.0% to 23.5% and the risk-free interest rate was approximately 0.3%. For the 2012 valuation, inputs for expected volatility ranged from 17.6% to 33.6% and the risk-free interest rate was approximately 0.4%. 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, 2013, 2012 and 2011, our RSU activity for awards with only service requirements was as follows:

As of December 31,	2013		2012		2011	
	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	351.1	$ 25.47	368.5	$ 23.83	600.4	$ 21.50
Granted	139.6	31.06	131.0	27.82	284.1	26.30
Vested	(125.5)	23.22	(127.8)	23.34	(187.3)	23.50
Forfeited	(12.7)	28.35	(20.6)	24.40	(328.7)	24.37
Nonvested balance, end of year	352.5	28.38	351.1	25.47	368.5	23.83

Total unrecognized compensation cost related to RSU awards with only service requirements was $4.4 million as of December 31, 2013. 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, 2013, 2012 and 2011, was $3.7 million, $3.7 million and $4.8 million, respectively.

During the years ended December 31, 2013, 2012 and 2011, our RSU activity for awards with performance measures was as follows:

As of December 31,	2013		2012		2011	
	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	340.1	$ 29.20	324.2	$ 28.31	348.4	$ 24.98
Granted	134.4	31.54	122.3	28.84	244.4	31.26
Vested	(112.5)	28.29	(88.2)	25.46	(119.5)	24.12
Forfeited	(11.9)	30.45	(18.2)	29.00	(149.1)	28.72
Nonvested balance, end of year	350.1	30.35	340.1	29.20	324.2	28.31

As of December 31, 2013 and 2012, total unrecognized compensation cost related to RSU awards with performance measures was $4.0 million and $3.5 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, 2013, 2012 and 2011, was $2.3 million, $3.6 million and $3.6 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 551 shares of common stock for dividends in 2013, 666 shares in 2012 and 4,757 shares in 2011. Participants received common stock distributions of 3,456 shares in 2013, 1,461 shares in 2012 and 67,426 shares in 2011.

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.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2013	2012	2013	2012
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 176,891	$ 161,396	$ 11,020	$ 10,129
Service cost	6,835	6,062	206	191
Interest cost	7,562	7,537	413	411
Plan participants' contributions	—	—	696	608
Benefits paid[a]	(4,349)	(8,569)	(1,022)	(988)
Actuarial (gains) losses	(24,119)	9,815	(1,303)	669
Amendments	—	650	—	—
Benefit obligation, end of year	$ 162,820	$ 176,891	$ 10,010	$ 11,020
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 98,051	$ 80,727	$ 13	$ 4
Actual return on plan assets	13,166	11,764	—	—
Employer contributions	7,624	13,887	330	389
Plan participants' contributions	—	—	696	608
Benefits paid	(4,107)	(8,327)	(1,022)	(988)
Fair value of plan assets, end of year	$ 114,734	$ 98,051	$ 17	$ 13
Funded status, end of year	$ (48,086)	$ (78,840)	$ (9,993)	$ (11,007)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (237)	$ (243)	$ (614)	$ (625)
Noncurrent liability	(47,849)	(78,597)	(9,379)	(10,382)
Net amount recognized	$ (48,086)	$ (78,840)	$ (9,993)	$ (11,007)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 29,203	$ 64,535	$ 2,076	$ 3,643
Prior service cost	617	675	—	—
Transition obligation	—	—	—	1
Net amount recognized	$ 29,820	$ 65,210	$ 2,076	$ 3,644

[a] *In 2012 certain former employees received a one-time lump sum payment of their pension benefits. Our share of the payment totaled $4.9 million.*

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2013	2012	2013	2012
	(In Thousands)			
Pension Plans With a Projected Benefit Obligation in Excess of Plan Assets:				
Projected benefit obligation	$ 162,820	$ 176,891	$ —	$ —
Fair value of plan assets	114,734	98,051	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 137,459	$ 141,722	$ —	$ —
Fair value of plan assets	114,734	98,051	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 10,010	$ 11,020
Fair value of plan assets	—	—	16	13
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.11%	4.16%	4.70%	3.78%
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 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 2013	2012	2011
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 6,835	$ 6,062	$ 4,957
Interest cost	7,562	7,537	7,370
Expected return on plan assets	(7,373)	(6,577)	(5,904)
Amortization of unrecognized:			
Transition obligation, net	—	—	52
Prior service costs	58	6	16
Actuarial loss, net	5,421	5,366	3,586
Net periodic cost before regulatory adjustment	12,503	12,394	10,077
Regulatory adjustment[a]	(641)	(1,776)	(2,546)
Net periodic cost	$ 11,862	$ 10,618	$ 7,531
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain)/loss	$ (29,911)	$ 4,629	$ 29,124
Amortization of actuarial loss	(5,421)	(5,366)	(3,586)
Current year prior service cost	—	650	—
Amortization of prior service cost	(58)	(6)	(16)
Amortization of transition obligation	—	—	(52)
Total recognized in regulatory assets	$ (35,390)	$ (93)	$ 25,470
Total recognized in net periodic cost and regulatory assets	$ (23,528)	$ 10,525	$ 33,001
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	4.16%	4.55%	5.45%
Expected long-term return on plan assets	7.50%	7.50%	7.50%
Compensation rate increase	4.00%	4.00%	4.00%

Year Ended December 31,	Post-retirement Benefits 2013	2012	2011
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 206	$ 191	$ 165
Interest cost	413	411	458
Expected return on plan assets	—	—	—
Amortization of unrecognized:			
Transition obligation, net	—	57	58
Prior service costs	—	—	—
Actuarial loss, net	265	234	227
Net periodic cost before regulatory adjustment	884	893	908
Regulatory adjustment[a]	—	—	—
Net periodic cost	$ 884	$ 893	$ 908
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain)/loss	$ (1,303)	$ 669	$ (360)
Amortization of actuarial loss	(265)	(234)	(227)
Current year prior service cost	—	—	—
Amortization of prior service cost	—	—	—
Amortization of transition obligation	—	(57)	(58)
Total recognized in regulatory assets	$ (1,568)	$ 378	$ (645)
Total recognized in net periodic cost and regulatory assets	$ (684)	$ 1,271	$ 263
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	3.78%	4.10%	4.90%
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 into net periodic cost in 2014.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 2,987	$ 165
Prior service cost	58	—
Total	$ 3,045	$ 165

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,	2013	2012
Health care cost trend rate assumed for next year	7.5%	8.0%
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	2019	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	$ (9)	$ 9
Effect on post-retirement benefit obligation	(102)	97

Plan Assets

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. 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, 2013 and 2012.

As of December 31, 2013	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ —	$ 30,599	$ —	$ 30,599
International equity	—	36,868	—	36,868
Core bonds	—	26,926	—	26,926
Real estate securities	—	5,440	5,094	10,534
Commodities	—	5,245	—	5,245
Alternative investments	—	—	4,147	4,147
Cash equivalents	—	415	—	415
Total Assets Measured at Fair Value	$ —	$105,493	$ 9,241	$114,734
As of December 31, 2012				
Assets:				
Domestic equity	$ —	$ 24,305	$ —	$ 24,305
International equity	—	30,484	—	30,484
Core bonds	—	24,763	—	24,763
Real estate securities	—	4,972	4,541	9,513
Commodities	—	4,789	—	4,789
Alternative investments	—	—	3,900	3,900
Cash equivalents	—	297	—	297
Total Assets Measured at Fair Value	$ —	$ 89,610	$ 8,441	$ 98,051

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, 2013 and 2012.

	Real Estate Securities	Alternative Investments	Total
		(In Thousands)	
Balance as of December 31, 2012	$ 4,541	$ 3,900	$ 8,441
Actual gain (loss) on plan assets:			
Relating to assets still held at the reporting date	553	247	800
Balance as of December 31, 2013	$ 5,094	$ 4,147	$ 9,241
Balance as of December 31, 2011	$ 3,630	$ —	$ 3,630
Actual gain (loss) on plan assets:			
Relating to assets still held at the reporting date	(411)	23	(388)
Relating to assets sold during the period	755	—	755
Purchases, issuances and settlements, net	567	3,877	4,444
Balance as of December 31, 2012	$ 4,541	$ 3,900	$ 8,441

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:				
2014	$ 5.4		$ 0.6	
Expected benefit payments:				
2014	$ (4.6)	$ (0.2)	$ (0.6)	$ —
2015	(5.3)	(0.2)	(0.7)	—
2016	(6.1)	(0.2)	(0.8)	—
2017	(7.0)	(0.2)	(0.8)	—
2018	(7.8)	(0.2)	(0.8)	—
2019 – 2022	(53.0)	(1.3)	(4.4)	—

Savings Plan

Wolf Creek maintains a qualified 401(k) savings plan in which most of its employees participate. They match 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 $1.4 million in 2013, $1.3 million in 2012 and $1.3 million in 2011.

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, 2013, was as follows.

	Committed Amount
	(In Thousands)
2014	$ 258,293
2015	20,653
2016	25,762
Thereafter	7,463
Total amount committed	$ 312,171

Federal Clean Air Act

We must comply with the federal Clean Air Act, 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 Environmental Protection Agency (EPA), we are required to install, operate and maintain controls to reduce emissions found to cause or contribute to regional haze.

Under the federal Clean Air Act, the EPA sets National Ambient Air Quality Standards (NAAQS) for certain emissions considered harmful to public health and the environment, including two classes of PM, 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. KDHE proposed to designate portions of the Kansas City area nonattainment for the eight-hour ozone standard, which has the potential to impact our operations. The EPA has not acted on KDHE's proposed designation of the Kansas City area and it is uncertain when, or if, such a designation might occur. The Wichita area also exceeded the eight-hour ozone standard and could be designated nonattainment in the future potentially impacting our operations.

In December 2012, the EPA strengthened an existing NAAQS for one class of PM. By the end of 2014, the EPA anticipates making final attainment/nonattainment designations under this rule and expects to issue a final implementation rule. We are currently evaluating the rule and the impact it may have on our operations or consolidated financial results.

In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. We continue to communicate with our regulators regarding these standards and are currently evaluating what impact this could have on our operations. If we are required to install additional equipment to control emissions at our facilities, the revised NAAQS could have a material impact on our operations and consolidated financial results.

Environmental Projects

We will continue to make significant capital and operating expenditures at our power plants to reduce regulated emissions. The amount of these expenditures could change materially depending on the timing and nature of required investments, the specific outcomes resulting from existing regulations, new regulations, legislation and the manner in which we operate the plants. In addition to the capital investment, in the event we install new equipment, such equipment may cause us to incur significant increases in annual operating and maintenance expense and may reduce the net production, reliability and availability of the plants. The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. Additionally, our ability to access capital markets and the availability of materials, equipment and contractors may affect the timing and ultimate amount of such capital investments.

In comparison to a general rate review, the ECRR reduces the amount of time it takes to begin collecting in retail prices the costs associated with capital expenditures for qualifying environmental improvements. We are not allowed to use the ECRR to collect approximately $610.0 million of the projected capital investment associated with the environmental upgrades at La Cygne. 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 and to reflect cost reductions elsewhere. The new prices are expected to increase our annual retail revenues by approximately $30.7 million. For additional information regarding our abbreviated rate review, see Note 3, "Rate Matters and Regulation." To change our prices to collect increased operating and maintenance costs, we must file a general rate review with the KCC.

Air Emissions

The operation of power plants results in emissions of mercury, acid gases and other air toxics. In 2012, the EPA's Mercury and Air Toxics Standards (MATS) for power plants became effective, replacing the prior federal Clean Air Mercury Rule (CAMR) and requiring significant reductions in mercury, acid gases and other emissions. We expect to be compliant with the new standards by April 2016 as approved by KDHE. We continue to evaluate the new standards and believe that our related investment will be approximately $17.0 million.

Greenhouse Gases

Under regulations known as the Tailoring Rule, the EPA is regulating greenhouse gas (GHG) emissions from certain stationary sources. The regulations are being implemented pursuant to two federal Clean Air Act programs which impose recordkeeping and monitoring requirements and also mandate the implementation of best available control technology (BACT) for projects that cause a significant increase in GHG emissions (defined to be more than 75,000 tons or more per year or 100,000 tons or more per year,

depending on various factors). The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. We cannot at this time determine the impact of these regulations on our operations and consolidated financial results, but we believe the cost of compliance with the regulations could be material.

Renewable Energy Standard

Kansas law mandates that we maintain a minimum amount of renewable energy sources. Through 2015 net renewable generation capacity must be 10% of the average peak retail demand for the three prior years, subject to limited exceptions. This requirement increases to 15% for years 2016 through 2019 and 20% for 2020 and thereafter. In 2012, we began purchasing under 20-year supply contracts the renewable energy produced from approximately 370 MW of additional wind generation, which, together with existing facilities, supply contracts and renewable energy credits, will allow us to satisfy the net renewable generation requirement through 2015. With our agreement to purchase an additional 200 MW of installed design capacity from a wind generation facility beginning in late 2016, we expect to meet the increased requirements through 2020. If we are unable to meet future requirements, our operations and consolidated financial results could be adversely impacted.

EPA Consent Decree

As part of a 2010 settlement of a lawsuit filed by the Department of Justice on behalf of the EPA, we are installing selective catalytic reduction (SCR) equipment on one of three JEC coal units by the end of 2014, which we estimate will cost approximately $230.0 million. We are installing less expensive NOx reduction equipment on the other two units to satisfy other terms of the settlement. We plan to complete these projects in 2014 and recover the costs to install these systems through our ECRR, but such recovery remains subject to the approval of our regulators.

FERC Investigation

The Federal Energy Regulatory Commission (FERC) opened a non-public investigation of our use of transmission service between July 2006 and February 2008. In May 2009, FERC staff alleged that we improperly used secondary network transmission service to facilitate off-system wholesale power sales in violation of applicable FERC orders and Southwest Power Pool (SPP) tariffs and that we received $14.3 million of unjust profits through such activities. Based on our response to these allegations, FERC staff substantially revised downward its preliminary conclusions to allege that we received $0.9 million of unjust profits and failed to pay $0.8 million to the SPP for transmission service. As of December 31, 2012, we had recorded a liability of $1.6 million related to the potential settlement of this investigation and the risks of litigating this matter to a final outcome. We settled with FERC in January 2013 for $1.6 million.

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 2011 we revised the nuclear decommissioning study. Based on the study, our share of decommissioning costs, including decontamination, dismantling and site restoration, is estimated to be $296.2 million. This amount compares to the prior site study estimate of $279.0 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 $2.9 million in 2013, $3.2 million in 2012 and $3.2 million in 2011. We record our investment in the NDT fund at fair value, which approximated $175.6 million and $150.8 million as of December 31, 2013 and 2012, 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 pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee, calculated as one tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers, was $3.0 million in 2013, $3.6 million in 2012 and $3.1 million in 2011. We include these costs in fuel and purchased power expense on our consolidated statements of income. As of November 2013, a federal court of appeals ruled that the DOE must stop collecting this fee.

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. Wolf Creek has an on-site storage facility designed to hold all spent fuel generated at the plant through 2025 and believes it will be able to expand on-site storage as needed past 2025. We cannot predict when, or if, an alternative disposal site will be available to receive Wolf Creek's spent nuclear fuel and will continue to monitor this activity.

Wolf Creek disposes of most of its low-level radioactive waste at an existing third-party repository in Utah, which we expect will remain available to Wolf Creek. Wolf Creek also contracts with a waste processor to process, take title and dispose in another state most of the remainder of Wolf Creek's low-level radioactive waste. Should on-site waste storage be needed in the future, Wolf Creek has storage capacity on site adequate for about four years of plant operations and believes it will be able to expand that storage capacity if needed.

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. The $3.2 billion maximum recovery limit is not applicable, however, in the event of a "certified act of terrorism" as defined in the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007. In addition, we may be 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 31, 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, approximately $13.6 billion. This limit of liability consists of the maximum available commercial insurance of $375.0 million and the remaining $13.2 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 $34.4 million (our share is $16.1 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, 2013, our share of Wolf Creek's nuclear fuel commitments was approximately $41.3 million for uranium concentrates expiring in 2017, $6.1 million for conversion expiring in 2017, $109.0 million for enrichment expiring in 2025 and $41.1 million for fabrication expiring in 2023.

As of December 31, 2013, our coal and coal transportation contract commitments under the remaining terms of the contracts were approximately $900.6 million. The contracts are for plants that we operate and expire at various times through 2021.

As of December 31, 2013, our natural gas transportation contract commitments under the remaining terms of the contracts were approximately $117.2 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 purchase power agreements with the owners of five separate wind generation facilities with installed design capacities of 715 MW expiring in 2028 through 2036. Of the 715 MW under contract, 200 MW are associated with an agreement pursuant to which a generation provider is scheduled to deliver power beginning in 2016. 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 $68.2 million.

We have acquired rights to transmit a total of 306 MW of power. Agreements providing transmission capacity for approximately 200 MW expire in 2016 while the remaining 106 MW expire in 2022. As of December 31, 2013, we are committed to spend approximately $33.8 million over the remaining terms of these agreements.

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.

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,	2013	2012
	(In Thousands)	
Beginning ARO	$ 152,648	$ 142,508
Liabilities settled	(973)	(1,389)
Accretion expense	9,007	8,454
Revisions in estimated cash flows	—	3,075
Ending ARO	$ 160,682	$ 152,648

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 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, 2013 and 2012, we had $114.1 million and $129.0 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability.

15. LEGAL PROCEEDINGS

In 2011, we reached agreements with two former executive officers settling all contractual obligations related to their previous employment. The agreements required us to make payments totaling approximately $57.0 million, pay approximately $8.4 million for their legal fees and expenses, and release deferred stock for compensation shares. We also reversed the remaining approximately $22.0 million of previously accrued liabilities in 2011, which reduced selling, general and administrative expense reported on our consolidated statement of income.

We and our subsidiaries are involved in various other 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 Note 3, "Rate Matters and Regulation," and Note 13, "Commitments and Contingencies," for additional information.

16. COMMON AND PREFERRED STOCK

Common Stock

General

In 2011, Westar Energy shareholders approved an amendment to its Restated Articles of Incorporation to increase the number of shares of common stock authorized to be issued from 150.0 million to 275.0 million. As of December 31, 2013 and 2012, Westar Energy had issued 128.3 million shares and 126.5 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 2013 and 2012, Westar Energy issued 0.7 million shares and 0.8 million shares, respectively, through the DSPP and other stock-based plans operated under the LTISA Plan. As of December 31, 2013 and 2012, a total of 2.0 million shares and 1.5 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 the agreement. Westar Energy is required to settle such transactions within 24 months.

In March 2013, Westar Energy entered into a new, three-year sales agency financing agreement and master forward sale confirmation with a bank, similar to the sales agency financing agreement and master forward sale confirmation entered into in April 2010. 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 March 2013 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. Westar Energy must settle the forward sale transactions within 18 months of the date each transaction is entered. Under the terms of March 2013 agreements and April 2010 agreements, during the year ended December 31, 2013, Westar Energy entered into transactions with respect to an aggregate of approximately 2.5 million shares of common stock and settled 1.1 million shares that had a 2012 vintage. As of December 31, 2013, 3.1 million shares could have been settled. In February 2014, Westar Energy settled 0.3 million shares with a physical settlement amount of approximately $9.2 million.

Assuming physical share settlement of the approximately 12.1 million shares associated with all forward sale transactions as of December 31, 2013, Westar Energy would have received aggregate proceeds of approximately $358.3 million based on a weighted average forward price of $29.73 per share.

The forward sale transactions are entered into at market prices; therefore, the forward sale agreements have no initial fair value. Westar Energy does not receive any proceeds from the sale of common stock under the forward sale agreements until transactions are settled. Upon settlement, Westar Energy will record the forward sale agreements within equity. Except in specified circumstances or events that would require physical share settlement, Westar Energy is able to elect to settle any forward sale transactions by means of physical share, cash or net share settlement, and is also able to elect to settle the forward sale transactions in whole, or in part, earlier than the stated maturity dates. Currently, Westar Energy anticipates settling the forward sale transactions through physical share settlement. The shares under the forward sale agreements are initially priced when the transactions are entered into and are subject to certain fixed pricing adjustments during the term of the agreements. Accordingly, assuming physical share settlement, Westar Energy's net proceeds from the forward sale transactions will represent the prices established by the forward sale agreements applicable to the time periods in which physical settlement occurs.

Preferred Stock Redemption

In May 2012, Westar Energy provided an irrevocable notice of redemption to holders of all of Westar Energy's preferred shares. Accordingly, we reduced preferred equity to zero, recognized the obligation to redeem the preferred shares as a liability and recognized the redemption premium as a preferred stock dividend. Payment was due to holders of the preferred shares effective July 1, 2012. The table below shows the redemption amounts for all series of preferred stock.

Rate	Shares	Principal Outstanding	Call Price	Premium	Total Cost to Redeem
		(Dollars in Thousands)			
4.50%	121,613	$ 12,161	108.0%	$ 973	$ 13,134
4.25%	54,970	5,497	101.5%	82	5,579
5.00%	37,780	3,778	102.0%	76	3,854
	214,363	$ 21,436		$ 1,131	$ 22,567

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. Accounting guidance effective January 1, 2010, requires the primary beneficiary of a VIE to consolidate the VIE. The trusts holding our 8% interest in JEC, our 50% interest in La Cygne unit 2 and railcars we use to transport coal to some of our power plants 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, (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 50% interest in La Cygne unit 2 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.

Railcars

We leased railcars from an unrelated trust to transport coal to some of our power plants. We consolidated the trust as a VIE until the agreement expired in May 2013. As a result of deconsolidating the trust, property, plant and equipment of VIEs, net, and noncontrolling interests decreased $14.3 million.

We also lease railcars from another unrelated trust under an agreement that expires in November 2014. 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 railcars and lease them to us, and does not hold any other assets. We meet the requirements to be considered the primary beneficiary of this 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 the operation, maintenance and repair of the railcars and our ability to exercise a purchase option at the end of the agreements 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 railcars at the end of the agreements is greater than the fixed amount. Our agreement with this trust also includes renewal options during which time we would pay a fixed amount of rent. We have the potential to receive benefits from the trust during the renewal period if the fixed amount of rent is less than the amount we would be required to pay under a new agreement.

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,	2013	2012
	(In Thousands)	
Assets:		
Property, plant and equipment of variable interest entities, net	$ 296,626	$ 321,975
Regulatory assets[a]	6,792	5,810
Liabilities:		
Current maturities of long-term debt of variable interest entities	$ 27,479	$ 25,942
Accrued interest[b]	3,472	3,948
Long-term debt of variable interest entities, net	194,802	222,743

(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. These leases have various terms and expiration dates ranging from one to 20 years.

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:	
2011	$ 17,577
2012	17,080
2013	16,484
Future commitments:	
2014	$ 14,384
2015	11,980
2016	10,232
2017	8,383
2018	5,248
Thereafter	15,361
Total future commitments	$ 65,588

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. The lease term for vehicles is from two to eight years depending on the type of vehicle. Computer equipment has a lease term of three to five years.

In 2012, we signed an agreement to lease electrical facilities that connect a wind generating facility to the transmission system. The agreement extends through August 2032, at which time it may be extended or we may exercise an option to purchase the line. The terms of the agreement meet the criteria of a capital lease; therefore, we recorded an $8.3 million capital lease.

Assets recorded under capital leases, including the 2012 lease described above presented as generation plant, are listed below.

As of December 31,	2013	2012
	(In Thousands)	
Vehicles	$ 12,141	$ 12,594
Computer equipment	1,758	1,423
Generation plant	48,346	48,346
Accumulated amortization	(10,493)	(6,928)
Total capital leases	$ 51,752	$ 55,435

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)
2014	$ 6,464
2015	5,891
2016	5,179
2017	4,711
2018	4,664
Thereafter	72,135
	99,044
Amounts representing imputed interest	(44,992)
Present value of net minimum lease payments under capital leases	54,052
Less: Current portion	3,249
Total long-term obligation under capital leases	$ 50,803

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.

2013	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues[a]	$ 546,212	$ 569,589	$ 694,974	$ 559,878
Net income [a]	53,256	69,451	135,095	43,061
Net income attributable to Westar Energy, Inc.[a]	51,144	67,188	133,125	41,062
Per Share Data[a]:				
Basic:				
Earnings available	$ 0.40	$ 0.53	$ 1.04	$ 0.32
Diluted:				
Earnings available	$ 0.40	$ 0.52	$ 1.04	$ 0.32
Cash dividend declared per common share	$ 0.34	$ 0.34	$ 0.34	$ 0.34
Market price per common share:				
High	$ 33.35	$ 34.96	$ 34.31	$ 32.56
Low	$ 28.59	$ 30.13	$ 29.79	$ 29.95

[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.*

2012	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues[a]	$ 475,677	$ 566,262	$ 695,758	$ 523,772
Net income[a]	29,237	64,462	141,067	47,695
Net income attributable to common stock[a]	27,282	61,361	139,281	45,607
Per Share Data[a]:				
Basic:				
Earnings available	$ 0.21	$ 0.48	$ 1.10	$ 0.36
Diluted:				
Earnings available	$ 0.21	$ 0.48	$ 1.09	$ 0.36
Cash dividend declared per common share	$ 0.33	$ 0.33	$ 0.33	$ 0.33
Market price per common share:				
High	$ 29.13	$ 30.17	$ 33.04	$ 30.29
Low	$ 27.12	$ 26.80	$ 28.96	$ 27.33

[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 is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission 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 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.

In 2013 we completed the implementation a new Enterprise Resource Planning (ERP) system for our financial, accounting, and supply chain functions that changes our business and financial transaction processes used in those functions. This implementation represents a change in our internal control over financial reporting. In connection with this implementation, we updated our internal controls over financial reporting, as necessary, to accommodate modifications to our business processes and accounting procedures.

There were no changes in our internal control over financial reporting during the three months ended December 31, 2013, that have 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 Annual 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

None.

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 2014 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (2014 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 2014 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 caption *Election of Directors – Corporate Governance Matters* in our 2014 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 2014 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 2014 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 2014 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 2014 Proxy Statement under the caption of *Ratification and Confirmation of Deloitte and Touche LLP as Our Independent Registered Public Accounting Firm for 2014* 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, 2013 and 2012
Consolidated Statements of Income for the years ended December 31, 2013, 2012 and 2011
Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011
Consolidated Statements of Changes in Equity for the years ended December 31, 2013, 2012 and 2011
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)	Amendment to Sales Agency Financing Agreement, dated May 26, 2010, among Westar Energy, Inc., BNY Mellon Capital Markets, LLC, and The Bank of New York Mellon (filed as Exhibit 1(a) to the Form 10-Q for the period ended June 30, 2012 filed on August 7, 2012)	I
1(b)	Second Amendment to Sales Agency Financing Agreement, dated May 9, 2012, among Westar Energy, Inc., BNY Mellon Capital Markets, LLC, and The Bank of New York Mellon (filed as Exhibit 1(b) to the Form 10-Q for the period ended March 31, 2012 filed on May 9, 2012)	I
1(c)	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)	Form of Certificate of Designations for 7.5% Convertible Preference Stock (filed as Exhibit 99.4 to the Form 8-K filed on November 17, 2000)	I
3(j)	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(k)	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(l)	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(m)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc.	#
3(n)	Form of Certificate of Decertification of Preference Shares	#
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)	Fortieth Supplemental Indenture dated May 15, 2007 between Westar Energy, Inc. and The Bank of New York Trust Company, N.A. (as successor to Harris Trust and Savings Bank) to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.16 to the Form 8-K filed on May 16, 2007)	I
4(s)	Form of First Mortgage Bonds, 6.10% Series Due 2047 (contained in Exhibit 4(r))	I
4(t)	Forty-First Supplemental Indenture, dated as of November 25, 2008 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 November 24, 2008)	I
4(u)	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(v)	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(w)	Form of Forty-Third Supplemental Indenture, dated as of March 28, 2013, by and between 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(x)	Form of Forty-Fourth Supplemental Indenture, dated as of August 19, 2013, by and between 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(y)	Fifty-Eighth Supplemental Indenture, dated as of February 12, 2013, by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Richard Tarnas (filed as Exhibit 4.1 to the Form 8-K filed on February 15, 2013)	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)	Long-Term Incentive and Share Award Plan (filed as Exhibit 10(a) to the Form 10-Q for the period ended June 30, 1996 filed on August 14, 1996)*	I
10(c)	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(d)	Resolutions of the Westar Energy, Inc. Board of Directors regarding Non-Employee Director Compensation, approved on September 2, 2004 (filed as Exhibit 10.1 to the Form 8-K filed on December 17, 2004)*	I
10(e)	Form of Change in Control Agreement (filed as Exhibit 10.1 to the Form 8-K filed on January 26, 2006)*	I
10(f)	Westar Energy, Inc. Form of Restricted Share Units Award (filed as Exhibit 10(aq) to the Form 10-K for the period ended December 31, 2009, filed on February 25, 2010)	I
10(g)	Westar Energy, Inc. Form of Performance Based Restricted Share Units Award (filed as Exhibit 10(ar) to the Form 10-K for the period ended December 31, 2009 filed on February 25, 2010)	I
10(h)	Westar Energy, Inc. Form of First Transition Performance Based Restricted Share Units Award (filed as Exhibit 10(as) to the form 10-K for the period ended December 31, 2009 filed on February 25, 2010)	I
10(i)	Westar Energy, Inc. Form of Second Transition Performance Based Restricted Share Units Award (filed as Exhibit 10(at) to the Form 10-K for the period ended December 31, 2009 filed on February 25, 2010)	I
10(j)	Form of Amended and Restated Change in Control Agreement with Officers of Westar Energy, Inc. (filed as Exhibit 10(au) to the Form 10-K for the period ended December 31, 2009 filed on February 25, 2010)	I
10(k)	Westar Energy, Inc. Retirement Benefit Restoration Plan (filed as Exhibit 10.1 to the Form 8-K filed on April 2, 2010)	I
10(l)	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(m)	Amendment to Long-Term Incentive and Share Award Plan (filed as Exhibit 10 to the Form 8-K filed on May 6, 2011)	I
10(n)	Amendment to Restricted Share Units Awards between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10.1 to the Form 8-K filed on July 6, 2011)	I
10(o)	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(p)	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(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

10(v)	Second Extension Agreement dated as of February 14, 2014, among Westar Energy, Inc. and several banks and other forward institutions or entities from time to time parties to the Agreement	#
12(a)	Computations of Ratio of Consolidated Earnings to Fixed Charges	#
12(b)	Computation of Ratio of Earnings to Fixed Charges for the Three Months Ended March 31, 2007 (filed as Exhibit 12.1 to the Form 8-K filed on May 10, 2007)	I
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 Accounting 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, 2011				
Allowances deducted from assets for doubtful accounts	$5,729	$8,774	$(7,119)	$7,384
Year ended December 31, 2012				
Allowances deducted from assets for doubtful accounts	$7,384	$6,617	$(9,085)	$4,916
Year ended December 31, 2013				
Allowances deducted from assets for doubtful accounts	$4,916	$7,039	$(7,359)	$4,596

[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 26, 2014

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 26, 2014
/s/ ANTHONY D. SOMMA (Anthony D. Somma)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	February 26, 2014
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 26, 2014
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 26, 2014
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 26, 2014
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 26, 2014
/s/ RICHARD L. HAWLEY (Richard L. Hawley)	Director	February 26, 2014
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 26, 2014
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	February 26, 2014
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 26, 2014
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	February 26, 2014
/s/ S. CARL SODERSTROM JR. (S. Carl Soderstrom Jr.)	Director	February 26, 2014

SHAREHOLDER INFORMATION AND ASSISTANCE:

Westar Energy's Shareholder Services department offers personalized service to the company's individual shareholders. We are the transfer agent for Westar Energy common stock. Shareholder Services provides information and assistance to shareholders 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 us 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.

Please visit our website at **WestarEnergy.com**. Registered shareholders can easily access their shareholder account information online by clicking on the **Shareholder Sign-in button,** found on the Investors page of our website.

CONTACTING SHAREHOLDER SERVICES

TELEPHONE

Toll-free:	800-527-2495
In the Topeka area:	785-575-6394
Fax:	785-575-1796

ADDRESS

Westar Energy, Inc.
Shareholder Services
P.O. Box 750320
Topeka, KS 66675-0320

E-MAIL ADDRESS

shareholders@WestarEnergy.com

Please include a daytime telephone number in all correspondence.

CO-TRANSFER AGENT

Continental Stock Transfer & Trust Company
17 Battery Place, 8th Floor
New York, NY 10004

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 2014, 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, 2013, were included as exhibits to Westar Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2013, that was filed with the Securities and Exchange Commission.

DIRECTORS:

CHARLES Q. CHANDLER IV (60)
Chairman of the Board
Director since 1999
Chairman since 2002
Chairman of the Board
and Chief Executive Officer
INTRUST Bank, NA
Wichita, Kansas

MOLLIE HALE CARTER (51)
Director since 2003
Chairman of the Board, President
and Chief Executive Officer
Sunflower Banks, Inc.
Salina, Kansas
Committees: Compensation, Finance

R.A. EDWARDS III (68)
Director since 2001
Chairman of the Board
First National Bank
of Hutchinson
Hutchinson, Kansas
Committees: Audit, Nominating and Corporate Governance

JERRY B. FARLEY (67)
Director since 2004
President
Washburn University
Topeka, Kansas
Committees: Audit, Nominating and Corporate Governance

RICHARD L. HAWLEY (64)
Director since 2011
Executive Vice President and
Chief Financial Officer (Retired)
Nicor, Inc.
Bellevue, Washington
Committees: Audit, Compensation

B. ANTHONY ISAAC (61)
Director since 2003
Senior Vice President
Hyatt Hotels Corporation
Wichita, Kansas
Committees: Compensation, Finance

ARTHUR B. KRAUSE (73)
Director since 2003
Executive Vice President and
Chief Financial Officer (Retired)
Sprint Corporation
Naples, Florida
Committees: Audit, Finance

SANDRA A.J. LAWRENCE (56)
Director since 2004
Executive Vice President and
Chief Financial Officer
Children's Mercy Hospital
Kansas City, Missouri
Committees: Compensation, Nominating and Corporate Governance

MICHAEL F. MORRISSEY (71)
Director since 2003
Managing Partner (Retired)
Ernst & Young LLP
Naples, Florida
Committees: Audit, Compensation

MARK A. RUELLE (52)
Director since 2011
President and Chief Executive Officer
Westar Energy, Inc.
Topeka, Kansas

S. CARL SODERSTROM, JR. (60)
Director since 2010
Senior Vice President and
Chief Financial Officer (Retired)
ArvinMeritor
Longwood, Florida
Committees: Finance; Nominating and Corporate Governance

OFFICERS:

MARK A. RUELLE (52)
21 years of service
Director, President and Chief
Executive Officer

DOUGLAS R. STERBENZ (50)
16 years of service
Executive Vice President and
Chief Operating Officer

ANTHONY D. SOMMA (50)
19 years of service
Senior Vice President, Chief
Financial Officer and Treasurer

GREGORY A. GREENWOOD (48)
20 years of service
Senior Vice President, Strategy

BRUCE A. AKIN (49)
26 years of service
Vice President, Power Delivery

JERL L. BANNING (53)
5 years of service
Vice President, Human Resources
and Information Technology

JEFFREY L. BEASLEY (56)
36 years of service
Vice President, Customer Care

JOHN T. BRIDSON (44)
20 years of service
Vice President, Generation

KELLY B. HARRISON (55)
32 years of service
Vice President, Transmission

LARRY D. IRICK (57)
14 years of service
Vice President, General Counsel
and Corporate Secretary

JEFFREY L. MARTIN (43)
20 years of service
Vice President, Regulatory Affairs

KEVIN L. KONGS (52)
24 years of service
Vice President, Controller

MICHEL' PHILIPP COLE (51)
10 years of service
Vice President, Corporate
Communications and Public Affairs

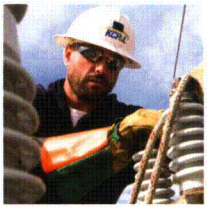
Ages and years of service are as of March 31, 2014.

Westar Energy®

Taking energy to heart.

P.O. Box 889, Topeka, Kansas 66601-0889 • **WestarEnergy.com**

2013 ANNUAL REPORT



A TRUSTED ENERGY PARTNER

GREAT PLAINS ENERGY

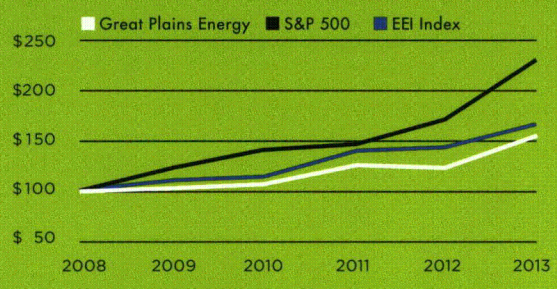
Selected Financial Data

Year Ended December 31	2013	2012	2011	2010	2009
(Dollars in millions except per share amounts)					
GREAT PLAINS ENERGY					
Operating revenues	**$ 2,446**	$ 2,310	$ 2,318	$ 2,256	$ 1,965
Income from continuing operations [a]	**$ 250**	$ 200	$ 174	$ 212	$ 152
Net income attributable to Great Plains Energy	**$ 250**	$ 200	$ 174	$ 212	$ 150
Basic earnings per common share from continuing operations	**$ 1.62**	$ 1.36	$ 1.27	$ 1.55	$ 1.16
Basic earnings per common share	**$ 1.62**	$ 1.36	$ 1.27	$ 1.55	$ 1.15
Diluted earnings per common share from continuing operations	**$ 1.62**	$ 1.35	$ 1.25	$ 1.53	$ 1.15
Diluted earnings per common share	**$ 1.62**	$ 1.35	$ 1.25	$ 1.53	$ 1.14
Total assets at year end	**$ 9,795**	$ 9,647	$ 9,118	$ 8,818	$ 8,483
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities)	**$ 3,517**	$ 3,020	$ 3,544	$ 3,428	$ 3,214
Cash dividends per common share	**$ 0.8825**	$ 0.855	$ 0.835	$ 0.83	$ 0.83
SEC ratio of earnings to fixed charges	**2.75**	2.31	2.03	2.28	1.81
KCP&L					
Operating revenues	**$ 1,671**	$ 1,580	$ 1,558	$ 1,517	$ 1,318
Net income	**$ 169**	$ 142	$ 136	$ 163	$ 129
Total assets at year end	**$ 6,839**	$ 6,704	$ 6,292	$ 6,026	$ 5,702
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities)	**$ 2,312**	$ 1,902	$ 1,915	$ 1,780	$ 1,780
SEC ratio of earnings to fixed charges	**2.76**	2.58	2.52	2.86	2.44

(a) This amount is before loss from discontinued operations, net of income taxes, of $1.5 million in 2009.

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, 2008, in Great Plains Energy common stock, S&P 500 Index and EEI Index

Great Plains Energy Operating Revenues
(Dollars in millions)

We remain committed to being a trusted energy partner for our shareholders, customers and the communities we serve.

TRUSTED ENERGY PARTNER

Customers
Want to interact with a utility that provides reliable source of clean, affordable energy

Employees
Want to work for a reliable best-in-class company that performs and cares

Shareholders
Want to invest in a company that delivers reliable financial performance

TO OUR SHAREHOLDERS

In 2013, Great Plains Energy continued down a determined path to improve our total shareholder return. Our mantra of "Execute, Execute, Execute" focused on our ability to achieve operational excellence, manage costs and significantly reduce regulatory lag. I am proud to report that we delivered on this goal. Our 2013 total shareholder return of 24 percent placed us in Tier 1 of investor-owned utilities, which compares to a 13 percent return for the Edison Electric Institute Index.

Solid financial results provided the foundation for our strong performance in 2013. Earnings per share for the year were $1.62 which is near the top end of the earnings guidance range we established in February 2013. Our cost management efforts included negotiating a more favorable coal transportation contract, reducing headcount through attrition by approximately 4 percent and focusing on lower procurement costs through our supply chain transformation initiative. With customer demand growth, a continued focus on diligently managing costs, combined with new customer rates and recovery mechanisms, we reduced regulatory lag on our allowed return on equity to nearly 50 basis points, down from 170 basis points in 2012.

Our strong performance and financial outlook allowed us to increase our common stock dividend for the third consecutive year to $0.92 per share on an annual basis, a nearly 6 percent increase. As we look ahead, we are targeting continued dividend growth of 4 to 6 percent and a dividend payout ratio range of 55 to 70 percent of earnings through 2016 and 60 to 70 percent longer term. These targets reflect confidence in our business plan and our belief that a competitive, sustainable and increasing dividend is an important driver of total shareholder returns.

Other recent achievements we are very proud of include:

- Receiving the Power Plant Operational Excellence & Stewardship Award from GP Strategies for our Iatan coal-fired generating station. The award recognized Iatan for its efficiency and environmental stewardship, including efforts to restore 106 acres of Missouri River wetlands that house rare wildlife, such as peregrine falcons and bald eagles;

Stable Regulated Customer Base

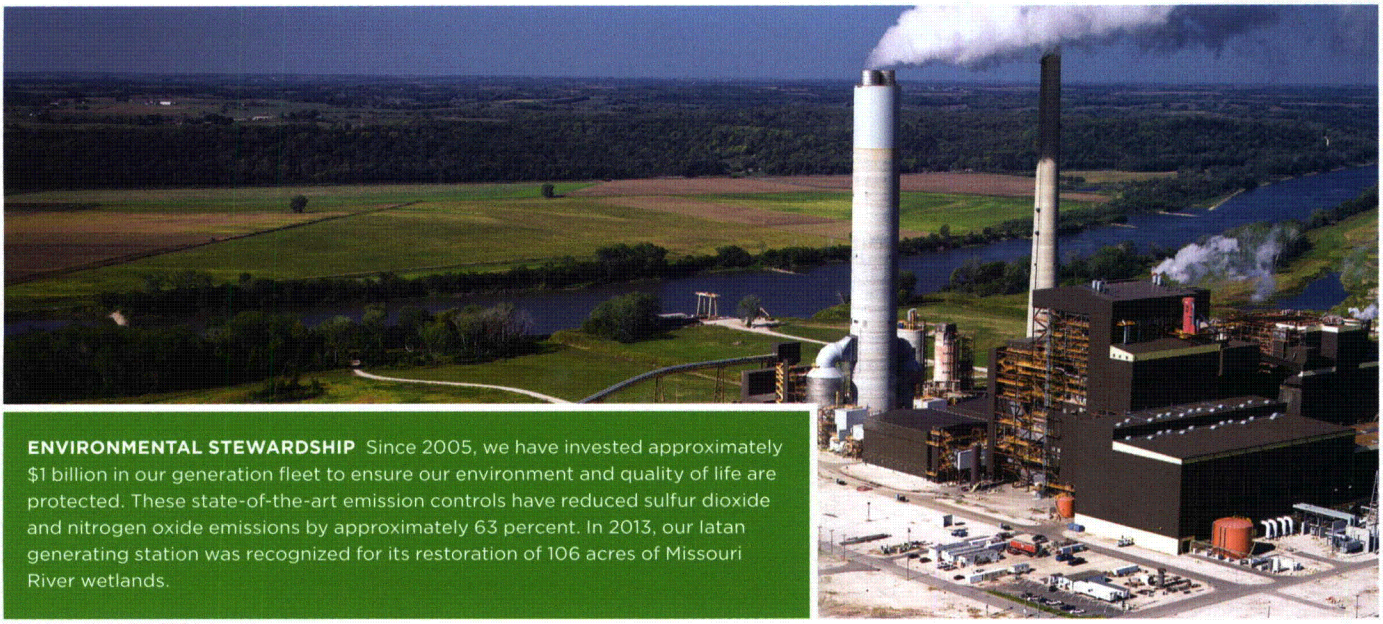
Number of Customers by Segment

(Year-end 2013)

- Delivering the best coal fleet equivalent availability factor, during our peak months, in over five years. This metric measures the percentage of time our plants are available to generate power during a period of time;
- Receiving the ReliabilityOne™ award from the PA Consulting Group for the Plains Region for the seventh consecutive year. This award is given annually to utility companies that achieve outstanding reliability performance and excel at delivering reliable electric service to customers;
- Further enhancing our regional environmental sustainability leadership by securing an additional 400 megawatts of wind capacity that will increase our renewable supply portfolio to approximately 1,000 megawatts of wind, hydroelectric, landfill gas and solar power;
- Obtaining the regulatory approvals to successfully transfer our two Southwest Power Pool regional transmission projects to Transource, our joint venture with American Electric Power that we believe is one of the most well-positioned companies in the country to compete in the growing transmission market; and
- Achieving an improved credit profile by receiving a ratings upgrade from Moody's Investor Service and revised outlook from Standard & Poor's to Positive from Stable. We believe this is a testament to our objective to strengthen key credit metrics while maintaining a growing and competitive dividend.

2013 also marked the five-year anniversary of our acquisition of Aquila, subsequently renamed KCP&L Greater Missouri Operations Company (GMO). Since completing the acquisition, we have realized more than $760 million in synergies, which significantly exceeded our original expectations.

We have taken steps to reduce uncertainty in our business and to deliver stable and reliable total shareholder returns. While there is more work to be done, our performance in 2013 demonstrates our commitment to be a trusted energy partner for our shareholders, customers and the communities we serve.



ENVIRONMENTAL STEWARDSHIP Since 2005, we have invested approximately $1 billion in our generation fleet to ensure our environment and quality of life are protected. These state-of-the-art emission controls have reduced sulfur dioxide and nitrogen oxide emissions by approximately 63 percent. In 2013, our Iatan generating station was recognized for its restoration of 106 acres of Missouri River wetlands.

RENEWABLE ENERGY KCP&L was the first regulated electric utility to own and operate a commercial-scale wind facility in Kansas. With the initial turbines completed in 2006, our Spearville Wind Energy Facility has grown to 148.5 megawatts of capacity. In addition to Spearville, our renewable energy portfolio includes nearly 1,000 megawatts of wind, hydroelectric, landfill gas and solar power.

LOOKING AHEAD

As we look to the future, our management team and employees are excited about the opportunities we have to further strengthen our company.

We continue to believe energy efficiency and demand side management solutions will play a significant role as customer behavior evolves. We are preparing for a future in which customer engagement in new and emerging energy efficient solutions will continue to deepen, and we are working to educate customers about their options and be responsive to what they need, want and expect from us.

Our comprehensive suite of energy efficiency solutions is an excellent example of how we are working to enhance our customers' experience. We have requested approval from the Missouri Public Service Commission to expand our energy efficiency programs to all of our Missouri customers under the Missouri Energy Efficiency Investment Act. Once the request is approved, the programs are expected to enhance customer service, generate greater shareholder returns and increase reserve planning flexibility – a true win, win, win.

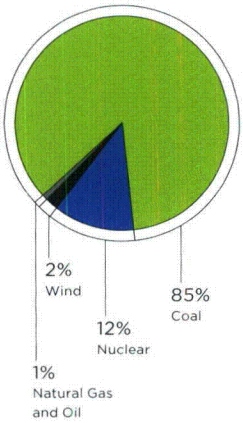
Kansas City's central location, robust distribution infrastructure and diverse economy are assets that position us well for steady, long-term growth. In 2013, the region had the highest number of single family housing permits issued since 2007 and unemployment in the area reached its lowest level in more than five years, remaining below the national average. These and other factors resulted in a five-year high for customer demand growth.

Environmental stewardship and a reasonable transition to a cleaner, more diversified generation fleet remain a focus. Since 2005, we have reduced sulfur dioxide and nitrogen oxide emissions by approximately 63 percent and our commitment to environmental stewardship remains steadfast with the installation of state-of-the-art environmental control equipment at our La Cygne generating station. The La Cygne environmental upgrade is the focus of our near-term environmental capital spend, and construction on this project remains on budget and on schedule for completion in 2015. Once completed, approximately 72 percent of our coal fleet will have emission-reducing scrubbers installed and all of our large

Generation Mix

Net MWhs Generated by Fuel Type

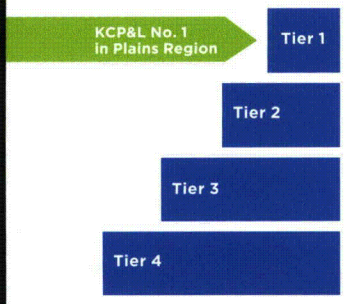
(2013)



ECONOMIC DEVELOPMENT Customers are attracted to our competitive rates and reputation for reliability. We worked closely with BNSF Railway when it built a new state-of-the-art regional intermodal facility, and Ford Motor Co. as it completed a $1.1 billion expansion of its Kansas City Assembly Plant to meet demand for the F-150 truck and begin production of the Transit van.

Reliability a Key Focus

KCP&L Receives ReliabilityOne Award for Seventh Consecutive Year



base load coal units are expected to be in compliance with existing environmental rules and regulations. We plan to file rate cases in Missouri and Kansas in 2015 to add the remainder of this investment to our rate base. Our proactive investments in environmental control technology, renewables and energy efficiency provide us with the flexibility and time to make prudent longer term resource decisions, including decisions about our remaining units, that meet the needs of our customers, regulators and shareholders.

Our success in reducing the expense lag on our allowed return can be partly attributed to our implementation of mechanisms that more closely track costs. We continue to push for riders or trackers to recover costs that are not controllable in a timelier manner. For example, we have requested authorization from the Missouri Public Service Commission to implement an Accounting Authority Order (AAO) for transmission costs. If granted, the AAO will track incremental transmission costs until the next general rate case proceedings, at which time recovery of "tracked" transmission costs will be addressed.

In closing, we plan to continue delivering competitive total shareholder returns by meeting our customers' evolving needs, striving for operational excellence, diligently managing costs and minimizing regulatory lag. We remain committed to being a trusted energy partner for our shareholders, customers and the communities we serve. As the future unfolds, we look forward to traveling down this path with our dedicated investors.

Sincerely,

TERRY BASSHAM
Chairman of the Board, President and Chief Executive Officer

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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2013

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 ☒ No ☐ Kansas City Power & Light Company Yes ☐ No ☒

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 ☒ Kansas City Power & Light Company Yes ☐ No ☒

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 ☒ No ☐ Kansas City Power & Light Company Yes ☒ 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 ☒ No ☐ Kansas City Power & Light Company Yes ☒ 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 ☒ Kansas City Power & Light Company ☒

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	☒	Accelerated filer	☐
	Non-accelerated filer	☐	Smaller reporting company	☐
Kansas City Power & Light Company	Large accelerated filer	☐	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 Exchange Act).

Great Plains Energy Incorporated Yes ☐ No ☒ Kansas City Power & Light Company Yes ☐ No ☒

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, 2013) was approximately $3,463,459,186. 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 25, 2014, Great Plains Energy Incorporated had 153,883,693 shares of common stock outstanding.

On February 25, 2014, 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 2014 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
BART	Best available retrofit technology
Board	Great Plains Energy Board of Directors
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
Company	Great Plains Energy Incorporated and its subsidiaries
Companies	Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries
CSAPR	Cross-State Air Pollution Rule
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
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 subsidiaries
IRS	Internal Revenue Service
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
KCP&L Receivables Company	Kansas City Power & Light Receivables Company, a wholly owned subsidiary of KCP&L
KDHE	Kansas Department of Health and Environment
kV	Kilovolt
KW	Kilowatt
kWh	Kilowatt hour
MACT	Maximum achievable control technology
MATS	Mercury and Air Toxics Standards
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations

Abbreviation or Acronym	Definition
MDNR	Missouri Department of Natural Resources
MEEIA	Missouri Energy Efficiency Investment Act
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
NAAQS	National Ambient Air Quality Standard
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
PCB	Polychlorinated biphenyls
ppm	Parts per million
PRB	Powder River Basin
QCA	Quarterly Cost Adjustment
RTO	Regional Transmission Organization
SCR	Selective catalytic reduction
SEC	Securities and Exchange Commission
SERP	Supplemental Executive Retirement Plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Syncora	Syncora Guarantee, Inc.
TCR	Transmission Congestion Right
Transource	Transource Energy, LLC and its subsidiaries, 13.5% owned by GPETHC
Transource Missouri	Transource Missouri, LLC, a wholly owned subsidiary of Transource
WCNOC	Wolf Creek Nuclear Operating Corporation
Westar	Westar Energy, Inc., a Kansas utility company
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 operations or active subsidiaries 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.
- GPE Transmission Holding Company, LLC (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. 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 23 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 830,800 customers located in western Missouri and eastern Kansas. Customers include approximately 730,800 residences, 97,400 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 103%, 108% and 115% of Great Plains Energy's net income in 2013, 2012 and 2011, 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, the Southwest Power Pool, Inc. (SPP) and the North American Electric Reliability Corporation (NERC). 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.

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. In this regard, electric utility competes with owners of other generating stations and other power suppliers, principally utilities in its region, 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 6,600 MWs of generating capacity. The projected peak summer demand for 2014 is approximately 5,600 MWs. Electric utility expects to meet its projected capacity requirements for the foreseeable future with its generation assets, power and capacity purchases or new capacity additions.

KCP&L and GMO are members of the SPP. The SPP is a Regional Transmission Organization (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 and capacity, 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.

In March 2014, the SPP is scheduled to launch its Integrated Marketplace. Similar to other RTO or Independent System Operator (ISO) markets currently operating, this marketplace will determine which generating units among market participants should run, within the operating constraints of a unit, at any given time for maximum cost-effectiveness. It will also provide participants with greater access to reserve electricity, improve regional balancing of supply and demand, and facilitate the integration of renewable resources. KCP&L and GMO expect the Integrated Marketplace to potentially change the way their plants are dispatched. 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 once the Integrated Marketplace begins operations.

Fuel

The principal fuel sources for electric utility's electric generation are coal and nuclear fuel. It is expected, with normal weather, that approximately 97% of 2014 generation will come from these sources with the remainder provided by wind, natural gas and oil. The actual 2013 and estimated 2014 fuel mix and delivered cost in cents per net kWh generated are outlined in the following table.

	Fuel Mix [a]		Fuel cost in cents per net kWh generated	
	Estimated	Actual	Estimated	Actual
Fuel	2014	2013	2014	2013
Coal	82 %	85 %	2.02	2.14
Nuclear	15	12	0.77	0.79
Natural gas and oil	1	1	9.89	9.41
Wind	2	2	—	—
Total Generation	100 %	100 %	1.89	1.99

[a] Fuel mix based on percent of net MWhs generated.

GMO's retail rates and KCP&L's retail rates in Kansas contain certain fuel recovery mechanisms. KCP&L's Missouri retail rates do not contain a fuel recovery mechanism. To the extent the price of fuel or purchased power increases significantly, or if electric utility's lower cost units do not meet anticipated availability levels, Great Plains Energy's net income may be adversely affected unless and until the increased cost could be reflected in KCP&L's Missouri retail rates.

Coal

During 2014, 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 75% of the projected coal requirements for 2014, approximately 40% for 2015 and approximately 20% for 2016. 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 2014 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 2014 through 2018. 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 September 2016 and approximately 70% after that date through March 2021. 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, 2013, GMO had hedged approximately 40% and 6% of its expected on-peak natural gas generation and natural gas equivalent purchased power price exposure for 2014 and 2015, respectively.

Purchased Capacity and Power

KCP&L and GMO have distinct rate and dispatching areas. As a result, KCP&L and GMO do not joint-dispatch their respective generation. KCP&L purchases power to meet its customers' needs when it does not have sufficient available generation or when the cost of purchased power is less than KCP&L's cost of generation or to satisfy firm power commitments or renewable energy standards. KCP&L has long-term power purchase agreements for approximately 287 MWs of wind and hydroelectric generation which expire in 2023 through 2032. GMO has long-term power purchase agreements for approximately 159 MWs of wind generation which expire in 2016 through 2032. Additionally, KCP&L and GMO have each entered into power purchase agreements for approximately 200 MW of wind generation to begin in 2016 and expire in 2036. 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. Electric utility's purchased power, as a percentage of MWh requirements, averaged approximately 14% over the last three years.

Environmental Matters

See Note 15 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 514,700 customers located in western Missouri and eastern Kansas. Customers include approximately 453,900 residences, 58,700 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, 2013, Great Plains Energy and KCP&L had 2,964 employees, including 1,861 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, 2016), 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 a responsible position with the Company in the positions 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, 2014, 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]	53	Chairman of the Board, President and Chief Executive Officer - Great Plains Energy and KCP&L	2005
Scott H. Heidtbrink [b]	52	Executive Vice President and Chief Operating Officer - KCP&L	2008
James C. Shay [c]	50	Senior Vice President - Finance and Strategic Development and Chief Financial Officer - Great Plains Energy and KCP&L	2010
Kevin E. Bryant [d]	38	Vice President - Investor Relations and Strategic Planning and Treasurer - Great Plains Energy and KCP&L	2006
Charles A. Caisley [e]	41	Vice President - Marketing and Public Affairs - Great Plains Energy and KCP&L	2011
Michael L. Deggendorf [f]	52	Senior Vice President - Corporate Services - KCP&L	2005
Ellen E. Fairchild [g]	52	Vice President, Corporate Secretary and Chief Compliance Officer - Great Plains Energy and KCP&L	2010
Heather A. Humphrey [h]	43	General Counsel and Senior Vice President - Human Resources - Great Plains Energy and KCP&L	2010
Darrin R. Ives [i]	44	Vice President - Regulatory Affairs - KCP&L	2013
Lori A. Wright [j]	51	Vice President - Business Planning and Controller - 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). He was Chief Financial Officer of KCP&L (2005-2008) and GMO (2008).

(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. Shay was appointed Senior Vice President - Finance and Strategic Development and Chief Financial Officer of Great Plains Energy, KCP&L and GMO in 2010. He was Chief Financial Officer, with responsibilities for finance, accounting and information technology, at Northern Power Systems, Inc., a wind turbine manufacturing business (2009-2010); Managing Director, with responsibilities for business development, transaction execution and advisory work, at Frontier Investment Banc Corporation (2007-2008); and Chief Financial Officer, with responsibilities for finance, accounting, human resources, information technology and procurement, at Machine Laboratory LLC, a manufacturer of machined parts for the automotive industry (2006-2007).

(d) Mr. Bryant was appointed Vice President - Investor Relations and Strategic Planning and Treasurer of Great Plains Energy, KCP&L and GMO in 2013. He previously 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.

(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 (2007-2008). Prior to that, he was the president of the Missouri Energy Development Association (2005-2007).

(f) Mr. Deggendorf was appointed Senior Vice President - Corporate Services 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).

(g) Ms. Fairchild was appointed Vice President, Corporate Secretary and Chief Compliance Officer 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. Prior to that, she was an associate at Hagen and Partners (2005-2007), a public relations firm.

(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). Prior to that, she was a shareholder of the law firm of Shughart Thomson & Kilroy (1996-2006).

(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 - Business Planning and Controller of Great Plains Energy, KCP&L and GMO in 2012. She previously served as Vice President and Controller of Great Plains Energy, KCP&L and GMO (2009-2012). She was Controller of Great Plains Energy and KCP&L (2002-2008) and GMO (2008).

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.

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, SPP and NERC. 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 investment prudently incurred to provide utility service plus a reasonable return on such investment. 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. 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 for environmental projects, as well as other projects, 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 and fuel, purchased power and certain transmission costs 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 Kansas. There is the potential for future federal or state mandatory energy efficiency requirements. KCP&L has implemented certain energy efficiency programs, and currently the recovery of these program expenses are on a deferred basis with no recovery mechanism for associated lost revenues.

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 investment 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 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, creation of a public nuisance or other matters, and seeking injunctions or monetary 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.

As discussed above, 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 15 to the consolidated financial statements for additional information regarding certain significant environmental matters.

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, while the United States is not a current party to the international Kyoto Protocol, it has agreed to undertake certain voluntary actions under the non-binding Copenhagen Accord and pursuant to subsequent international discussions relating to climate change, including the establishment of a goal to reduce greenhouse gas emissions. International agreements legally binding on the United States may be reached in the future. Such new laws or regulations could mandate new or increased requirements to control or reduce the emission of greenhouse

gases, such as 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 25 million tons and 18 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. Most of the Companies' generating facilities are affected by these existing rules and would be affected by the proposed rules. 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, 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, NO_X, 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 have been stayed pending judicial review or are otherwise subject to revision. The Companies' current estimate of capital expenditures (exclusive of Allowance for Funds Used During Construction (AFUDC) and property taxes) to comply with current final environmental regulations where the timing is certain is approximately $700 million. This estimate reflects costs to install environmental equipment at KCP&L's La Cygne Nos. 1 and 2 by June 2015 to comply with the best available retrofit technology (BART) rule and environmental upgrades at other coal-fired generating units through 2016 to comply with the Mercury and Air Toxics Standards (MATS) rule. The Companies estimate that other capital projects at coal-fired generating units for compliance with the Clean Air Act and Clean Water Act (discussed below) based on proposed regulations or final regulations with implementation plans not yet finalized where the timing is uncertain could be approximately $600 to $800 million, which includes approximately $350 million to $450 million for KCP&L. These other projects are not included in the approximately $700 million estimated cost of compliance discussed above. 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 requires at least 5% of the electricity provided by certain utilities, including KCP&L and GMO, to come from renewable resources, increasing to 10% by 2018 and 15% by 2021. Kansas law requires certain utilities, including KCP&L, to have renewable energy generation capacity equal to at least 10% of their three-year average Kansas peak retail demand, increasing to 15% by 2016 and 20% by 2020. 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 March 2011, the EPA proposed regulations regarding protection of aquatic life from being killed or injured by cooling water intake structures. The EPA agreed to finalize the rule by April 2014. Although the impact on the Companies' operations will not be known until after the rule is finalized, it could have a significant effect on the Companies' results of operations, financial position and cash flows.

KCP&L holds a permit from the Missouri Department of Natural Resources (MDNR) authorizing KCP&L to, among other things, withdraw water from the Missouri River for cooling purposes and return the heated water to the Missouri River at its Hawthorn Station. 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. KCP&L cannot predict the outcome of this matter; however, while less significant outcomes are possible, this matter may require KCP&L to reduce its generation at Hawthorn Station, install cooling towers or both, any of which could have a significant adverse impact on KCP&L's results of operations, financial position and cash flows. The outcome could also affect the terms of water permit renewals at KCP&L's Iatan Station and at GMO's Sibley and Lake Road Stations. Additionally, in April 2013, the EPA proposed to revise the technology-based effluent limitations guidelines and standards regulation to make the existing controls on discharges from steam electric power plants more stringent. The EPA is under a consent decree to take final action on the proposed rule by May 2014. Until a rule is finalized, the financial and operational impacts cannot be determined. 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. The Companies principally use coal in generating electricity and dispose of coal combustion residuals (CCRs) in both on-site facilities and facilities owned by third parties. The EPA has proposed regulations regarding the handling and disposal of CCRs, which include alternative proposals to regulate CCRs as special or hazardous waste or as non-hazardous waste. If enacted, any new laws and regulations, especially if CCRs are classified as hazardous waste, 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 emissions 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 their 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.

Although the United States capital and credit markets have generally stabilized after an extended period of volatility and disruption, there is no assurance that conditions will not deteriorate in the future due to instability in global markets, political uncertainty in the United States 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 $99.9 million of long-term debt of GMO. Great Plains Energy also guarantees GMO's commercial paper program. At December 31, 2013, GMO had $15.0 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 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. While these corporate and regulatory restrictions and financial covenants are not expected to affect the Companies' ability to pay dividends at the current level in the foreseeable future, there is no assurance that adverse financial results would not trigger such restrictions or covenants and reduce or eliminate the Companies' ability to pay dividends.

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, or other factors may adversely affect the Companies' results of operations, financial position and cash flows.

Technological advances 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 could become more cost competitive. If these technologies become cost competitive, 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.

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, 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. An 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 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.

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 construction 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 construction projects pending and may also have significant construction projects in the future. The risks of any construction 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 construction 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 infrastructure. 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 the utilities' generation and 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, potential liability associated with the potential harmful effects on the environment and human health resulting from the operation of a nuclear generating unit and the storage, handling, disposal and potential release (by accident, through third-party actions or otherwise) of radioactive materials. 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 regional power market in which the Companies operate has changing market and transmission structures, which could have an adverse effect on the Companies' results of operations, financial position and cash flows.
In March 2014, the SPP is scheduled to launch its Integrated Marketplace. Similar to other RTO or Independent System Operator (ISO) markets currently operating, this marketplace will determine 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 once the Integrated Marketplace begins operations.

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 have acquired TCRs for the purpose of hedging against transmission congestion charges once the Integrated Marketplace begins operations. 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.

Commodity Price Risks:

Changes in commodity prices could have an adverse effect on the Companies' results of operations, financial position and cash flows.
The Companies engage in the wholesale and retail marketing of electricity and are exposed to risks associated with the price of electricity. To the extent that exposure to the price of electricity is not successfully hedged, the Companies could experience losses associated with the changing market price for electricity.

Increases in fuel, fuel transportation and purchased power prices could have an adverse impact on the Companies' costs.
KCP&L's Kansas retail rates and GMO's retail electric and steam rates contain fuel recovery mechanisms. KCP&L's Missouri retail rates do not contain a similar provision. As a result, the Companies are exposed to varying degrees of risk from changes in the market prices of fuel for generation of electricity and purchased power. Changes in the Companies' fuel mix due to electricity demand, plant availability, transportation issues, fuel prices, fuel availability and other factors can also adversely affect the Companies' fuel and purchased power costs.

The Companies do not hedge their respective entire exposures from fuel and transportation price volatility. Consequently, the Companies' results of operations, financial position and cash flows may be materially impacted by changes in these prices unless and until increased costs are recovered in KCP&L's Missouri retail rates.

Wholesale electricity sales affect revenues, creating earnings volatility.
The levels of the Companies' wholesale sales depend on the wholesale market price, transmission availability and the availability of generation for wholesale sales, among other factors. A substantial portion of wholesale sales are made in the spot market, and thus the Companies have immediate exposure to wholesale price changes. Wholesale power prices can be volatile and generally increase in times of high regional demand and high natural gas prices. Conversely, wholesale power prices generally decrease in times of low regional demand and low natural gas prices. While wholesale sales are reflected in KCP&L's Kansas and GMO's fuel recovery mechanisms, KCP&L's Missouri rates are set on an estimated amount of wholesale sales. KCP&L will not recover any shortfall in non-firm wholesale electric sales margin from the level included in Missouri rates. Declines in wholesale market price, availability of generation, transmission constraints in the wholesale markets, or low wholesale demand could reduce the Companies' wholesale sales and may materially affect the Companies' results of operations, financial position and cash flows.

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 2014 MW Capacity	Primary Fuel
Base Load	Iatan No. 2	Missouri	2010	482 [a]	Coal
	Wolf Creek	Kansas	1985	547 [a]	Nuclear
	Iatan No. 1	Missouri	1980	499 [a]	Coal
	La Cygne Nos. 1 and 2	Kansas	1973, 1977	709 [a]	Coal
	Hawthorn No. 5 [b]	Missouri	1969	564	Coal
	Montrose Nos. 1, 2 and 3	Missouri	1958, 1960, 1964	517	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	227	Natural Gas
	Hawthorn No. 8	Missouri	2000	72	Natural Gas
	Hawthorn No. 7	Missouri	2000	69	Natural Gas
	Northeast Black Start Unit	Missouri	1985	2	Oil
	Northeast Nos. 17 and 18	Missouri	1977	97	Oil
	Northeast Nos. 13 and 14	Missouri	1976	91	Oil
	Northeast Nos. 15 and 16	Missouri	1975	89	Oil
	Northeast Nos. 11 and 12	Missouri	1972	96	Oil
Wind	Spearville 2 Wind Energy Facility [c]	Kansas	2010	3	Wind
	Spearville 1 Wind Energy Facility [d]	Kansas	2006	7	Wind
Total KCP&L				4,459	
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	463	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	317	Natural Gas
	Crossroads Energy Center	Mississippi	2002	307	Natural Gas
	Ralph Green No. 3	Missouri	1981	71	Natural Gas
	Greenwood Nos. 1, 2, 3 and 4	Missouri	1975-1979	248	Natural Gas/Oil
	Lake Road No. 5	Missouri	1974	67	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	19	Oil
Total GMO				2,124	
Total Great Plains Energy				6,583	

[a] Share of a jointly owned unit.
[b] The Hawthorn Generating Station returned to commercial operation in 2001 with a new boiler, air quality control equipment and an uprated turbine following a 1999 explosion.
[c] The 48 MW Spearville 2 Wind Energy Facility's accredited capacity is 3 MW pursuant to SPP reliability standards.
[d] The 100.5 MW Spearville Wind Energy Facility's accredited capacity is 7 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 3,700 circuit miles of transmission lines, 15,600 circuit miles of overhead distribution lines and 6,800 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 South Harper 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 $596.4 million were outstanding at December 31, 2013.

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 $9.0 million were outstanding at December 31, 2013.

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, 15 and 16 to the consolidated financial statements. Such information is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

GREAT PLAINS ENERGY

Great Plains Energy's common stock is listed on the New York Stock Exchange under the symbol "GXP". At February 25, 2014, Great Plains Energy's common stock was held by 18,170 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		
	2013		2012				
Quarter	High	Low	High	Low	2014	2013	2012
First	$ 23.19	$ 20.41	$ 21.60	$ 19.60	$ 0.23 [b]	$ 0.2175	$ 0.2125
Second	24.41	21.94	21.41	19.54		0.2175	0.2125
Third	24.60	21.49	22.48	21.26		0.2175	0.2125
Fourth	24.76	21.86	22.81	19.80		0.23	0.2175

[a] Based on closing stock prices.
[b] Declared February 11, 2014, and payable March 20, 2014, to shareholders of record as of February 27, 2014.

Dividend Restrictions

For information regarding dividend restrictions, see Note 13 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, 2013.

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 13 to the consolidated financial statements.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31	2013	2012	2011	2010	2009
Great Plains Energy	(dollars in millions except per share amounts)				
Operating revenues	$ 2,446	$ 2,310	$ 2,318	$ 2,256	$ 1,965
Income from continuing operations [(a)]	$ 250	$ 200	$ 174	$ 212	$ 152
Net income attributable to Great Plains Energy	$ 250	$ 200	$ 174	$ 212	$ 150
Basic earnings per common share from continuing operations	$ 1.62	$ 1.36	$ 1.27	$ 1.55	$ 1.16
Basic earnings per common share	$ 1.62	$ 1.36	$ 1.27	$ 1.55	$ 1.15
Diluted earnings per common share from continuing operations	$ 1.62	$ 1.35	$ 1.25	$ 1.53	$ 1.15
Diluted earnings per common share	$ 1.62	$ 1.35	$ 1.25	$ 1.53	$ 1.14
Total assets at year end	$ 9,795	$ 9,647	$ 9,118	$ 8,818	$ 8,483
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities)	$ 3,517	$ 3,020	$ 3,544	$ 3,428	$ 3,214
Cash dividends per common share	$ 0.8825	$ 0.855	$ 0.835	$ 0.83	$ 0.83
SEC ratio of earnings to fixed charges	2.75	2.31	2.03	2.28	1.81
KCP&L					
Operating revenues	$ 1,671	$ 1,580	$ 1,558	$ 1,517	$ 1,318
Net income	$ 169	$ 142	$ 136	$ 163	$ 129
Total assets at year end	$ 6,839	$ 6,704	$ 6,292	$ 6,026	$ 5,702
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities)	$ 2,312	$ 1,902	$ 1,915	$ 1,780	$ 1,780
SEC ratio of earnings to fixed charges	2.76	2.58	2.52	2.86	2.44

[(a)] This amount is before loss from discontinued operations, net of income taxes, of $1.5 million in 2009.

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 direct subsidiaries with operations or active subsidiaries are KCP&L, GMO and GPETHC.

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 6,600 MWs of generating capacity and engages in the generation, transmission, distribution and sale of electricity to approximately 830,800 customers in the states of Missouri and Kansas. Electric utility's retail electricity rates are comparable to the national average of investor-owned utilities.

2013 Earnings Overview
Great Plains Energy's 2013 earnings available for common shareholders increased to $248.6 million or $1.62 per share from $198.3 million or $1.35 per share in 2012 driven by:

- an $86.7 million increase in gross margin driven by new retail rates, an increase in weather-normalized retail demand and the impact from an unplanned outage at Wolf Creek in the first quarter of 2012, partially offset by unfavorable weather and increased purchased power and transmission expense;
- a $2.4 million decrease in Wolf Creek operating and maintenance expenses primarily due to an unplanned outage in the first quarter of 2012, mostly offset by higher operating and maintenance expenses in 2013;
- a $22.0 million increase from certain regulatory items included in operating and maintenance expenses including increased pension expense corresponding to the resetting of pension expense trackers with the effective date of new retail rates, costs for energy efficiency and demand side management programs under the Missouri Energy Efficiency Investment Act (MEEIA), and solar rebates provided to customers, all of which are included in retail rates;
- a $15.1 million increase in general taxes driven by increased property taxes;
- a $22.4 million decrease in interest expense primarily due to the repayment of GMO's $500.0 million 11.875% Senior Notes at maturity in July 2012, a lower interest rate on the refinanced long-term debt that was underlying Great Plains Energy's $287.5 million Equity Units, the repayment of Great Plains Energy's $250.0 million 2.75% Senior Notes at maturity in August 2013 and an increase in the debt component of AFUDC at KCP&L. These decreases were partially offset by increased interest expense due to KCP&L's issuance of $300.0 million 3.15% Senior Notes in March 2013 and GMO's issuance of $350.0 million of senior notes in August 2013; and
- a $24.6 million increase in income tax expense driven primarily by increased pre-tax income and $4.5 million of income tax benefits related to the release of uncertain tax positions in 2012.

In addition, a higher number of shares outstanding due to the issuance of 17.1 million shares in connection with the June 2012 settlement of the purchase contracts underlying the Equity Units diluted earnings per share by $0.06.

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.

Wolf Creek Refueling Outage
Wolf Creek's latest refueling outage began on February 4, 2013, and the unit returned to service on April 15, 2013. A mid-cycle maintenance outage is planned for the spring of 2014 with the next refueling outage planned to begin in the first quarter of 2015.

Transmission Investment Opportunities
GPETHC, a wholly owned subsidiary of Great Plains Energy, owns 13.5% of Transource with AEPTHC, a subsidiary of American Electric Power Company, Inc., owning the remaining 86.5%. Transource is focused on the development of competitive electric transmission projects.

In December 2013, FERC accepted the SPP's approval of the novation of KCP&L's and GMO's SPP-approved regional transmission projects to Transource Missouri, LLC (Transource Missouri), a wholly owned subsidiary of Transource. The projects consist of an approximately 30-mile, 345kV transmission line from KCP&L's and GMO's Iatan generating station to KCP&L's Nashua substation with estimated construction costs of $65 million and an

expected 2015 in-service date (Iatan-Nashua line) and the Missouri portion of an approximately 180-mile, 345kV transmission line from Sibley, Missouri to Nebraska City, Nebraska with estimated construction costs of $330 million for Transource Missouri's portion of the line and an expected 2017 in-service date (Sibley-Nebraska City line). In January 2014, KCP&L and GMO sold the related assets of these projects, at cost, to Transource Missouri. See Note 12 to the consolidated financial statements for information regarding the asset sale.

ENVIRONMENTAL MATTERS

See Note 15 to the consolidated financial statements for information regarding environmental matters.

RELATED PARTY TRANSACTIONS

See Note 18 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 2013 Pension Expense
		(millions)	
Discount rate	0.5% increase	$ (66.0)	$ (5.1)
Rate of return on plan assets	0.5% increase	—	(3.5)
Discount rate	0.5% decrease	70.8	5.2
Rate of return on plan assets	0.5% decrease	—	3.5

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 2013, Great Plains Energy's pension expense was $102.5 million under GAAP and $85.7 million for ratemaking. The impact on 2013 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, 2013. Fair value of the reporting unit 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, 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. This process requires management to make assessments regarding the timing and probability of the ultimate tax impact. 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.

Additionally, the Company establishes reserves for uncertain tax positions based upon management's judgment regarding potential future challenges to those positions. The accounting estimates related to the liability for uncertain tax positions require management to make judgments regarding the sustainability of each uncertain tax

position based on its technical merits. If it is determined that it is more likely than not a tax position will be sustained based on its technical merits, the impact of the position is recorded in the Company's consolidated financial statements at the largest amount that is greater than fifty percent likely of being realized upon ultimate settlement. These estimates are updated at each reporting date based on the facts, circumstances and information available. Management is also required to assess at each reporting date whether it is reasonably possible that any significant increases or decreases to the unrecognized tax benefits will occur during the next twelve months. See Note 22 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.

	2013	2012	2011
		(millions)	
Operating revenues	$ 2,446.3	$ 2,309.9	$ 2,318.0
Fuel	(539.5)	(539.5)	(483.8)
Purchased power	(125.9)	(94.0)	(203.4)
Transmission	(53.2)	(35.4)	(30.2)
Gross margin [a]	1,727.7	1,641.0	1,600.6
Other operating expenses	(868.8)	(834.1)	(835.0)
Voluntary separation program	—	4.3	(12.7)
Depreciation and amortization	(289.7)	(272.3)	(273.1)
Operating income	569.2	538.9	479.8
Non-operating income and expenses	8.8	(13.2)	(2.3)
Interest charges	(198.4)	(220.8)	(218.4)
Income tax expense	(129.2)	(104.6)	(84.8)
Loss from equity investments	(0.2)	(0.4)	(0.1)
Net income	250.2	199.9	174.2
Less: Net loss attributable to noncontrolling interest	—	—	0.2
Net income attributable to Great Plains Energy	250.2	199.9	174.4
Preferred dividends	(1.6)	(1.6)	(1.6)
Earnings available for common shareholders	$ 248.6	$ 198.3	$ 172.8

[a] Gross margin is a non-GAAP financial measure. See explanation of gross margin below.

2013 Compared to 2012

Great Plains Energy's 2013 earnings available for common shareholders increased to $248.6 million or $1.62 per share from $198.3 million or $1.35 per share in 2012.

Electric utility's net income increased $40.5 million in 2013 compared to 2012 driven by:

- an $86.7 million increase in gross margin driven by:
  - an estimated $111 million increase primarily from new retail rates in Kansas effective January 1, 2013, and Missouri effective January 26, 2013;
  - an estimated $42 million increase driven by an increase in weather-normalized retail demand;
  - an estimated $4 million increase from the impact of an unplanned outage at Wolf Creek in the first quarter of 2012;
  - an estimated $47 million decrease due to unfavorable weather driven by a 27% decrease in cooling degree days partially offset by the impact of favorable weather during the first and fourth quarters of 2013; and
  - an estimated $23 million decrease primarily due to increased purchased power and transmission expense;

- a $2.4 million decrease in Wolf Creek operating and maintenance expenses primarily due to an unplanned outage in the first quarter of 2012, mostly offset by higher operating and maintenance expenses in 2013;
- a $22.0 million increase from certain regulatory items included in operating and maintenance expenses including increased pension expense corresponding to the resetting of pension expense trackers with the effective date of new retail rates, costs for energy efficiency and demand side management programs under MEEIA, and solar rebates provided to customers, all of which are included in retail rates;
- a $15.3 million increase in general taxes driven by increased property taxes;
- a $6.8 million decrease in interest expense primarily due to:
    - a $13.4 million decrease from the repayment of GMO's $500.0 million 11.875% Senior Notes at maturity in July 2012;
    - a $6.5 million increase in the debt component of AFUDC resulting from a higher average construction work in progress balance due to environmental upgrades at KCP&L's La Cygne Station;
    - a $7.5 million increase due to KCP&L's issuance of $300.0 million 3.15% Senior Notes in March 2013;
    - a $5.4 million increase resulting from GMO's issuance of $350.0 million of senior notes in August 2013; and
    - a $3.9 million increase relating to intercompany loans from Great Plains Energy to GMO; and
- a $13.4 million increase in income tax expense driven primarily by increased pre-tax income.

Great Plains Energy's corporate and other activities loss decreased $9.8 million in 2013 compared to 2012 driven by:

- an $8.1 million decrease in after-tax interest expense as a result of a lower interest rate on the refinanced long-term debt that was underlying Great Plains Energy's $287.5 million Equity Units and the repayment of Great Plains Energy's $250.0 million 2.75% Senior Notes at maturity in August 2013;
- a $2.3 million increase in after-tax intercompany interest income relating to intercompany loans from Great Plains Energy to GMO; and
- 2012 included:
    - a $1.8 million after-tax loss on the sale of real estate property; and
    - $4.5 million of income tax benefits from the release of uncertain tax positions related to former GMO non-regulated operations.

2012 Compared to 2011

Great Plains Energy's 2012 earnings available for common shareholders increased to $198.3 million or $1.35 per share from $172.8 million or $1.25 per share in 2011.

Electric utility's net income increased $16.7 million in 2012 compared to 2011 driven by:

- new retail rates in Missouri effective May 4, 2011, for KCP&L and June 25, 2011, for GMO;
- favorable weather with a 15% increase in cooling degree days partially offset by the impact of unfavorable weather during the first quarter of 2012; and
- 2011 included:
    - the impact from flooding along the Missouri River, which decreased gross margin by an estimated $16 million due to coal conservation and increased other operating expenses $3.3 million;
    - an estimated $11 million decrease in gross margin from an extended refueling outage at Wolf Creek;

- $12.7 million of expense relating to a voluntary separation program; and
- a $2.3 million loss relating to the impact of disallowed construction costs for the Iatan No. 1 environmental project and Iatan No. 2 and $3.9 million of expenses related to other accounting effects of the KCP&L and GMO 2011 MPSC rate orders.

These increases were partially offset by:

- a decrease in weather-normalized retail demand;
- decreased gross margin from lower KCP&L Missouri wholesale sales margin along with increased fuel and transmission expense, partially offset by favorable purchased power expense at KCP&L in Missouri, where there is no fuel recovery mechanism;
- an estimated $17 million impact at Wolf Creek due to an unplanned outage in the first quarter of 2012, increased amortization from the 2011 extended refueling outage and increased other operating expenses; and
- a $20.4 million increase in interest expense primarily due to the deferral to a regulatory asset of $22.1 million of Iatan Nos. 1, 2 and common facilities construction accounting carrying costs during 2011.

Great Plains Energy's corporate and other activities loss decreased $8.8 million in 2012 compared to 2011 primarily due to a $4.3 million decrease in after-tax interest expense as a result of a lower interest rate on the refinanced long-term debt that was underlying Great Plains Energy's $287.5 million Equity Units; a $1.6 million decrease in after-tax interest expense related to the release of uncertain tax positions; and expenses of $2.3 million included in 2011 related to the resolution of certain general tax related matters. These decreases were partially offset by a $1.8 million after-tax loss on the sale of real estate property in 2012 and a $2.2 million tax benefit from the reversal of tax valuation allowances in 2011.

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 transmission, offset by wholesale sales margin, are subject to recovery through cost adjustment mechanisms, except for KCP&L's Missouri retail operations. 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.

	2013	2012	2011
		(millions)	
Operating revenues	$ 2,446.3	$ 2,309.9	$ 2,318.0
Fuel	(539.5)	(539.5)	(483.8)
Purchased power	(125.9)	(94.0)	(203.4)
Transmission	(53.2)	(35.4)	(30.2)
Gross margin [a]	1,727.7	1,641.0	1,600.6
Other operating expenses	(865.6)	(825.9)	(828.7)
Voluntary separation program	—	4.3	(12.7)
Depreciation and amortization	(289.7)	(272.3)	(273.1)
Operating income	572.4	547.1	486.1
Non-operating income and expenses	10.6	(11.2)	—
Interest charges	(190.5)	(197.3)	(176.9)
Income tax expense	(135.4)	(122.0)	(109.3)
Net income	$ 257.1	$ 216.6	$ 199.9

[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]	2013	% Change	2012	% Change	2011
Retail revenues			(millions)		
Residential	$ 1,008.4	4	$ 965.5	1	$ 955.8
Commercial	966.7	7	907.6	3	878.8
Industrial	213.0	8	197.8	1	196.7
Other retail revenues	20.5	3	19.9	3	19.5
Kansas property tax surcharge	(1.3)	N/M	4.8	32	3.7
Provision for rate refund	—	N/M	0.1	N/M	(2.9)
Fuel recovery mechanism	21.9	23	17.8	(65)	50.6
Total retail	2,229.2	5	2,113.5	1	2,102.2
Wholesale revenues	168.8	10	152.9	(11)	172.4
Other revenues	48.3	11	43.5	—	43.4
Operating revenues	2,446.3	6	2,309.9	—	2,318.0
Fuel	(539.5)	—	(539.5)	12	(483.8)
Purchased power	(125.9)	34	(94.0)	(54)	(203.4)
Transmission	(53.2)	50	(35.4)	17	(30.2)
Gross margin	$ 1,727.7	5	$ 1,641.0	3	$ 1,600.6

[a] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

MWh Sales	2013	% Change	2012	% Change	2011
Retail MWh sales			(thousands)		
Residential	8,999	1	8,930	(4)	9,285
Commercial	10,782	—	10,767	—	10,782
Industrial	3,132	(1)	3,174	(1)	3,218
Other retail MWh sales	118	(2)	121	—	119
Total retail	23,031	—	22,992	(2)	23,404
Wholesale MWh sales	6,283	—	6,283	14	5,491
Total MWh sales	29,314	—	29,275	1	28,895

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, purchased power and transmission availability, fuel costs, and requirements of other electric systems. Electric utility's revenues contain certain fuel 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, transmission costs 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.
- GMO's electric 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 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.

KCP&L's Missouri retail rates do not contain a fuel recovery mechanism, meaning that changes in fuel, purchased power and transmission costs will not be reflected in rates until new rates are authorized by the MPSC, creating a regulatory lag between the time costs change and when they are reflected in rates. In the current rising cost environment, regulatory lag can be expected to have an adverse impact, which could be material, on Great Plains Energy's results of operations. KCP&L's retail rates in Missouri reflect a set level of non-firm wholesale electric sales margin. KCP&L does not recover any shortfall in non-firm wholesale electric sales margin from the level included in Missouri retail rates.

Electric utility's gross margin increased $86.7 million in 2013 compared to 2012 driven by:

- an estimated $111 million increase primarily from new retail rates in Kansas effective January 1, 2013, and Missouri effective January 26, 2013;
- an estimated $42 million increase driven by an increase in weather-normalized retail demand;
- an estimated $4 million increase from the impact of an unplanned outage at Wolf Creek in the first quarter of 2012;

- an estimated $47 million decrease due to unfavorable weather driven by a 27% decrease in cooling degree days partially offset by the impact of favorable weather during the first and fourth quarters of 2013; and
- an estimated $23 million decrease primarily due to increased purchased power and transmission expense. Purchased power expense increased primarily due to increased MWh purchases under new wind generation power purchase agreements, which are included in new retail rates. Transmission expense increased primarily due to SPP base plan funding transmission charges, of which a portion is included in new retail rates.

Electric utility's gross margin increased $40.4 million in 2012 compared to 2011 primarily due to:

- new retail rates in Missouri effective May 4, 2011, for KCP&L and June 25, 2011, for GMO;
- favorable weather, with a 15% increase in cooling degree days partially offset by the impact of unfavorable weather during the first quarter of 2012; and
- 2011 included an estimated $11 million impact from an extended refueling outage at Wolf Creek and the impact from flooding along the Missouri River, which decreased gross margin by an estimated $16 million due to coal conservation.

These increases were partially offset by:

- a decrease in weather-normalized retail demand;
- decreased gross margin from lower KCP&L Missouri wholesale sales margin along with increased fuel and transmission expense, partially offset by favorable purchased power expense at KCP&L in Missouri, where there is no fuel recovery mechanism; and
- an estimated $4 million impact from an unplanned outage at Wolf Creek in the first quarter of 2012.

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.

	2013	% Change	2012	% Change	2011
CDD	1,345	(27)	1,839	15	1,598
HDD	5,561	38	4,028	(23)	5,220

Electric Utility Other Operating Expenses ***(including utility operating and maintenance expenses, general taxes and other)***

Electric utility's other operating expenses increased $39.7 million in 2013 compared to 2012 primarily due to:

- a $7.6 million increase in pension expense corresponding to the resetting of pension expense trackers with the effective date of new retail rates;
- $8.3 million relating to costs for energy efficiency and demand side management programs under MEEIA;
- a $6.1 million increase relating to solar rebates provided to customers due to the deferral to a regulatory asset for recovery in future rates of $3.0 million in the first quarter of 2012 and $3.1 million of regulatory asset amortization in 2013; and
- a $15.3 million increase in general taxes driven by increased property taxes.

These increases were partially offset by a $2.4 million decrease in Wolf Creek operating and maintenance expenses primarily due to an unplanned outage in the first quarter of 2012, mainly offset by higher operating and maintenance expenses in 2013.

Electric utility's other operating expenses decreased $2.8 million in 2012 compared to 2011 primarily due to:

- a $14.1 million decrease in plant operating and maintenance expenses primarily due to planned plant outages, other than at Wolf Creek, with longer durations in 2011 than in 2012;
- 2011 included expense of $2.7 million relating to solar rebates provided to customers and in 2012, $3.0 million was deferred to a regulatory asset for recovery in future rates; and
- 2011 included $3.3 million of expenses related to the impact of flooding, a $2.3 million loss related to the impact of disallowed construction costs for the Iatan No. 1 environmental project and Iatan No. 2 and $3.9 million of expenses related to other accounting effects of the KCP&L and GMO 2011 MPSC rate orders.

These decreases were mostly offset by a $12.8 million increase in operating and maintenance expenses at Wolf Creek primarily due to an unplanned outage in the first quarter of 2012, along with increased amortization from the 2011 extended refueling outage and increased other operating expenses, and an $11.3 million increase in general taxes driven by increased property taxes.

Electric Utility Voluntary Separation Program

In 2011, Great Plains Energy executed an organizational realignment and voluntary separation program to assist in the management of overall costs within the level reflected in the Company's retail electric rates and to enhance organizational efficiency. Electric utility recorded expense of $12.7 million in 2011 related to this voluntary separation program reflecting severance and related payroll taxes provided to employees who elected to voluntarily separate from the Company. In 2012, KCP&L deferred $4.3 million of expense related to the voluntary separation program to a regulatory asset for recovery in rates beginning January 1, 2013, pursuant to KCP&L's December 2012 KCC rate order.

Electric Utility Depreciation and Amortization

Electric utility's depreciation and amortization costs increased $17.4 million in 2013 compared to 2012 driven by higher depreciation rates for KCP&L as well as increased depreciation expense for other capital additions.

Electric utility's depreciation and amortization costs decreased $0.8 million in 2012 compared to 2011 primarily due to $14.4 million of lower regulatory amortization for KCP&L in Missouri, which was in effect during KCP&L's Comprehensive Energy Program but concluded following the May 2011 effective date of new retail rates for KCP&L in Missouri. This decrease was mostly offset by a $6.4 million increase in depreciation for Iatan No. 2 (Missouri jurisdiction only) and increased depreciation expense for other capital additions.

Electric Utility Non-Operating Income and Expenses

Electric utility's non-operating income and expenses increased $21.8 million in 2013 compared to 2012 primarily due to a $12.8 million increase in the equity component of AFUDC at KCP&L and $4.2 million of expense recorded in 2012 related to accounting effects of the GMO January 2013 rate order as well as other increased expenses from non-regulated activities.

Electric utility's non-operating income and expenses decreased $11.2 million in 2012 compared to 2011 driven by $4.2 million of expense recorded in 2012 related to accounting effects of the GMO January 2013 rate order as well as other increased expenses from non-regulated activities.

Electric Utility Interest Charges

Electric utility's interest charges decreased $6.8 million in 2013 compared to 2012 primarily due to a $13.4 million decrease from the repayment of GMO's $500.0 million 11.875% Senior Notes at maturity in July 2012 and a $6.5 million increase in the debt component of AFUDC resulting from a higher average construction work in progress balance due to environmental upgrades at KCP&L's La Cygne Station.

These decreases were partially offset by:

- $7.5 million increase due to KCP&L's issuance of $300.0 million 3.15% Senior Notes in March 2013;
- a $5.4 million increase resulting from GMO's issuance of $350.0 million of senior notes in August 2013; and
- a $3.9 million increase relating to intercompany loans from Great Plains Energy to GMO.

Electric utility's interest charges increased $20.4 million in 2012 compared to 2011 primarily due to the deferral to a regulatory asset of $22.1 million of construction accounting carrying costs for Iatan Nos. 1, 2 and common facilities in 2011.

Electric Utility Income Tax Expense
Electric utility's income tax expense increased $13.4 million in 2013 compared to 2012 primarily due to increased pre-tax income. Electric utility's income tax expense increased $12.7 million in 2012 compared to 2011 primarily due to increased pre-tax income.

GREAT PLAINS ENERGY SIGNIFICANT BALANCE SHEET CHANGES
(December 31, 2013 compared to December 31, 2012)

- Great Plains Energy's fuel inventories decreased $18.7 million primarily due to a decrease in coal inventory driven by longer cycle times for coal deliveries.
- Assets held for sale increased $36.2 million to reflect KCP&L's and GMO's SPP-approved regional transmission projects as assets held for sale. The assets were sold to Transource Missouri in January 2014.
- Great Plains Energy's construction work in progress increased $152.2 million primarily due to environmental upgrades at KCP&L's La Cygne Station and pipe replacement for the essential service water system at the Wolf Creek nuclear unit, partially offset by projects placed in service for normal plant activity.
- Great Plains Energy's regulatory assets decreased $271.2 million primarily due to an increase in actual return on pension and post-retirement plan assets as the result of favorable market conditions, an increase in actuarial gain driven by an increase in the discount rate assumption used to determine benefit obligations and the difference between pension and post-retirement costs recorded under GAAP and costs for ratemaking. This difference is due to timing and will be eliminated over the life of the benefit plans.
- Great Plains Energy's commercial paper decreased $421.9 million primarily due to repayment with proceeds from KCP&L's issuance of $300.0 million of 3.15% Senior Notes, the remarketing of $112.8 million of Environmental Improvement Revenue Refunding (EIRR) bonds previously held by KCP&L and a portion of the proceeds from GMO's issuance of $350.0 million of senior notes partially offset by borrowings for interest and dividend payments.
- Great Plains Energy's current maturities of long-term debt decreased $262.0 million primarily due to the repayment of Great Plains Energy's $250.0 million 2.75% Senior Notes at maturity in August 2013.
- Great Plains Energy's deferred income taxes - deferred credits and other liabilities increased $132.4 million primarily due to an increase in temporary differences mostly as a result of bonus depreciation.
- Great Plains Energy's pension and post-retirement liability - deferred credits and other liabilities decreased $197.0 million primarily due to an increase in actual return on plan assets as the result of favorable market conditions and an increase in actuarial gain driven by an increase in the discount rate assumption used to determine benefit obligations.
- Great Plains Energy's long-term debt increased $758.9 million primarily due to the issuance, at a discount, of KCP&L's $300.0 million of 3.15% Senior Notes in March 2013, the remarketing in April 2013 of $112.8 million of EIRR bonds previously held by KCP&L and GMO's issuance of $350.0 million of senior notes in August 2013.

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 are 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, 2013, consisted of $10.6 million of cash and cash equivalents on hand and $1.1 billion of unused bank lines of credit. The unused lines consisted of $191.0 million from Great Plains Energy's revolving credit facility, $503.0 million from KCP&L's credit facilities and $418.6 million from GMO's credit facilities. See Note 10 to the consolidated financial statements for more information regarding the revolving credit facilities. 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, and from time to time 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 $113.0 million increase in cash flows from operating activities for Great Plains Energy in 2013 compared to 2012 is primarily due to a $50.3 million increase in net income along with other changes in working capital that are detailed in Note 2 to the consolidated financial statements. The individual components of working capital vary with normal business cycles and operations.

The $220.8 million increase in cash flows from operating activities for Great Plains Energy in 2012 compared to 2011 is primarily due to an increase in net income, a decrease in pension and post-retirement benefit funding as a result of revised funding requirements, a decrease in deferred refueling outage costs and the payment in 2011 of $26.1 million for the settlement of forward starting swaps upon the issuance of $350.0 million of 4.85% Senior Notes in May 2011.

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 increased $58.8 million in 2013 compared to 2012 primarily due to an increase in cash utility capital expenditures at the Wolf Creek nuclear unit for a back-up diesel generator and pipe replacement for the essential service water system and construction of the SPP-approved regional transmission line from the Iatan generating station to KCP&L's Nashua substation.

Great Plains Energy's utility capital expenditures increased $153.6 million in 2012 compared to 2011 due to an increase in cash utility capital expenditures primarily related to environmental upgrades at KCP&L's La Cygne Station, in addition to normal plant activity.

Cash Flows from Financing Activities

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.

In June 2012, Great Plains Energy settled the obligations under the purchase contracts underlying its 5.7 million outstanding Equity Units by issuing approximately 17.1 million shares of its common stock in exchange for $287.4 million in cash proceeds which Great Plains Energy used to make an intercompany loan to GMO. GMO used the proceeds from the intercompany loan along with increased short-term borrowings to repay its $500 million 11.875% Senior Notes at maturity in July 2012. Great Plains Energy's cash flows from financing activities in 2012 also reflect repayment of KCP&L's $12.4 million of 4.00% EIRR bonds at maturity in January 2012.

Great Plains Energy's cash flows from financing activities in 2011 reflect the issuance, at a discount, of $350.0 million of 4.85% Senior Notes that mature in 2021. Great Plains Energy used the proceeds to make a ten-year intercompany loan to GMO with GMO using the proceeds to repay $137.3 million of 7.95% Senior Notes and $197.0 million of 7.75% Senior Notes at maturity. KCP&L purchased in lieu of redemption its $63.3 million EIRR Series 2007A-1, $10.0 million EIRR Series 2007A-2 and $39.5 million EIRR Series 1993B bonds. Also reflected is KCP&L's issuance, at a discount, of $400.0 million of 5.30% Senior Notes that mature in 2041. KCP&L used the proceeds to repay short-term borrowings and its $150.0 million of 6.50% Senior Notes at maturity.

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 26, 2014, 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	Positive
Corporate Credit Rating	-	BBB
Preferred Stock	Ba1	BB+
Senior Unsecured Debt	Baa2	BBB-
KCP&L		
Outlook	Stable	Positive
Senior Secured Debt	A2	A-
Senior Unsecured Debt	Baa1	BBB
Commercial Paper	P-2	A-2
GMO		
Outlook	Stable	Positive
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 February 2012, the MPSC authorized KCP&L to issue up to $300.0 million of long-term debt and to enter into interest rate hedging instruments in connection with such debt through December 31, 2013. At December 31, 2013, KCP&L had utilized all of this authorization. KCP&L expects to file a request with the MPSC for authorization to issue long-term debt through December 2015 that would replace the authorization which expired on December 31, 2013.

In October 2012, FERC authorized KCP&L to have outstanding at any time up to a total of $1.0 billion in short-term debt instruments through December 2014, conditioned on KCP&L's borrowing costs not exceeding the greater of: (i) 2.25% over LIBOR; (ii) the greater of 1.25% over the prime rate, 1.75% over the federal funds rate, and 2.25% over LIBOR; or (iii) 2.25% over the A2/P-2 nonfinancial commercial paper rate most recently published by the Federal Reserve at the time of the borrowing. The authorization is subject to four restrictions: (i) proceeds of debt backed by utility assets must be used for utility purposes; (ii) if any utility assets that secure authorized debt are divested or spun off, the debt must follow the assets and also be divested or spun off; (iii) if any proceeds of the authorized debt are used for non-utility purposes, the debt must follow the non-utility assets (specifically, if the non-utility assets are divested or spun off, then a proportionate share of the debt must follow the divested or spun off non-utility assets); and (iv) if utility assets financed by the authorized short-term debt are divested or spun off to another entity, a proportionate share of the debt must also be divested or spun off. At December 31, 2013, there was $906.8 million available under this authorization.

In January 2012, FERC authorized GMO to have outstanding at any time up to a total of $750.0 million in short-term debt instruments through March 2014, conditioned on GMO's borrowing costs not exceeding the greater of 2.25% over LIBOR or 1.75% over the prime rate or federal funds rate, as applicable, and subject to the same four restrictions as the KCP&L FERC short-term authorization discussed in the preceding paragraph. At December 31, 2013, there was $735.0 million available under this authorization. In January 2014, FERC authorized GMO to have outstanding at any time up to $750.0 million in short-term debt instruments effective March 2014 through March 2016, subject to the same terms as the previous authorization which expires in March 2014.

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, 2013, KCP&L had an outstanding payable to GMO and GMO had an outstanding payable to Great Plains Energy under the money pool of $0.2 million and $9.4 million, respectively.

Significant Financing Activities

Great Plains Energy

Great Plains Energy has an effective shelf registration statement for the sale of unspecified amounts of securities with the SEC that became effective in March 2012.

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.

In June 2012, Great Plains Energy settled the obligations under the purchase contracts underlying its 5.7 million outstanding Equity Units by issuing approximately 17.1 million shares of its common stock in exchange for $287.4 million. The $287.4 million had been raised through the remarketing of subordinated notes that were originally issued as components of the Equity Units as senior notes at a new interest rate.

In May 2011, Great Plains Energy issued $350.0 million of 4.85% unsecured Senior Notes, maturing in 2021. Great Plains Energy settled six FSS simultaneously with the issuance of the debt and paid $26.1 million in cash for the settlement.

KCP&L

KCP&L has an effective shelf registration statement providing for the sale of unspecified amounts of investment grade notes and general mortgage bonds with the SEC that became effective in March 2012.

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;
- 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.

In September 2011, KCP&L issued $400.0 million of 5.30% unsecured Senior Notes, maturing in 2041.

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 $669.0 million, $610.2 million and $456.6 million in 2013, 2012 and 2011, respectively. 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.

	2014	2015	2016	2017	2018
		(millions)			
Generating facilities	$ 232.7	$ 220.7	$ 211.2	$ 201.8	$ 224.4
Distribution and transmission facilities	202.0	201.6	200.2	199.9	214.1
General facilities	100.6	78.5	60.3	58.3	22.7
Nuclear fuel	47.4	21.9	21.9	42.1	27.2
Environmental	150.7	147.8	101.5	100.4	99.9
Total utility capital expenditures	$ 733.4	$ 670.5	$ 595.1	$ 602.5	$ 588.3

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 the Employee Retirement Income Security Act of 1974, as amended (ERISA).

In 2013 and 2012, the Company contributed $57.4 million and $60.4 million to the pension plans, respectively, and in 2014 the Company expects to contribute $62.8 million to the plans 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 2014 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 $11.3 million under the provisions of these plans in 2014, 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	2014	2015	2016	2017	2018	After 2018	Total
Long-term debt				(millions)			
Principal	$ 1.1	$ 15.1	$ 1.1	$ 382.1	$ 351.1	$ 2,765.5	$ 3,516.0
Interest	180.5	180.1	179.7	172.3	146.5	1,254.6	2,113.7
Lease commitments							
Operating leases	15.3	13.6	10.0	9.7	9.7	138.6	196.9
Capital leases	0.4	0.4	0.4	0.4	0.4	4.4	6.4
Pension and other post-retirement plans	74.1	74.1	74.1	74.1	74.1	N/A	370.5
Purchase commitments							
Fuel	381.8	195.0	143.8	142.8	117.2	90.2	1,070.8
Power	46.4	46.4	46.4	44.8	47.3	604.1	835.4
Capacity	3.3	3.0	1.2	—	—	—	7.5
La Cygne environmental project	205.5	7.3	—	—	—	—	212.8
Non-regulated natural gas transportation	3.5	3.5	3.5	1.0	—	—	11.5
Other	56.2	36.8	27.5	8.1	3.9	46.6	179.1
Total contractual commitments [(a)]	$ 968.1	$ 575.3	$ 487.7	$ 835.3	$ 750.2	$ 4,904.0	$ 8,520.6

[(a)] The Company expects to make contributions to the pension and other post-retirement plans beyond 2018 but the amounts are not yet determined. Amounts for years after 2014 are estimates based on information available in determining the amount for 2014. Actual amounts for years after 2014 could be significantly different than the estimated amounts in the table above.

Long-term debt includes current maturities. Long-term debt principal excludes $0.8 million of net premiums on senior notes. Variable rate interest obligations are based on rates as of December 31, 2013.

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 $2.0 million per year from 2014 to 2015 and approximately $0.4 million per year from 2016 to 2025, for a total of $8.2 million.

The Company expects to contribute $74.1 million to the pension and other post-retirement plans in 2014, of which the majority is expected to be paid by KCP&L. Additional contributions to the plans are expected beyond 2018 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 2014 are estimates based on information available in determining the amount for 2014. Actual amounts for years after 2014 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 $5.5 million for per year from 2014 to 2016 and $1.3 million per year for 2017 and 2018. La Cygne environmental project represents 100% of the contractual commitments related to environmental upgrades at KCP&L's La Cygne Station. KCP&L owns 50% of the La Cygne Station and expects to be reimbursed by the other owner for its 50% share of the costs. Non-regulated natural gas transportation consists of MPS Merchant's commitments. Other represents individual commitments entered into in the ordinary course of business.

At December 31, 2013, the total liability for unrecognized tax benefits for Great Plains Energy was $9.8 million, which is not included in the table above. Great Plains Energy is unable to determine reasonably reliable estimates of the period of cash settlement with the respective taxing authorities. See Note 22 to the consolidated financial statements for information regarding the recognition of tax benefits in the next twelve months, which is not expected to have a cash impact.

Great Plains Energy has other insignificant long-term liabilities recorded on its consolidated balance sheet at December 31, 2013, 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, 2013, Great Plains Energy has provided $140.6 million of credit support for GMO as follows:

- Great Plains Energy direct guarantees to GMO counterparties totaling $40.7 million, which expire in 2014 and 2015 and
- Great Plains Energy guarantees of GMO long-term debt totaling $99.9 million, which includes debt with maturity dates ranging from 2014-2023.

Great Plains Energy has also guaranteed GMO's commercial paper program. At December 31, 2013, GMO had $15.0 million of commercial paper outstanding. None of the guaranteed obligations are subject to default or prepayment as a result of a downgrade of GMO's credit ratings.

At December 31, 2013, KCP&L had issued letters of credit totaling $3.8 million as credit support to certain counterparties that expire in 2014. 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.

KCP&L has bond insurance policies for its EIRR Bond Series 2005 totaling $85.9 million. The insurance agreements between KCP&L and the issuers of the bond insurance policies provide for reimbursement by KCP&L for any amounts the insurers pay under the bond insurance policies. As the insurers' credit ratings are below KCP&L's credit ratings, the bonds are rated at KCP&L's credit ratings.

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The following table summarizes KCP&L's consolidated comparative results of operations.

	2013	2012
	(millions)	
Operating revenues	$ 1,671.4	$ 1,579.9
Fuel	(383.0)	(384.8)
Purchased power	(62.4)	(35.5)
Transmission	(37.3)	(24.0)
Gross margin [a]	1,188.7	1,135.6
Other operating expenses	(627.9)	(605.6)
Voluntary separation program	—	4.3
Depreciation and amortization	(198.3)	(185.6)
Operating income	362.5	348.7
Non-operating income and expenses	11.6	(4.2)
Interest charges	(125.3)	(127.6)
Income tax expense	(79.8)	(75.3)
Net income	$ 169.0	$ 141.6

[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 tables summarize KCP&L's gross margin and MWhs sold.

Gross Margin [a]	2013	% Change	2012
Retail revenues		(millions)	
Residential	$ 621.7	5	$ 594.0
Commercial	698.5	7	652.6
Industrial	126.6	8	117.0
Other retail revenues	12.8	2	12.5
Kansas property tax surcharge	(1.3)	N/M	4.8
Provision for rate refund	—	N/M	0.1
Fuel recovery mechanism	9.4	53	6.1
Total retail	1,467.7	6	1,387.1
Wholesale revenues	186.7	7	174.5
Other revenues	17.0	(7)	18.3
Operating revenues	1,671.4	6	1,579.9
Fuel	(383.0)	—	(384.8)
Purchased power	(62.4)	76	(35.5)
Transmission	(37.3)	55	(24.0)
Gross margin	$ 1,188.7	5	$ 1,135.6

[a] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

MWh Sales	2013	% Change	2012
Retail MWh sales		(thousands)	
Residential	5,428	—	5,440
Commercial	7,552	—	7,565
Industrial	1,784	(2)	1,818
Other retail MWh sales	87	(2)	89
Total retail	14,851	—	14,912
Wholesale MWh sales	6,832	(3)	7,067
Total MWh sales	21,683	(1)	21,979

KCP&L's gross margin increased $53.1 million in 2013 compared to 2012 primarily due to:

- an estimated $90 million increase primarily from new retail rates in Kansas effective January 1, 2013, and Missouri effective January 26, 2013;
- an estimated $24 million increase driven by an increase in weather-normalized retail demand;
- an estimated $4 million increase from the impact of an unplanned outage at Wolf Creek in the first quarter of 2012;
- an estimated $33 million decrease due to unfavorable weather driven by a 27% decrease in cooling degree days partially offset by the impact of favorable weather during the first and fourth quarters of 2013; and
- an estimated $32 million decrease primarily due to increased purchased power and transmission expense. Purchased power expense increased primarily due to increased MWh purchases under new wind generation power purchase agreements, which are included in new retail rates. Transmission expense increased primarily due to SPP base plan funding transmission charges, of which a portion is included in new retail rates.

KCP&L Other Operating Expenses ***(including operating and maintenance expenses, general taxes and other)***
KCP&L's other operating expenses increased $22.3 million in 2013 compared to 2012 primarily due to:

- a $5.7 million increase in pension expense corresponding to the resetting of pension expense trackers with the effective date of new retail rates;
- a $2.7 million increase relating to solar rebates provided to customers due to the deferral to a regulatory asset for recovery in future rates of $1.6 million in the first quarter of 2012 and $1.1 million of regulatory asset amortization in 2013; and
- a $6.5 million increase in general taxes driven by increased property taxes.

These increases were partially offset by a $2.4 million decrease in Wolf Creek operating and maintenance expenses primarily due to an unplanned outage in the first quarter of 2012, mainly offset by higher operating and maintenance expenses in 2013.

KCP&L Voluntary Separation Program
In 2012, KCP&L deferred $4.3 million of expense related to the voluntary separation program to a regulatory asset for recovery in rates beginning January 1, 2013, pursuant to KCP&L's December 2012 KCC rate order.

KCP&L Depreciation and Amortization
KCP&L's depreciation and amortization costs increased $12.7 million in 2013 compared to 2012 driven by higher depreciation rates for KCP&L as well as increased depreciation expense for other capital additions.

KCP&L Non-Operating Income and Expenses
KCP&L's non-operating income and expenses increased $15.8 million in 2013 compared to 2012 primarily due to a $12.8 million increase in the equity component of AFUDC.

KCP&L Income Tax Expense
KCP&L's income tax expense increased $4.5 million in 2013 compared to 2012 primarily due to increased pre-tax income.

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, 2013, 5% 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 5% and 7%, respectively, at December 31, 2013.

Great Plains Energy had $9.0 million of notes payable outstanding at December 31, 2013. The principal amount of the notes payable, which will vary during the year, drives Great Plains Energy's notes payable interest expense. Assuming that $9.0 million of notes payable was outstanding for all of 2014, a hypothetical 10% increase in interest rates associated with short-term variable rate debt would result in an immaterial increase in interest expense for 2014.

Great Plains Energy and KCP&L had $108.2 million and $93.2 million, respectively, of commercial paper outstanding at December 31, 2013. 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 that $108.2 million and $93.2 million of commercial paper was outstanding for all of 2014 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 2014. Assuming that $108.2 million and $93.2 million of commercial paper was outstanding for all of 2014 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 $1.1 million for Great Plains Energy and $0.9 million for KCP&L in 2014.

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 also enters into additional power purchase transactions with the objective of obtaining the most economical energy to meet its physical delivery obligations to customers. 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 continually evaluates its system requirements, the availability of generating units, the availability and cost of fuel supply, the availability and cost of purchased power and the requirements of other electric systems; therefore, the impact of the hypothetical amounts that follow could be significantly reduced depending on the system requirements and market prices at the time of the increases. A hypothetical 10% increase in the market price of power could result in a $0.2 million decrease in operating income for 2014 related to purchased power. In 2014, approximately 77% of KCP&L's net MWhs generated are expected to be coal-fired. KCP&L currently has approximately 70% of its coal requirements for 2014 under contract. A hypothetical 10% increase in the market price of coal could result in an approximate $5.6 million increase in fuel expense for 2014. KCP&L has also implemented price risk mitigation measures to reduce its exposure to high natural gas prices. A hypothetical 10% increase in natural gas and oil market prices could result in an immaterial increase in fuel expense for 2014. At December 31, 2013, KCP&L had no hedges for projected natural gas usage for generation requirements to serve KCP&L Missouri retail load and firm MWh sales. KCP&L's Kansas ECA allows for the recovery of increased fuel and purchased power costs from Kansas retail customers. KCP&L's Missouri retail rates do not contain a fuel recovery mechanism, meaning that changes in fuel costs create a regulatory lag.

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, 2013, was $11.9 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, 2013, 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 $5.3 million reduction in the value of the decommissioning trust funds at December 31, 2013. A hypothetical 10% decrease in equity prices would have resulted in a $12.8 million reduction in the fair value of the equity securities at December 31, 2013. 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

GREAT PLAINS ENERGY INCORPORATED

Consolidated Statements of Comprehensive Income

Year Ended December 31	2013	2012	2011
Operating Revenues	(millions, except per share amounts)		
Electric revenues	**$ 2,446.3**	$ 2,309.9	$ 2,318.0
Operating Expenses			
Fuel	**539.5**	539.5	483.8
Purchased power	**125.9**	94.0	203.4
Transmission	**53.2**	35.4	30.2
Utility operating and maintenance expenses	**671.4**	647.3	658.2
Voluntary separation program	**—**	(4.3)	12.7
Depreciation and amortization	**289.7**	272.3	273.1
General taxes	**194.4**	179.3	170.9
Other	**3.0**	7.5	5.9
Total	**1,877.1**	1,771.0	1,838.2
Operating income	**569.2**	538.9	479.8
Non-operating income	**18.4**	7.3	5.9
Non-operating expenses	**(9.6)**	(20.5)	(8.2)
Interest charges	**(198.4)**	(220.8)	(218.4)
Income before income tax expense and loss from equity investments	**379.6**	304.9	259.1
Income tax expense	**(129.2)**	(104.6)	(84.8)
Loss from equity investments, net of income taxes	**(0.2)**	(0.4)	(0.1)
Net income	**250.2**	199.9	174.2
Less: Net loss attributable to noncontrolling interest	**—**	—	0.2
Net income attributable to Great Plains Energy	**250.2**	199.9	174.4
Preferred stock dividend requirements	**1.6**	1.6	1.6
Earnings available for common shareholders	**$ 248.6**	$ 198.3	$ 172.8
Average number of basic common shares outstanding	**153.5**	145.5	135.6
Average number of diluted common shares outstanding	**153.7**	147.2	138.7
Basic earnings per common share	**$ 1.62**	$ 1.36	$ 1.27
Diluted earnings per common share	**$ 1.62**	$ 1.35	$ 1.25
Comprehensive Income			
Net income	**$ 250.2**	$ 199.9	$ 174.2
Other comprehensive income			
Derivative hedging activity			
Loss on derivative hedging instruments	**—**	(0.1)	(5.9)
Income tax benefit	**—**	—	2.3
Net loss on derivative hedging instruments	**—**	(0.1)	(3.6)
Reclassification to expenses, net of tax	**11.6**	12.6	10.4
Derivative hedging activity, net of tax	**11.6**	12.5	6.8
Defined benefit pension plans			
Net gain (loss) arising during period	**2.1**	(2.3)	(1.2)
Income tax (expense) benefit	**(0.9)**	0.9	0.4
Net gain (loss) arising during period, net of tax	**1.2**	(1.4)	(0.8)
Amortization of net losses included in net periodic benefit costs, net of tax	**0.3**	0.3	0.3
Change in unrecognized pension expense, net of tax	**1.5**	(1.1)	(0.5)
Total other comprehensive income	**13.1**	11.4	6.3
Comprehensive income	**263.3**	211.3	180.5
Less: comprehensive loss attributable to noncontrolling interest	**—**	—	0.2
Comprehensive income attributable to Great Plains Energy	**$ 263.3**	$ 211.3	$ 180.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Balance Sheets

	December 31	
	2013	2012
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 10.6**	$ 9.3
Funds on deposit	**0.8**	1.0
Receivables, net	**162.2**	154.5
Accounts receivable pledged as collateral	**175.0**	174.0
Fuel inventories, at average cost	**76.4**	95.1
Materials and supplies, at average cost	**152.3**	151.3
Deferred refueling outage costs	**29.5**	11.9
Refundable income taxes	**10.5**	9.5
Deferred income taxes	**80.3**	88.5
Assets held for sale (Note 12)	**36.2**	—
Prepaid expenses and other assets	**33.2**	28.6
Total	**767.0**	723.7
Utility Plant, at Original Cost		
Electric	**11,575.3**	11,160.5
Less - accumulated depreciation	**4,628.4**	4,424.2
Net utility plant in service	**6,946.9**	6,736.3
Construction work in progress	**736.7**	584.5
Nuclear fuel, net of amortization of $161.4 and $157.4	**62.8**	81.3
Total	**7,746.4**	7,402.1
Investments and Other Assets		
Nuclear decommissioning trust fund	**183.9**	154.7
Regulatory assets	**849.7**	1,120.9
Goodwill	**169.0**	169.0
Other	**79.4**	76.9
Total	**1,282.0**	1,521.5
Total	**$ 9,795.4**	$ 9,647.3

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Balance Sheets

	December 31	
	2013	2012
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Notes payable	**$ 9.0**	$ 12.0
Collateralized note payable	**175.0**	174.0
Commercial paper	**108.2**	530.1
Current maturities of long-term debt	**1.1**	263.1
Accounts payable	**327.4**	330.2
Accrued taxes	**29.7**	27.1
Accrued interest	**45.4**	41.5
Accrued compensation and benefits	**47.3**	44.8
Pension and post-retirement liability	**3.2**	2.8
Other	**23.5**	23.9
Total	**769.8**	1,449.5
Deferred Credits and Other Liabilities		
Deferred income taxes	**964.8**	832.4
Deferred tax credits	**127.4**	128.8
Asset retirement obligations	**158.8**	149.3
Pension and post-retirement liability	**360.5**	557.5
Regulatory liabilities	**264.0**	283.8
Other	**121.0**	110.2
Total	**1,996.5**	2,062.0
Capitalization		
Great Plains Energy common shareholders' equity		
Common stock - 250,000,000 shares authorized without par value		
153,995,621 and 153,779,806 shares issued, stated value	**2,631.1**	2,624.7
Retained earnings	**871.4**	758.8
Treasury stock - 129,290 and 250,236 shares, at cost	**(2.8)**	(5.1)
Accumulated other comprehensive loss	**(25.3)**	(38.4)
Total	**3,474.4**	3,340.0
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	**10.0**	10.0
4.50% - 100,000 shares issued	**10.0**	10.0
4.20% - 70,000 shares issued	**7.0**	7.0
4.35% - 120,000 shares issued	**12.0**	12.0
Total	**39.0**	39.0
Long-term debt (Note 11)	**3,515.7**	2,756.8
Total	**7,029.1**	6,135.8
Commitments and Contingencies (Note 15)		
Total	**$ 9,795.4**	$ 9,647.3

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	2013	2012	2011
Cash Flows from Operating Activities		(millions)	
Net income	**$ 250.2**	$ 199.9	$ 174.2
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**289.7**	272.3	273.1
Amortization of:			
Nuclear fuel	**22.8**	24.7	21.4
Other	**57.5**	36.0	12.7
Deferred income taxes, net	**134.0**	121.2	111.2
Investment tax credit amortization	**(1.7)**	(2.4)	(2.2)
Loss from equity investments, net of income taxes	**0.2**	0.4	0.1
Other operating activities (Note 2)	**24.1**	11.7	(147.5)
Net cash from operating activities	**776.8**	663.8	443.0
Cash Flows from Investing Activities			
Utility capital expenditures	**(669.0)**	(610.2)	(456.6)
Allowance for borrowed funds used during construction	**(11.8)**	(5.3)	(5.8)
Purchases of nuclear decommissioning trust investments	**(73.5)**	(24.2)	(18.5)
Proceeds from nuclear decommissioning trust investments	**70.2**	20.9	15.1
Other investing activities	**(21.7)**	(19.6)	(19.9)
Net cash from investing activities	**(705.8)**	(638.4)	(485.7)
Cash Flows from Financing Activities			
Issuance of common stock	**4.9**	293.0	5.9
Issuance of long-term debt	**762.5**	—	747.1
Issuance fees	**(9.0)**	(2.9)	(10.7)
Repayment of long-term debt	**(265.3)**	(513.8)	(598.5)
Net change in short-term borrowings	**(424.9)**	253.1	16.0
Net change in collateralized short-term borrowings	**1.0**	79.0	—
Dividends paid	**(137.3)**	(125.5)	(115.1)
Other financing activities	**(1.6)**	(5.2)	(6.6)
Net cash from financing activities	**(69.7)**	(22.3)	38.1
Net Change in Cash and Cash Equivalents	**1.3**	3.1	(4.6)
Cash and Cash Equivalents at Beginning of Year	**9.3**	6.2	10.8
Cash and Cash Equivalents at End of Year	**$ 10.6**	$ 9.3	$ 6.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Statements of Common Shareholders' Equity and Noncontrolling Interest

Year Ended December 31	2013		2012		2011	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Common Stock			(millions, except share amounts)			
Beginning balance	**153,779,806**	**$ 2,624.7**	136,406,306	$ 2,330.6	136,113,954	$ 2,324.4
Issuance of common stock	**215,815**	**4.9**	17,373,500	293.0	292,352	5.9
Equity compensation expense, net of forfeitures		**0.4**		0.3		0.3
Unearned Compensation						
Issuance of restricted common stock		**(1.8)**		(3.3)		(3.5)
Forfeiture of restricted common stock		**0.1**		1.3		0.9
Compensation expense recognized		**2.1**		2.3		2.3
Other		**0.7**		0.5		0.3
Ending balance	**153,995,621**	**2,631.1**	153,779,806	2,624.7	136,406,306	2,330.6
Retained Earnings						
Beginning balance		**758.8**		684.7		626.5
Net income attributable to Great Plains Energy		**250.2**		199.9		174.4
Loss on reissuance of treasury stock		**—**		(0.2)		(0.7)
Dividends:						
Common stock ($0.8825, $0.855 and $0.835 per share)		**(135.7)**		(123.9)		(113.5)
Preferred stock - at required rates		**(1.6)**		(1.6)		(1.6)
Performance shares		**(0.3)**		(0.1)		(0.4)
Ending balance		**871.4**		758.8		684.7
Treasury Stock						
Beginning balance	**(250,236)**	**(5.1)**	(264,567)	(5.6)	(400,889)	(8.9)
Treasury shares acquired	**(73,201)**	**(1.6)**	(164,454)	(3.3)	(125,234)	(2.4)
Treasury shares reissued	**194,147**	**3.9**	178,785	3.8	261,556	5.7
Ending balance	**(129,290)**	**(2.8)**	(250,236)	(5.1)	(264,567)	(5.6)
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(38.4)**		(49.8)		(56.1)
Derivative hedging activity, net of tax		**11.6**		12.5		6.8
Change in unrecognized pension expense, net of tax		**1.5**		(1.1)		(0.5)
Ending balance		**(25.3)**		(38.4)		(49.8)
Total Great Plains Energy Common Shareholders' Equity		**$ 3,474.4**		$ 3,340.0		$ 2,959.9
Noncontrolling Interest						
Beginning balance		**$ —**		$ 1.0		$ 1.2
Net loss attributable to noncontrolling interest		**—**		—		(0.2)
Distribution		**—**		(1.0)		—
Ending balance		**$ —**		$ —		$ 1.0

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	2013	2012	2011
Operating Revenues		(millions)	
Electric revenues	**$ 1,671.4**	$ 1,579.9	$ 1,558.3
Operating Expenses			
Fuel	**383.0**	384.8	333.5
Purchased power	**62.4**	35.5	70.8
Transmission	**37.3**	24.0	18.8
Operating and maintenance expenses	**475.9**	460.1	470.9
Voluntary separation program	—	(4.3)	9.2
Depreciation and amortization	**198.3**	185.6	193.1
General taxes	**152.0**	145.5	139.7
Other	—	—	1.1
Total	**1,308.9**	1,231.2	1,237.1
Operating income	**362.5**	348.7	321.2
Non-operating income	**16.3**	4.4	2.9
Non-operating expenses	**(4.7)**	(8.6)	(3.9)
Interest charges	**(125.3)**	(127.6)	(115.6)
Income before income tax expense	**248.8**	216.9	204.6
Income tax expense	**(79.8)**	(75.3)	(69.1)
Net income	**$ 169.0**	$ 141.6	$ 135.5
Comprehensive Income			
Net income	**$ 169.0**	$ 141.6	$ 135.5
Other comprehensive income			
Derivative hedging activity			
Loss on derivative hedging instruments	—	(0.1)	(0.6)
Income tax benefit	—	—	0.2
Net loss on derivative hedging instruments	—	(0.1)	(0.4)
Reclassification to expenses, net of tax	**5.6**	5.7	5.4
Derivative hedging activity, net of tax	**5.6**	5.6	5.0
Total other comprehensive income	**5.6**	5.6	5.0
Comprehensive income	**$ 174.6**	$ 147.2	$ 140.5

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	
	2013	2012
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 4.0**	$ 5.2
Funds on deposit	**0.7**	0.1
Receivables, net	**179.6**	163.2
Accounts receivable pledged as collateral	**110.0**	110.0
Fuel inventories, at average cost	**50.3**	63.6
Materials and supplies, at average cost	**109.0**	110.1
Deferred refueling outage costs	**29.5**	11.9
Refundable income taxes	**15.1**	9.1
Deferred income taxes	**—**	4.6
Assets held for sale (Note 12)	**4.7**	—
Prepaid expenses and other assets	**27.5**	23.8
Total	**530.4**	501.6
Utility Plant, at Original Cost		
Electric	**8,274.9**	7,971.4
Less - accumulated depreciation	**3,518.3**	3,374.4
Net utility plant in service	**4,756.6**	4,597.0
Construction work in progress	**660.4**	486.5
Nuclear fuel, net of amortization of $161.4 and $157.4	**62.8**	81.3
Total	**5,479.8**	5,164.8
Investments and Other Assets		
Nuclear decommissioning trust fund	**183.9**	154.7
Regulatory assets	**614.1**	853.2
Other	**31.0**	29.5
Total	**829.0**	1,037.4
Total	**$ 6,839.2**	$ 6,703.8

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	
	2013	2012
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Collateralized note payable	**$ 110.0**	$ 110.0
Commercial paper	**93.2**	361.0
Current maturities of long-term debt	**—**	0.4
Accounts payable	**240.0**	254.0
Accrued taxes	**23.8**	21.9
Accrued interest	**29.1**	27.7
Accrued compensation and benefits	**47.3**	44.8
Pension and post-retirement liability	**1.9**	1.4
Deferred income taxes	**1.7**	—
Other	**13.0**	12.8
Total	**560.0**	834.0
Deferred Credits and Other Liabilities		
Deferred income taxes	**922.1**	836.4
Deferred tax credits	**125.3**	126.1
Asset retirement obligations	**141.7**	133.2
Pension and post-retirement liability	**339.9**	534.5
Regulatory liabilities	**168.3**	153.0
Other	**90.4**	88.2
Total	**1,787.7**	1,871.4
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	**636.4**	559.4
Accumulated other comprehensive loss	**(20.2)**	(25.8)
Total	**2,179.3**	2,096.7
Long-term debt (Note 11)	**2,312.2**	1,901.7
Total	**4,491.5**	3,998.4
Commitments and Contingencies (Note 15)		
Total	**$ 6,839.2**	$ 6,703.8

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	2013	2012	2011
Cash Flows from Operating Activities		(millions)	
Net income	**$ 169.0**	$ 141.6	$ 135.5
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**198.3**	185.6	193.1
Amortization of:			
Nuclear fuel	**22.8**	24.7	21.4
Other	**34.3**	30.1	29.5
Deferred income taxes, net	**92.1**	60.2	80.6
Investment tax credit amortization	**(1.1)**	(1.8)	(1.5)
Other operating activities (Note 2)	**(9.2)**	27.9	(118.3)
Net cash from operating activities	**506.2**	468.3	340.3
Cash Flows from Investing Activities			
Utility capital expenditures	**(521.9)**	(482.0)	(336.5)
Allowance for borrowed funds used during construction	**(10.6)**	(3.7)	(2.9)
Purchases of nuclear decommissioning trust investments	**(73.5)**	(24.2)	(18.5)
Proceeds from nuclear decommissioning trust investments	**70.2**	20.9	15.1
Net money pool lending	**—**	—	12.1
Other investing activities	**(12.4)**	(11.7)	(9.7)
Net cash from investing activities	**(548.2)**	(500.7)	(340.4)
Cash Flows from Financing Activities			
Issuance of long-term debt	**412.5**	—	397.4
Repayment of long-term debt	**(2.6)**	(12.7)	(263.1)
Net change in short-term borrowings	**(267.8)**	134.0	(36.5)
Net change in collateralized short-term borrowings	**—**	15.0	—
Net money pool borrowings	**(3.6)**	(4.7)	6.7
Dividends paid to Great Plains Energy	**(92.0)**	(96.0)	(100.0)
Issuance fees	**(5.7)**	—	(6.1)
Other	**—**	0.1	—
Net cash from financing activities	**40.8**	35.7	(1.6)
Net Change in Cash and Cash Equivalents	**(1.2)**	3.3	(1.7)
Cash and Cash Equivalents at Beginning of Year	**5.2**	1.9	3.6
Cash and Cash Equivalents at End of Year	**$ 4.0**	$ 5.2	$ 1.9

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	2013		2012		2011	
	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		**559.4**		513.8		478.3
Net income		**169.0**		141.6		135.5
Dividends:						
Common stock held by Great Plains Energy		**(92.0)**		(96.0)		(100.0)
Ending balance		**636.4**		559.4		513.8
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(25.8)**		(31.4)		(36.4)
Derivative hedging activity, net of tax		**5.6**		5.6		5.0
Ending balance		**(20.2)**		(25.8)		(31.4)
Total Common Shareholder's Equity		**$ 2,179.3**		$ 2,096.7		$ 2,045.5

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
KANSAS CITY POWER & LIGHT COMPANY

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 operations or active subsidiaries 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.
- GPE Transmission Holding Company, LLC (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 23 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 designated as normal purchases and normal sales (NPNS) and cash flow hedges 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 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 cash flow hedges or non-hedging derivatives, which are recorded as assets or liabilities on the consolidated balance sheets at fair value. In addition, if a derivative instrument is designated as a cash flow hedge, Great Plains Energy and KCP&L document the method of determining hedge effectiveness and measuring ineffectiveness. See Note 19 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). Great Plains Energy and KCP&L classify cash flows from derivative instruments in the same category as the cash flows from the items being hedged.

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 and averaged 6.1% in 2013, 2.0% in 2012 and 2.9% in 2011 for KCP&L. The rates used to compute gross AFUDC for GMO averaged 2.1% in 2013, 2.4% in 2012 and 5.4% in 2011.

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	2013	2012
Utility plant, at original cost	(millions)	
Generation (20 - 60 years)	$ 6,874.6	$ 6,697.1
Transmission (15 - 70 years)	794.0	754.0
Distribution (8 - 66 years)	3,149.4	3,019.6
General (5 - 50 years)	757.3	689.8
Total [a]	$ 11,575.3	$ 11,160.5

[a] Includes $107.8 million and $104.5 million at December 31, 2013 and 2012, respectively, of land and other assets that are not depreciated.

KCP&L

December 31	2013	2012
Utility plant, at original cost	(millions)	
Generation (20 - 60 years)	$ 5,288.3	$ 5,140.0
Transmission (15 - 70 years)	433.7	414.7
Distribution (8 - 55 years)	1,970.2	1,893.8
General (5 - 50 years)	582.7	522.9
Total [a]	$ 8,274.9	$ 7,971.4

[a] Includes $54.1 million and $54.7 million at December 31, 2013 and 2012, 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 $265.4 million, $251.4 million and $239.9 million for 2013, 2012 and 2011, respectively. KCP&L's depreciation expense was $179.2 million, $168.0 million and $162.0 million for 2013, 2012 and 2011, 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 income. KCP&L's gross receipts taxes collected from Missouri customers were $58.9 million, $55.8 million and $55.6 million in 2013, 2012 and 2011, 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 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 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 EPS, preferred stock dividend requirements and net loss attributable to noncontrolling interest 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, restricted stock, stock options and Equity Units. Great Plains Energy settled the Equity Units in June 2012.

The following table reconciles Great Plains Energy's basic and diluted EPS.

	2013	2012	2011
Income	(millions, except per share amounts)		
Net income	$ 250.2	$ 199.9	$ 174.2
Less: net loss attributable to noncontrolling interest	—	—	(0.2)
Less: preferred stock dividend requirements	1.6	1.6	1.6
Earnings available for common shareholders	$ 248.6	$ 198.3	$ 172.8
Common Shares Outstanding			
Average number of common shares outstanding	153.5	145.5	135.6
Add: effect of dilutive securities	0.2	1.7	3.1
Diluted average number of common shares outstanding	153.7	147.2	138.7
Basic EPS	$ 1.62	$ 1.36	$ 1.27
Diluted EPS	$ 1.62	$ 1.35	$ 1.25

Anti-dilutive shares excluded from the computation of diluted EPS are detailed in the following table.

	2013	2012	2011
Performance shares	548,242	—	50,897
Restricted stock shares	2,228	3,781	43,641
Stock options	—	—	6,000

Dividends Declared

In February 2014, Great Plains Energy's Board of Directors (Board) declared a quarterly dividend of $0.23 per share on Great Plains Energy's common stock. The common dividend is payable March 20, 2014, to shareholders of record as of February 27, 2014. The Board also declared regular dividends on Great Plains Energy's preferred stock, payable June 1, 2014, to shareholders of record as of May 9, 2014.

In February 2014, KCP&L's Board of Directors declared a cash dividend payable to Great Plains Energy of $18 million payable on March 19, 2014.

2. SUPPLEMENTAL CASH FLOW INFORMATION

Great Plains Energy Other Operating Activities

Year Ended December 31	2013	2012	2011
Cash flows affected by changes in:		(millions)	
Receivables	$ (7.1)	$ 76.8	$ 3.6
Accounts receivable pledged as collateral	(1.0)	(79.0)	—
Fuel inventories	18.7	(6.1)	(3.9)
Materials and supplies	(1.0)	(11.0)	(7.5)
Accounts payable	26.4	57.3	5.7
Accrued taxes	2.2	(7.8)	1.4
Accrued interest	3.9	(35.2)	1.5
Deferred refueling outage costs	(17.6)	15.6	(17.9)
Pension and post-retirement benefit obligations	31.3	14.4	(56.0)
Allowance for equity funds used during construction	(14.1)	(1.3)	(1.0)
Interest rate hedge settlements	—	—	(26.1)
Fuel recovery mechanism	(1.3)	22.5	(1.7)
Uncertain tax positions	(0.8)	(4.7)	(20.8)
Other	(15.5)	(29.8)	(24.8)
Total other operating activities	$ 24.1	$ 11.7	$ (147.5)
Cash paid during the period:			
Interest	$ 170.8	$ 247.9	$ 254.4
Income taxes	$ —	$ 3.3	$ 2.8
Non-cash investing activities:			
Liabilities accrued for capital expenditures	$ 48.1	$ 57.5	$ 39.7

KCP&L Other Operating Activities

Year Ended December 31	2013	2012	2011
Cash flows affected by changes in:		(millions)	
Receivables	$ (12.6)	$ 8.8	$ (20.2)
Accounts receivable pledged as collateral	—	(15.0)	—
Fuel inventories	13.3	(4.6)	(14.1)
Materials and supplies	1.1	(9.0)	(6.7)
Accounts payable	7.3	48.3	11.0
Accrued taxes	(3.7)	(2.0)	2.7
Accrued interest	1.4	(2.3)	3.8
Deferred refueling outage costs	(17.6)	15.6	(17.9)
Pension and post-retirement benefit obligations	35.7	18.0	(45.6)
Allowance for equity funds used during construction	(14.1)	(1.3)	(0.7)
Fuel recovery mechanism	(1.8)	5.1	(5.8)
Uncertain tax positions	(10.5)	1.8	(10.4)
Other	(7.7)	(35.5)	(14.4)
Total other operating activities	$ (9.2)	$ 27.9	$ (118.3)
Cash paid during the period:			
Interest	$ 111.7	$ 118.0	$ 111.3
Income taxes	$ 4.6	$ 18.0	$ 0.1
Non-cash investing activities:			
Liabilities accrued for capital expenditures	$ 40.5	$ 48.4	$ 32.0

3. RECEIVABLES

Great Plains Energy's and KCP&L's receivables are detailed in the following table.

	December 31	
	2013	2012
Great Plains Energy	(millions)	
Customer accounts receivable - billed	$ 1.5	$ —
Customer accounts receivable - unbilled	74.6	58.3
Allowance for doubtful accounts - customer accounts receivable	(2.5)	(2.6)
Other receivables	88.6	98.8
Total	$ 162.2	$ 154.5
KCP&L		
Customer accounts receivable - billed	$ 1.3	$ —
Customer accounts receivable - unbilled	51.2	42.9
Allowance for doubtful accounts - customer accounts receivable	(1.1)	(1.5)
Intercompany receivables	50.4	40.0
Other receivables	77.8	81.8
Total	$ 179.6	$ 163.2

Great Plains Energy's and KCP&L's other receivables at December 31, 2013 and 2012 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, 2013 and 2012, Great Plains Energy's accounts receivable pledged as collateral and the corresponding short-term collateralized note payable were $175.0 million and $174.0 million, respectively. At December 31, 2013 and 2012, KCP&L's accounts receivable pledged as collateral and the corresponding short-term collateralized note payable were $110.0 million.

KCP&L and GMO each sell their receivables at a fixed price based upon the expected cost of funds and charge-offs. These costs comprise KCP&L's and GMO's loss on the sale of accounts receivable. KCP&L and GMO service the receivables and receive annual servicing fees of 1.5% and 1.25%, respectively, of the outstanding principal amount of the receivables sold to KCP&L Receivables Company and GMO Receivables Company. KCP&L and GMO do not recognize a servicing asset or liability because management determined the collection agent fees earned by KCP&L and GMO approximate market value. KCP&L's agreement expires in September 2014 and allows for $110 million in aggregate outstanding principal amount at any time. GMO's agreement expires in September 2014 and allows for $80 million in aggregate outstanding principal during the period of June 1 through October 31 and $65 million in aggregate outstanding principal during the period of November 1 through May 31 of each year.

Information regarding KCP&L's sale of accounts receivable to KCP&L Receivables Company and GMO's sale of accounts receivable to GMO Receivables Company is reflected in the following tables.

2013	KCP&L	KCP&L Receivables Company	Consolidated KCP&L	GMO	GMO Receivables Company	Consolidated Great Plains Energy
			(millions)			
Receivables (sold) purchased	$ (1,517.2)	$ 1,517.2	$ —	$ (834.7)	$ 834.7	$ —
Gain (loss) on sale of accounts receivable [a]	(19.2)	19.1	(0.1)	(10.6)	10.5	(0.2)
Servicing fees received (paid)	2.6	(2.6)	—	1.4	(1.4)	—
Fees paid to outside investor	—	(1.2)	(1.2)	—	(0.7)	(1.9)
Cash from customers (transferred) received	(1,516.2)	1,516.2	—	(830.9)	830.9	—
Cash received from (paid for) receivables purchased	1,497.2	(1,497.2)	—	820.5	(820.5)	—
Interest on intercompany note received (paid)	0.3	(0.3)	—	0.1	(0.1)	—

2012	KCP&L	KCP&L Receivables Company	Consolidated KCP&L	GMO	GMO Receivables Company	Consolidated Great Plains Energy
			(millions)			
Receivables (sold) purchased	$ (1,436.0)	$ 1,436.0	$ —	$ (597.8)	$ 597.8	$ —
Gain (loss) on sale of accounts receivable [a]	(18.2)	18.3	0.1	(7.6)	6.6	(0.9)
Servicing fees received (paid)	2.5	(2.5)	—	0.9	(0.9)	—
Fees paid to outside investor	—	(1.2)	(1.2)	—	(0.5)	(1.7)
Cash from customers (transferred) received	(1,452.4)	1,452.4	—	(524.0)	524.0	—
Cash received from (paid for) receivables purchased	1,434.2	(1,434.2)	—	517.5	(517.5)	—
Interest on intercompany note received (paid)	0.3	(0.3)	—	0.1	(0.1)	—

[a] Any net gain (loss) is the result of the timing difference inherent in collecting receivables and over the life of the agreement will net to zero.

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. KCP&L pays 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. These disposal costs are charged to fuel expense. 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, and the DOE appealed that decision to the full NRC. In 2011, the NRC issued an evenly split decision on the appeal and ordered the licensing board to close out its work on the DOE's application due to a lack of funding. In August 2013, a federal court of appeals ruled that the NRC must resume its review of the DOE's application. Wolf Creek has an on-site storage facility designed to hold all spent fuel generated at the plant through 2025, and believes it will be able to expand on-site storage as needed past 2025. Management cannot predict when, or if, an 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 2011 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.

	Total Station	KCP&L's 47% Share
	(millions)	
Current cost of decommissioning (in 2011 dollars)	$ 630	$ 296
Future cost of decommissioning (in 2045-2053 dollars) [a]	1,788	840
Annual escalation factor	2.85%	
Annual return on trust assets [b]	5.13%	

[a] Total future cost over an eight year decommissioning period

[b] The 5.13% rate of return is through 2025. The rate then systematically decreases through 2053 to 0.76% based on the assumption that the fund's investment mix will become increasingly conservative as the decommissioning period approaches.

Nuclear Decommissioning Trust Fund

In 2013 and 2012, 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.

	2013	2012
Decommissioning Trust	(millions)	
Beginning balance January 1	$ 154.7	$ 135.3
Contributions	3.3	3.3
Earned income, net of fees	2.7	3.0
Net realized gains	1.7	1.0
Net unrealized gains	21.5	12.1
Ending balance December 31	$ 183.9	$ 154.7

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							
	2013				2012			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(millions)							
Equity securities	$ 83.7	$ 44.6	$ (0.6)	$ 127.7	$ 80.6	$ 21.1	$ (1.6)	$ 100.1
Debt securities	51.0	2.5	(0.7)	52.8	46.6	4.9	(0.1)	51.4
Other	3.4	—	—	3.4	3.2	—	—	3.2
Total	$ 138.1	$ 47.1	$ (1.3)	$ 183.9	$ 130.4	$ 26.0	$ (1.7)	$ 154.7

The weighted average maturity of debt securities held by the trust at December 31, 2013, was approximately 7 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:

	2013	2012	2011
	(millions)		
Realized gains	$ 2.4	$ 1.7	$ 1.0
Realized losses	(0.7)	(0.7)	(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 $13.6 billion. This limit of liability consists of the maximum available commercial insurance of $0.4 billion and the remaining $13.2 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 $34.4 million ($16.1 million, KCP&L's 47% share) per policy year.

5. REGULATORY MATTERS

KCP&L Kansas Abbreviated Rate Case Proceedings

In December 2013, KCP&L filed an abbreviated application with KCC to request an increase to its retail revenues of $12.1 million, including the recovery of costs to reflect the completion of certain components of environmental upgrades at the La Cygne Station, construction work in progress for those components of the upgrades still under construction and updates to certain regulatory asset amortizations. The previously approved return on equity and rate-making equity ratio for KCP&L will not be addressed in this case. Testimony from KCC staff and other parties regarding the case is expected in April 2014, with an evidentiary hearing to occur in May 2014. The increase to retail revenues is anticipated to be effective in August 2014.

KCP&L Missouri Rate Case Proceedings

On January 9, 2013, the MPSC issued an order for KCP&L authorizing an increase in annual revenues of $67.4 million effective January 26, 2013. An appeal of the January 9, 2013, MPSC order filed in February 2013 with the Missouri Court of Appeals, Western District (Court of Appeals) by the Missouri Energy Consumers Group (MECG) was dismissed in January 2014. The rates established by the January 9, 2013, MPSC order are effective unless and until modified by the MPSC or stayed by a court.

GMO Missouri Rate Case Proceedings

On January 9, 2013, the MPSC issued an order for GMO authorizing an increase in annual revenues of $26.2 million for its Missouri Public Service division and $21.7 million for its St. Joseph Light & Power division effective January 26, 2013. Appeals of the January 9, 2013, MPSC order were filed in February 2013 with the Court of Appeals by GMO and MECG regarding various issues. The rates established by the January 9, 2013, MPSC order are effective unless and until modified by the MPSC or stayed by a court.

KCP&L Missouri Energy Efficiency Investment Act Proceedings

In January 2014, KCP&L filed a request with the MPSC seeking to recover costs for new and enhanced demand side management programs under the Missouri Energy Efficiency Investment Act (MEEIA). If approved, the costs would be deferred to a regulatory asset and recovered through a rider mechanism beginning in June 2015. Testimony from MPSC staff and other parties regarding the case is expected at the end February 2014, with hearings to occur in March 2014. An order is expected in the second quarter of 2014.

KCP&L and GMO Transmission Cost Accounting Authority Order

In September 2013, KCP&L and GMO filed an application with the MPSC requesting an accounting authority order to defer transmission costs above or below the amount included in current base rates, including carrying costs, as a regulatory asset or liability with the recovery from or refund to Missouri retail customers to be determined in the next general rate case for each company. Hearings were held in January 2014 and a final order is expected in the first half of 2014.

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					
	2013			2012		
	KCP&L	GMO	Great Plains Energy	KCP&L	GMO	Great Plains Energy
Regulatory Assets			(millions)			
Taxes recoverable through future rates	$ 111.0	$ 25.4	$ 136.4	$ 114.7	$ 23.7	$ 138.4
Loss on reacquired debt	7.1 [a]	1.5 [a]	8.6	8.1	2.0	10.1
Cost of removal	1.0	—	1.0	2.8	—	2.8
Asset retirement obligations	34.8	16.0	50.8	31.5	14.9	46.4
Pension and post-retirement costs	310.0 [b]	91.2 [b]	401.2	541.2	129.7	670.9
Deferred customer programs	50.2 [c]	21.8 [d]	72.0	49.8	24.6	74.4
Rate case expenses	3.6 [e]	0.6 [f]	4.2	7.5	1.7	9.2
Fuel recovery mechanism	10.8 [e]	12.8 [e]	23.6	8.9	16.9	25.8
Acquisition transition costs	12.9 [g]	11.0 [g]	23.9	18.7	15.5	34.2
Derivative instruments	—	—	—	—	3.7	3.7
Iatan No. 1 and common facilities depreciation and carrying costs	15.3 [h]	5.7 [h]	21.0	15.9	5.9	21.8
Iatan No. 2 construction accounting costs	29.3 [i]	16.0 [i]	45.3	30.6	16.2	46.8
Kansas property tax surcharge	4.0 [e]	—	4.0	5.4	—	5.4
Solar rebates	13.0 [e]	32.3 [e]	45.3	5.8	10.0	15.8
Voluntary separation program	3.4 [j]	—	3.4	4.3	—	4.3
Other	7.7 [e]	1.3 [e]	9.0	8.0	2.9	10.9
Total	$ 614.1	$ 235.6	$ 849.7	$ 853.2	$ 267.7	$ 1,120.9
Regulatory Liabilities						
Emission allowances	$ 74.0	$ —	$ 74.0	$ 78.0	$ 0.1	$ 78.1
Asset retirement obligations	86.2	—	86.2	63.1	—	63.1
Pension	—	—	—	1.5	44.6	46.1
Cost of removal	—	68.1 [k]	68.1	—	64.0	64.0
Other	8.1	27.6	35.7	10.4	22.1	32.5
Total	$ 168.3	$ 95.7	$ 264.0	$ 153.0	$ 130.8	$ 283.8

[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, $288.5 million and $57.0 million for KCP&L and GMO, respectively, are not included in rate base and are amortized over various periods.

(c) $15.4 million not included in rate base and amortized over various periods.

(d) $2.1 million not included in rate base and amortized over various periods.

(e) Not included in rate base and amortized over various periods.

(f) Not included in rate base and amortized through 2014.

(g) Not included in rate base and amortized through 2016.

(h) Included in rate base and amortized through 2038.

(i) Included in rate base and amortized through 2058.

(j) Not included in rate base and amortized through 2017.

(k) 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, 2013. 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, 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, 2013		December 31, 2012	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(millions)			
Great Plains Energy				
Computer software	$ 255.4	$ (169.9)	$ 211.2	$ (152.9)
Asset improvements	26.5	(4.9)	26.5	(4.2)
KCP&L				
Computer software	$ 231.2	$ (156.5)	$ 189.9	$ (142.9)
Asset improvements	11.2	(1.1)	11.2	(0.8)

Great Plains Energy's and KCP&L's amortization expense related to intangible assets is detailed in the following table.

	2013	2012
	(millions)	
Great Plains Energy	$ 17.6	$ 15.6
KCP&L	14.3	13.2

The following table provides the estimated amortization expense related to Great Plains Energy's and KCP&L's intangible assets for 2014 through 2018 for the intangible assets included in the consolidated balance sheets at December 31, 2013.

	2014	2015	2016	2017	2018
			(millions)		
Great Plains Energy	$ 17.2	$ 15.1	$ 13.6	$ 9.5	$ 6.7
KCP&L	14.0	12.1	10.7	8.4	6.3

7. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations associated with tangible long-lived assets are those for which a legal obligation exists 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 and removal of storage tanks, ash ponds and landfills. GMO has AROs related to asbestos abatement and removal of storage tanks, ash ponds and landfills.

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.

The following table summarizes the change in Great Plains Energy's and KCP&L's AROs.

	Great Plains Energy		KCP&L	
	2013	2012	2013	2012
		(millions)		
Beginning balance	$ 149.3	$ 149.6	$ 133.2	$ 134.3
Revision in timing and/or estimates	—	(7.7)	—	(7.7)
Settlements	—	(1.8)	—	(1.8)
Accretion	9.5	9.2	8.5	8.4
Ending balance	$ 158.8	$ 149.3	$ 141.7	$ 133.2

8. PENSION PLANS, OTHER EMPLOYEE BENEFITS AND VOLUNTARY SEPARATION PROGRAM

Great Plains Energy incurs significant costs in providing defined benefit plans for substantially all active and inactive employees, including officers, of KCP&L, GMO 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 2013, 2012 and 2011, Great Plains Energy recorded pension settlement charges of $4.9 million, $0.8 million and $10.1 million, respectively, as a result of accelerated pension distributions. The 2011 distributions were related to the voluntary separation program which is explained in more detail below. The Companies deferred substantially all of the charges as a regulatory asset and will recover it over future periods pursuant to regulatory agreements.

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	
	2013	2012	2013	2012
Change in projected benefit obligation (PBO)		(millions)		
PBO at January 1	$ 1,130.5	$ 980.6	$ 186.5	$ 154.2
Service cost	41.2	35.4	4.4	3.3
Interest cost	47.2	48.9	7.7	7.8
Contribution by participants	—	—	6.2	6.7
Amendments	0.3	1.1	(6.0)	—
Actuarial (gain) loss	(118.4)	127.0	(26.1)	26.7
Benefits paid	(52.9)	(58.1)	(12.2)	(12.2)
Settlements	(40.5)	(4.4)	—	—
PBO at December 31	$ 1,007.4	$ 1,130.5	$ 160.5	$ 186.5
Change in plan assets				
Fair value of plan assets at January 1	$ 666.4	$ 591.1	$ 90.3	$ 77.4
Actual return on plan assets	70.9	71.2	(2.0)	1.4
Contributions by employer and participants	57.4	60.4	25.0	23.7
Benefits paid	(51.2)	(56.3)	(12.1)	(12.2)
Settlements	(40.5)	—	—	—
Fair value of plan assets at December 31	$ 703.0	$ 666.4	$ 101.2	$ 90.3
Funded status at December 31	$ (304.4)	$ (464.1)	$ (59.3)	$ (96.2)
Amounts recognized in the consolidated balance sheets				
Current pension and other post-retirement liability	$ (2.3)	$ (1.9)	$ (0.9)	$ (0.9)
Noncurrent pension liability and other post-retirement liability	(302.1)	(462.2)	(58.4)	(95.3)
Net amount recognized before regulatory treatment	(304.4)	(464.1)	(59.3)	(96.2)
Accumulated OCI or regulatory asset/liability	368.3	559.5	35.3	70.4
Net amount recognized at December 31	$ 63.9	$ 95.4	$ (24.0)	$ (25.8)
Amounts in accumulated OCI or regulatory asset/liability not yet recognized as a component of net periodic benefit cost:				
Actuarial loss	$ 147.7	$ 349.0	$ 19.2	$ 43.0
Prior service cost	5.6	7.3	16.6	29.8
Transition obligation	—	—	0.4	0.6
Other	215.0	203.2	(0.9)	(3.0)
Net amount recognized at December 31	$ 368.3	$ 559.5	$ 35.3	$ 70.4

	Pension Benefits			Other Benefits		
	2013	2012	2011	2013	2012	2011
Components of net periodic benefit costs			(millions)			
Service cost	$ 41.2	$ 35.4	$ 31.1	$ 4.4	$ 3.3	$ 3.1
Interest cost	47.2	48.9	49.6	7.7	7.8	7.8
Expected return on plan assets	(47.1)	(42.9)	(38.0)	(2.0)	(1.8)	(1.8)
Prior service cost	2.0	4.5	4.6	7.2	7.1	7.2
Recognized net actuarial (gain) loss	54.3	44.5	38.7	1.7	(0.2)	(0.5)
Transition obligation	—	—	—	0.2	1.1	1.3
Settlement charges	4.9	0.8	10.1	—	—	—
Net periodic benefit costs before regulatory adjustment	102.5	91.2	96.1	19.2	17.3	17.1
Regulatory adjustment	(16.8)	(15.5)	(27.9)	(2.4)	1.5	1.1
Net periodic benefit costs	85.7	75.7	68.2	16.8	18.8	18.2
Other changes in plan assets and benefit obligations recognized in OCI or regulatory assets/liabilities						
Current year net (gain) loss	(147.0)	97.9	114.8	(22.1)	27.1	6.7
Amortization of gain (loss)	(54.3)	(44.5)	(38.7)	(1.7)	0.2	0.5
Prior service cost	0.3	1.1	—	(6.0)	—	—
Amortization of prior service cost	(2.0)	(4.5)	(4.6)	(7.2)	(7.1)	(7.2)
Amortization of transition obligation	—	—	—	(0.2)	(1.1)	(1.3)
Other regulatory activity	11.8	17.7	17.1	2.1	(1.2)	(1.0)
Total recognized in OCI or regulatory asset/ liability	(191.2)	67.7	88.6	(35.1)	17.9	(2.3)
Total recognized in net periodic benefit costs and OCI or regulatory asset/liability	$ (105.5)	$ 143.4	$ 156.8	$ (18.3)	$ 36.7	$ 15.9

For financial reporting purposes, the estimated prior service cost and net loss for the defined benefit plans that will be amortized from accumulated OCI or a regulatory asset into net periodic benefit cost in 2014 are $1.0 million and $49.6 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, net gain and transition costs for the other post-retirement benefit plans that will be amortized from accumulated OCI or a regulatory asset into net periodic benefit cost in 2014 are $3.1 million, $0.1 million and $0.2 million, respectively.

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $889.2 million and $985.8 million at December 31, 2013 and 2012, 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.

	2013	2012
Pension plans with the PBO in excess of plan assets	(millions)	
Projected benefit obligation	$ 1,007.4	$ 1,130.5
Fair value of plan assets	703.0	666.4
Pension plans with the ABO in excess of plan assets		
Accumulated benefit obligation	$ 889.2	$ 985.8
Fair value of plan assets	703.0	666.4
Other post-retirement benefit plans with the APBO in excess of plan assets		
Accumulated other post-retirement benefit obligation	$ 160.5	$ 186.5
Fair value of plan assets	101.2	90.3

The GMO Supplemental Executive Retirement Plan (SERP) is reflected as an unfunded ABO of $21.5 million. Great Plains Energy has approximately $17.9 million of assets in a non-qualified trust for this plan as of December 31, 2013, 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**		**Other Benefits**	
	2013	**2012**	**2013**	**2012**
Discount rate	5.03%	4.17%	4.92%	4.13%
Rate of compensation increase	3.69%	3.69%	3.50%	3.50%

Weighted-average assumptions used to determine net costs for years ended December 31	**Pension Benefits**		**Other Benefits**	
	2013	**2012**	**2013**	**2012**
Discount rate	4.17%	5.01%	4.13%	5.03%
Expected long-term return on plan assets	7.24%	7.29%	2.62% *	2.59% *
Rate of compensation increase	3.69%	4.08%	3.50%	4.07%

*after tax

Great Plains Energy expects to contribute $62.8 million to the pension plans in 2014 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 $11.3 million to other post-retirement benefit plans in 2014, 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 2023.

	Pension Benefits	**Other Benefits**
	(millions)	
2014	$ 67.0	$ 7.8
2015	65.3	8.3
2016	69.1	8.9
2017	71.9	9.3
2018	73.6	9.7
2019-2023	401.3	52.1

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 25% U.S. large cap and small cap equity securities, 23% international equity securities, 35% fixed income securities, 7% real estate, 6% 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, 2013 and 2012, by asset category are in the following tables.

		Fair Value Measurements Using		
Description	**December 31 2013**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		(millions)		
Pension Plans				
Equity securities				
U.S. [a]	$ 193.7	$ 80.5	$ 113.2	$ —
International [b]	167.1	39.9	127.2	—
Real estate [c]	49.1	—	5.4	43.7
Commodities [d]	34.8	—	34.8	—
Fixed income securities				
Fixed income funds [e]	181.3	27.1	154.2	—
U.S. Treasury	2.6	2.6	—	—
U.S. Agency, state and local obligations	17.1	—	17.1	—
U.S. corporate bonds [f]	25.6	—	25.6	—
Foreign corporate bonds	2.3	—	2.3	—
Hedge funds [g]	23.1	—	—	23.1
Cash equivalents	3.0	3.0	—	—
Other	3.3	—	3.3	—
Total	$ 703.0	$ 153.1	$ 483.1	$ 66.8

Description	December 31 2012	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)
		(millions)		
Pension Plans				
Equity securities				
U.S. [a]	$ 169.6	$ 69.7	$ 99.9	$ —
International [b]	151.2	36.6	114.6	—
Real estate [c]	43.4	—	5.0	38.4
Commodities [d]	37.3	—	37.3	—
Fixed income securities				
Fixed income funds [e]	182.1	35.0	147.1	—
U.S. Treasury	4.5	4.5	—	—
U.S. Agency, state and local obligations	19.6	—	19.6	—
U.S. corporate bonds [f]	28.9	—	28.9	—
Foreign corporate bonds	2.6	—	2.6	—
Hedge funds [g]	21.6	—	—	21.6
Total	$ 660.8	$ 145.8	$ 455.0	$ 60.0
Cash equivalents	5.6			
Total Pension Plans	$ 666.4			

[a] At December 31, 2013 and 2012, this category is comprised of $80.5 million and $69.7 million, respectively, of traded mutual funds valued at daily listed prices and $113.2 million and $99.9 million, respectively, of institutional common/collective trust funds valued at Net Asset Value (NAV) per share.

[b] At December 31, 2013 and 2012, this category is comprised of $39.9 million and $36.6 million, respectively, of traded mutual funds valued at daily listed prices and $127.2 million and $114.6 million, respectively, of institutional common/collective trust funds valued at daily NAV per share.

[c] This category is comprised of institutional common/collective trust funds and a limited partnership valued at NAV on a quarterly basis.

[d] This category is comprised of institutional common/collective trust funds valued at daily NAV per share.

[e] At December 31, 2013 and 2012, this category is comprised of $27.1 million and $35.0 million, respectively, of traded mutual funds valued at daily listed prices and $154.2 million and $147.1 million, respectively, of institutional common/collective trust funds valued at daily NAV per share.

[f] At December 31, 2013 and 2012, this category is comprised of $20.1 million and $21.5 million, respectively, of corporate bonds, $3.6 million and $5.2 million, respectively, of collateralized mortgage obligations and $1.9 million and $2.2 million, respectively, of other asset-backed securities.

[g] This category is comprised of closely-held limited partnerships valued at NAV on a quarterly basis.

The following tables reconcile the beginning and ending balances for all level 3 pension plan assets measured at fair value on a recurring basis for 2013 and 2012.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)

Description	Real Estate	Hedge Funds	Total
		(millions)	
Balance January 1, 2013	$ 38.4	$ 21.6	$ 60.0
Actual return on plan assets			
Relating to assets still held	4.6	1.5	6.1
Purchase, sales and settlements	0.7	—	0.7
Balance December 31, 2013	$ 43.7	$ 23.1	$ 66.8

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)			
Description	**Real Estate**	**Hedge Funds**	**Total**
		(millions)	
Balance January 1, 2012	$ 34.7	$ 21.7	$ 56.4
Actual return on plan assets			
Relating to assets still held	1.6	0.6	2.2
Relating to assets sold	1.3	(0.4)	0.9
Purchase, sales and settlements	0.8	(0.3)	0.5
Balance December 31, 2012	$ 38.4	$ 21.6	$ 60.0

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, 2013 and 2012, by asset category are in the following tables.

		Fair Value Measurements Using		
Description	**December 31 2013**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		(millions)		
Other Post-Retirement Benefit Plans				
Equity securities	$ 2.2	$ 2.2	$ —	$ —
Fixed income securities				
Fixed income fund [a]	74.6	0.2	74.4	—
U.S. Treasury	1.5	1.5	—	—
U.S. Agency, state and local obligations	4.4	—	4.4	—
U.S. corporate bonds [b]	8.6	—	8.6	—
Foreign corporate bonds	1.0	—	1.0	—
Cash equivalents	8.6	8.6	—	—
Other	0.3	—	0.3	—
Total	$ 101.2	$ 12.5	$ 88.7	$ —

Description	December 31 2012	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)
		(millions)		
Other Post-Retirement Benefit Plans				
Equity securities	$ 1.7	$ 1.7	$ —	$ —
Fixed income securities				
U.S. Treasury	13.7	13.7	—	—
U.S. Agency, state and local obligations	28.6	—	28.6	—
U.S. corporate bonds [b]	20.1	—	20.1	—
Foreign corporate bonds	2.2	—	2.2	—
Mutual funds	0.2	0.2	—	—
Total	$ 66.5	$ 15.6	$ 50.9	$ —
Cash equivalents	23.8			
Total Other Post-Retirement Benefit Plans	$ 90.3			

[a] This category is comprised of $74.4 million of an institutional common/collective trust fund valued at daily NAV per share and $0.2 million of traded mutual funds valued at daily listed prices.

[b] At December 31, 2013 and 2012, this category is comprised of $7.1 million and $17.1 million, respectively, of corporate bonds, $0.3 million and $1.4 million, respectively, of collateralized mortgage obligations and $1.2 million and $1.6 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 trends assumed for 2013 and 2014 were 7.5% and 7.0%, respectively, with the rate declining through 2018 to the ultimate cost trend rate of 5%. The health care plan requires retirees to make monthly contributions on behalf of themselves and their dependents in an amount determined by Great Plains Energy.

The effects of a one-percentage point change in the assumed health care cost trend rates, holding all other assumptions constant, at December 31, 2013, are detailed in the following table.

	Increase	Decrease
	(millions)	
Effect on total service and interest component	$ 1.1	$ (1.0)
Effect on post-retirement benefit obligation	8.8	(7.3)

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 $9.6 million in 2013 and $9.2 million in 2012 and 2011. KCP&L's annual cost of the plans was approximately $7.0 million in 2013 and $6.7 million in 2012 and 2011.

Voluntary Separation Program

In 2011, Great Plains Energy executed an organizational realignment and voluntary separation program to assist in the management of overall costs within the level reflected in the Company's retail electric rates and to enhance organizational efficiency. Great Plains Energy and KCP&L recorded expense of $12.7 million and $9.2 million, respectively, in 2011 related to this voluntary separation program reflecting severance and related payroll taxes provided to employees who elected to voluntarily separate from the Company. In 2012, KCP&L deferred $4.3 million of expense related to the voluntary separation program to a regulatory asset for recovery in rates beginning January 1, 2013, pursuant to KCP&L's December 2012 KCC rate order.

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 2014 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.

	2013	2012	2011
Great Plains Energy		(millions)	
Equity compensation expense	$ 5.6	$ 3.3	$ 5.2
Income tax benefit	1.9	1.4	1.9
KCP&L			
Equity compensation expense	$ 4.0	$ 2.3	$ 3.5
Income tax benefit	1.3	1.0	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 2013, inputs for expected volatility, dividend yield and risk-free rates were 19%, 3.88%, and 0.35%, 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, 2013	370,560	$ 23.05
Granted	226,967	24.17
Earned	(104,453)	23.37
Forfeited	(11,523)	22.82
Performance adjustment	(51,542)	23.37
Ending balance December 31, 2013	430,009	23.52

* weighted-average

At December 31, 2013, the remaining weighted-average contractual term was 1.3 years. The weighted-average grant-date fair value of shares granted was $24.17, $19.37 and $26.15 in 2013, 2012 and 2011, respectively. At December 31, 2013, there was $5.7 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 in 2013 was $2.4 million. There were no performance shares earned and paid in 2012. The total fair value of performance shares earned and paid in 2011 was $0.8 million.

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, 2013	277,439	$ 19.03
Granted and issued	79,645	22.47
Vested	(64,405)	17.88
Forfeited	(4,142)	21.44
Ending balance December 31, 2013	288,537	20.18

* weighted-average

At December 31, 2013, the remaining weighted-average contractual term was 1.2 years. The weighted-average grant-date fair value of shares granted was $22.47, $19.75 and $19.03 in 2013, 2012 and 2011, respectively. At December 31, 2013, there was $2.2 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. The total fair value of shares vested was $1.2 million, $3.3 million and $2.6 million in 2013, 2012 and 2011, 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 until 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 2013 and 2012. Director Deferred Share Units activity is summarized in the following table.

	Share Units	Grant Date Fair Value*
Beginning balance January 1, 2013	69,818	$ 20.36
Issued	20,302	22.95
Ending balance December 31, 2013	90,120	20.94

* 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 2018. 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, 2013, Great Plains Energy was in compliance with this covenant. At December 31, 2013, Great Plains Energy had $9.0 million of outstanding cash borrowings at a weighted-average interest rate of 1.94% and had issued no letters of credit under the credit facility. At December 31, 2012, Great Plains Energy had $12.0 million of outstanding cash borrowings at a weighted-average interest rate of 2.00% and had issued letters of credit totaling $1.8 million 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 2018. 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, 2013, KCP&L was in compliance with this covenant. At December 31, 2013, KCP&L had $93.2 million of commercial paper outstanding at a weighted-average interest rate of 0.29%, had issued letters of credit totaling $3.8 million and had no outstanding cash borrowings under the credit facility. At December 31, 2012, KCP&L had $361.0 million of commercial paper outstanding at a weighted-average interest rate of 0.48%, had issued letters of credit totaling $13.9 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 2018. 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, 2013, GMO was in compliance with this covenant. At December 31, 2013, GMO had $15.0 million of commercial paper outstanding at a weighted-average interest rate of 0.66%, had issued letters of credit totaling $16.4 million and had no outstanding cash borrowings under the credit facility. At December 31, 2012, GMO had $169.1 million of commercial paper outstanding at a weighted-average interest rate of 0.94%, had issued letters of credit totaling $15.1 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 2013	December 31 2012
KCP&L		(millions)	
General Mortgage Bonds			
2.95% EIRR bonds[a]	2015-2035	$ 146.4	$ 106.9
7.15% Series 2009A (8.59% rate)[b]	2019	400.0	400.0
4.65% EIRR Series 2005	2035	50.0	50.0
5.375% Series 2007B		—	73.2
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	—
6.05% Series (5.78% rate)[b]	2035	250.0	250.0
5.30% Series	2041	400.0	400.0
EIRR Bonds			
0.07% Series 2007A and 2007B[c]	2035	146.5	—
2.875% Series 2008	2038	23.4	23.4
Other		—	2.6
Current maturities		—	(0.4)
Unamortized discount		(4.1)	(4.0)
Total KCP&L excluding current maturities		2,312.2	1,901.7
Other Great Plains Energy			
GMO First Mortgage Bonds 9.44% Series	2014-2021	9.0	10.1
GMO Pollution Control Bonds			
0.113% Wamego Series 1996[c]	2026	7.3	7.3
0.113% State Environmental 1993[c]	2028	5.0	5.0
5.85% SJLP Pollution Control		—	5.6
GMO Senior Notes			
8.27% Series	2021	80.9	80.9
3.49% Series A	2025	125.0	—
4.06% Series B	2033	75.0	—
4.74% Series C	2043	150.0	—
GMO Medium Term Notes			
7.33% Series	2023	3.0	3.0
7.17% Series	2023	7.0	7.0
7.16% Series		—	6.0
Great Plains Energy Senior Notes			
6.875% Series (7.33% rate)[b]	2017	100.0	100.0
4.85% Series (7.34% rate)[b]	2021	350.0	350.0
5.292% Series	2022	287.5	287.5
2.75% Series (3.67% rate)[b]		—	250.0
Current maturities		(1.1)	(262.7)
Unamortized discount and premium, net		4.9	5.4
Total Great Plains Energy excluding current maturities		$ 3,515.7	$ 2,756.8

(a) Weighted-average interest rates at December 31, 2013
(b) Rate after amortizing gains/losses recognized in OCI on settlements of interest rate hedging instruments
(c) Variable rate

Amortization of Debt Expense

Great Plains Energy's and KCP&L's amortization of debt expense is detailed in the following table.

	2013	2012	2011
		(millions)	
KCP&L	$ 3.2	$ 2.9	$ 3.6
Other Great Plains Energy	2.5	2.6	4.5
Total Great Plains Energy	$ 5.7	$ 5.5	$ 8.1

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 $596.4 million and $630.1 million were outstanding at December 31, 2013 and 2012, respectively.

KCP&L Municipal Bond Insurance Policies

KCP&L's secured and unsecured Series 2005 Environmental Improvement Revenue Refunding (EIRR) bonds totaling $35.9 million and $50.0 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, 2013, 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 March 2013, KCP&L issued, at a discount, $300.0 million of 3.15% unsecured Senior Notes, maturing in 2023.

EIRR Bond Remarketing

In April 2013, KCP&L remarketed the following series of EIRR bonds:

- secured Series 1992 EIRR bonds maturing in 2017 totaling $31.0 million at a fixed rate of 1.25% through maturity;
- secured Series 1993B EIRR bonds totaling $39.5 million and previously held by KCP&L and 1993A EIRR bonds totaling $40.0 million maturing in 2023 at a fixed rate of 2.95% through maturity;
- unsecured Series 2007A-1 and 2007A-2 EIRR bonds totaling $10.0 million and $63.3 million, respectively, maturing in 2035 and previously held by KCP&L into one series: Series 2007A totaling $73.3 million at a variable rate that will be determined weekly; and
- unsecured Series 2007B EIRR bonds maturing in 2035 totaling $73.2 million at a variable rate that will be determined weekly.

In July 2013, KCP&L remarketed its unsecured Series 2008 EIRR bonds maturing in 2038 totaling $23.4 million at a fixed rate of 2.875% through July 1, 2018.

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 $9.0 million and $10.1 million, respectively, were outstanding at December 31, 2013 and 2012.

GMO Pollution Control Bonds

In February 2013, GMO repaid its $5.6 million 5.85% SJLP Pollution Control bonds at maturity. In January 2014, GMO made an early repayment of its $7.3 million Wamego Series 1996 and $5.0 million State Environmental 1993 tax-exempt bonds.

GMO Senior Notes

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.

Under the terms of the note purchase agreement, 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, 2013, GMO was in compliance with these covenants.

GMO Medium Term Notes

In November 2013, GMO repaid its $6.0 million 7.16% Medium Term Notes at maturity.

Great Plains Energy Senior Notes

In August 2013, Great Plains Energy repaid its $250.0 million 2.75% Senior Notes at maturity.

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.

	2014	2015	2016	2017	2018
			(millions)		
Great Plains Energy	$ 1.1	$ 15.1	$ 1.1	$ 382.1	$ 351.1
KCP&L	—	14.0	—	281.0	350.0

12. ASSETS HELD FOR SALE

At December 31, 2013, Great Plains Energy and KCP&L had $36.2 million and $4.7 million, respectively, of assets held for sale related to the construction of two Southwest Power Pool, Inc. (SPP)-approved regional transmission projects, consisting of an approximately 30-mile, 345kV transmission line from KCP&L's and GMO's Iatan generating station to KCP&L's Nashua substation and the Missouri portion of an approximately 180-mile, 345kV transmission line from Sibley, Missouri to Nebraska City, Nebraska. In December 2013, FERC accepted the SPP's approval of the novation of these transmission projects to Transource Missouri, LLC (Transource Missouri), a wholly owned subsidiary of Transource. The sale of the assets, at cost, to Transource Missouri was completed in January 2014, resulting in no gain or loss on the sale.

13. COMMON SHAREHOLDERS' EQUITY

Great Plains Energy has an effective shelf registration statement for the sale of unspecified amounts of securities with the Securities and Exchange Commission (SEC) that became effective in March 2012.

Great Plains Energy has 6.0 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, 2013, 1.4 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. Shares issued under the plan may be either newly issued shares or shares purchased in the open market. At December 31, 2013, 1.6 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.

As of December 31, 2013, 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, 2013. The restrictions are not expected to affect the Companies' ability to pay dividends at the current level in the foreseeable future.

14. PREFERRED STOCK

At December 31, 2013, 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.

15. 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 estimate of capital expenditures (exclusive of AFUDC and property taxes) to comply with current final environmental regulations where the timing is certain is approximately $700 million. The total cost of compliance with any existing, proposed or future laws and regulations may be significantly different from the cost estimate provided.

The current estimate of approximately $700 million of capital expenditures reflects costs to install environmental equipment at KCP&L's La Cygne Nos. 1 and 2 by June 2015 to comply with the Best Available Retrofit Technology (BART) rule and environmental upgrades at other coal-fired generating units through 2016 to comply with the Mercury and Air Toxics Standards (MATS) rule.

In September 2011, KCP&L commenced construction of the La Cygne projects and at December 31, 2013, had incurred approximately $377 million of cash capital expenditures, which is included in the approximate $700 million estimate above.

Great Plains Energy and KCP&L estimate that other capital projects at coal-fired generating units for compliance with the Clean Air Act and Clean Water Act based on proposed regulations or final regulations with implementation plans not yet finalized where the timing is uncertain could be approximately $600 million to $800 million for Great Plains Energy, which includes approximately $350 million to $450 million for KCP&L. These other projects are not included in the approximately $700 million estimated cost of compliance discussed above.

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 and associated regulations enacted by the Environmental Protection Agency (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.

Clean Air Interstate Rule (CAIR) and Cross-State Air Pollution Rule (CSAPR)

The CAIR requires reductions in SO_2 and NO_x emissions in 28 states, including Missouri, accomplished through statewide caps. Great Plains Energy's and KCP&L's fossil fuel-fired plants located in Missouri are subject to CAIR, while their fossil fuel-fired plants in Kansas are not.

In July 2008, the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit Court) vacated CAIR in its entirety and remanded the matter to the EPA to promulgate a new rule consistent with its opinion. In December 2008, the court issued an order reinstating CAIR pending EPA's development of a replacement regulation on remand. In July 2011, the EPA finalized the CSAPR to replace the currently-effective CAIR. The CSAPR required states within its scope to reduce power plant SO_2 and NO_x emissions that contribute to ozone and fine particle nonattainment in other states. In August 2012, the D.C. Circuit Court issued its opinion in which it vacated the CSAPR and remanded the rule to the EPA to revise in accordance with its opinion. The D.C. Circuit Court directed the EPA to continue to administer the CAIR until a valid replacement is promulgated.

Best Available Retrofit Technology (BART) Rule

The EPA BART rule directs state air quality agencies to identify whether visibility-reducing emissions from sources subject to BART are below limits set by the state or whether retrofit measures are needed to reduce emissions. BART applies to specific eligible facilities including KCP&L's La Cygne Nos. 1 and 2 in Kansas; KCP&L's Iatan No. 1, in which GMO has an 18% interest, and KCP&L's Montrose No. 3 in Missouri; GMO's Sibley Unit No. 3 and Lake Road Unit No. 6 in Missouri; and Westar Energy, Inc.'s (Westar) Jeffrey Unit Nos. 1 and 2 in Kansas, in which GMO has an 8% interest. Both Missouri and Kansas have approved BART plans.

KCP&L has a consent agreement with the Kansas Department of Health and Environment (KDHE) incorporating limits for stack particulate matter emissions, as well as limits for NO_x and SO_2 emissions, at its La Cygne Station that will be below the presumptive limits under BART. KCP&L further agreed to use its best efforts to install emission control technologies to reduce those emissions from the La Cygne Station prior to the required compliance date under BART, but in no event later than June 1, 2015. In August 2011, KCC issued its order on KCP&L's predetermination request that would apply to the recovery of costs for its 50% share of the environmental equipment required to comply with BART at the La Cygne Station. In the order, KCC stated that KCP&L's decision to retrofit La Cygne was reasonable, reliable, efficient and prudent and the $1.23 billion cost estimate is reasonable. If the cost for the project is at or below the $1.23 billion estimate, absent a showing of fraud or other intentional imprudence, KCC stated that it will not re-evaluate the prudency of the cost of the project. If the cost of the project exceeds the $1.23 billion estimate and KCP&L seeks to recover amounts exceeding the estimate, KCP&L will bear the burden of proving that any additional costs were prudently incurred. KCP&L's 50% share of the estimated cost is $615 million. KCP&L began the project in September 2011.

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. Compliance with the rule would need to be achieved by installing additional emission control equipment, changes in plant operation, purchasing additional power in the wholesale market or a combination of these and other alternatives. The rule allows three to four years for compliance.

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. The rule allows three to four years for compliance.

New Source Review
The Clean Air Act's New Source Review program requires companies to obtain permits and, if necessary, install control equipment to reduce emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in regulated emissions.

In 2010, Westar settled a lawsuit filed by the Department of Justice on behalf of the EPA and agreed to install a selective catalytic reduction (SCR) system at one of the three Jeffrey Energy Center units by the end of 2014. The Jeffrey Energy Center is 92% owned by Westar and operated exclusively by Westar. GMO has an 8% interest in the Jeffrey Energy Center and is generally responsible for its 8% share of the facility's operating costs and capital expenditures. Westar has estimated the cost of this SCR at approximately $240 million. Depending on the NO_x emission reductions attained by that SCR and attainable through the installation of other controls at the other two units, the settlement agreement may require the installation of a second SCR system on one of the other two units. Westar has informed the EPA that they believe that the terms of the settlement can be met through the installation of less expensive NO_x reduction equipment rather than a second SCR system and they plan to complete this project in 2014. GMO expects to seek recovery of its share of these costs through rate increases; however, there can be no assurance that such rate increases would be granted.

SO_2 NAAQS
In June 2010, the EPA strengthened the primary National Ambient Air Quality Standard (NAAQS) for SO_2 by establishing a new 1-hour standard at a level of 0.075 ppm and revoking the two existing primary standards of 0.140 ppm evaluated over 24 hours and 0.030 ppm evaluated over an entire year. In July 2013, the EPA designated a part of Jackson County, Missouri, which is in the Companies' service territory, as a nonattainment area for the new 1-hour SO_2 standard. The Missouri Department of Natural Resources (MDNR) will now develop and submit their plan to the EPA to return the area to attainment of the standard, which may include stricter controls on certain industrial facilities.

Particulate Matter (PM) NAAQS
In December 2012, the EPA strengthened the annual primary NAAQS for fine particulate matter (PM2.5). With the final rule, the EPA provided recent ambient air monitoring data for the Kansas City area indicating it would be in attainment of the revised fine particle standard. States will now make recommendations to designate areas as meeting the standards or not meeting them with the EPA making the final designation.

Climate Change
The Companies are subject to existing greenhouse gas reporting regulations and certain greenhouse gas permitting requirements. 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, while the United States is not a current party to the international Kyoto Protocol, it has agreed to undertake certain voluntary actions under the non-binding Copenhagen Accord and pursuant to subsequent international discussions relating to climate change, including the establishment of a goal to reduce greenhouse gas emissions. International agreements legally binding on the United States may be reached in the future. Such new laws or regulations could mandate new or increased requirements to control or reduce the emission of greenhouse gases, such as CO_2, which are created in the combustion of fossil fuels. The Companies' current generation capacity is primarily coal-fired and is estimated to produce about one ton of CO_2 per MWh, or approximately 25 million tons and 18 million tons per year for Great Plains Energy and KCP&L, respectively.

Legislation concerning the reduction of emissions of greenhouse gases, including CO_2, is being considered at the federal and state levels. The timing and effects of any such legislation cannot be determined at this time. In the absence of new Congressional mandates, the EPA is proceeding with the regulation of greenhouse gases under the existing Clean Air Act.

In June 2013, United States President Barack Obama announced a climate action plan and issued a presidential memorandum to address one element of the plan which is to reduce power plant carbon pollution. The memorandum directs the EPA to:

(1) issue a proposed and final rule addressing new units in a timely fashion;

(2) issue proposed carbon pollution standards, regulations or guidelines, as appropriate, for modified, reconstructed and existing power plants by no later than June 1, 2014;

(3) issue final standards, regulations or guidelines, as appropriate, for modified, reconstructed and existing power plants by no later than June 1, 2015;

(4) include in the guidelines addressing existing power plants a requirement that states submit to the EPA the implementation plans by no later than June 30, 2016; and

(5) engage with states, leaders in the power sector and other stakeholders on issues related to the rules.

In September 2013, the EPA proposed new source performance standards for emissions of CO_2 for new affected fossil-fuel-fired electric utility generating units. This action pursuant to the Clean Air Act would, for the first time, set national limits on the amount of CO_2 that power plants built in the future can emit. The proposal would not apply to Great Plains Energy's and KCP&L's existing units including modifications to those units.

Greenhouse gas legislation or regulation has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L, including the potential costs and impacts of achieving compliance with limits that may be established. However, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until such legislation is passed and/or regulations are issued. Management will continue to monitor the progress of relevant legislation and regulations.

Laws have been passed in Missouri and Kansas, the states in which the Companies' retail electric businesses are operated, setting renewable energy standards, and management believes that national clean or renewable energy standards are also possible. While management believes additional requirements addressing these matters will possibly be enacted, the timing, provisions and impact of such requirements, including the cost to obtain and install new equipment to achieve compliance, cannot be reasonably estimated at this time.

A Kansas law enacted in May 2009 required Kansas public electric utilities, including KCP&L, to have renewable energy generation capacity equal to at least 10% of their three-year average Kansas peak retail demand by 2011 increasing to 15% by 2016 and 20% by 2020. A Missouri law enacted in November 2008 required at least 2% of the electricity provided by Missouri investor-owned utilities (including KCP&L and GMO) to their Missouri retail customers to come from renewable resources, including wind, solar, biomass and hydropower, by 2011, increasing to 5% in 2014, 10% in 2018, and 15% in 2021, with a small portion (estimated to be about 2 MW for each of KCP&L and GMO) required to come from solar resources.

KCP&L and GMO project that they will be compliant with the Missouri renewable requirements, exclusive of the solar requirement, through 2035. KCP&L and GMO project that the acquisition of solar renewable energy credits will be sufficient for compliance with the Missouri solar requirements for the foreseeable future. KCP&L also projects that it will be compliant with the Kansas renewable requirements through 2023.

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 March 2011, the EPA proposed 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 would be subject to a limit on how many fish can be killed by being pinned against intake screens (impingement) and would be required to conduct studies to determine whether and what site-specific controls, if any, would be required to reduce the number of aquatic organisms drawn into cooling water systems (entrainment). The EPA agreed to finalize the rule by April 2014. Although the impact on Great Plains Energy's and KCP&L's operations will not be known until after the rule is finalized, it could have a significant effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

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. KCP&L cannot predict the outcome of this matter; however, while less significant outcomes are possible, this matter may require KCP&L to reduce its generation at Hawthorn Station, install cooling towers or both, any of which could have a significant impact on KCP&L's results of operations, financial position and cash flows. The outcome could also affect the terms of water permit renewals at KCP&L's Iatan Station and at GMO's Sibley and Lake Road Stations.

In April 2013, the EPA proposed to revise the technology-based effluent limitations guidelines and standards regulation to make the existing controls on discharges from steam electric power plants more stringent. The proposal 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 2017 and 2022. The EPA is under a consent decree to take final action on the proposed rule by May 2014.

The proposal includes a variety of options to reduce pollutants that are discharged into waterways from coal ash, air pollution control waste and other waste from steam electric power plants. Depending on the option, the proposed rule would establish 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, combustion residual leachate from landfills and surface impoundments, and non-chemical metal cleaning wastes.

The EPA also announced its intention to align this proposal with a related rule for coal combustion residuals (CCRs) proposed in May 2010 under the Resource Conservation and Recovery Act (RCRA). The EPA is considering establishing best management practices requirements that would apply to surface impoundments containing CCRs. The cost of complying with the proposed rules has the potential of having a significant financial and operational impact on Great Plains Energy and KCP&L. However, the financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until the final regulation is enacted.

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 May 2010, the EPA proposed to regulate CCRs under the RCRA to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The EPA is considering two options in this proposal. Under the first option, the EPA would regulate CCRs as special wastes under subtitle C of RCRA (hazardous), when they are destined for disposal in landfills or surface impoundments. Under the second option, the EPA would regulate disposal of CCRs under subtitle D of RCRA (non-hazardous). The Companies use coal in generating electricity and dispose of the CCRs in both on-site facilities and facilities owned by third parties. The cost of complying with the proposed CCR rule has the potential of having a significant financial and operational impact on Great Plains Energy and KCP&L. However, the financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until an option is selected by the EPA and the final regulation is enacted.

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, 2013 and 2012, 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, 2013 and 2012, Great Plains Energy had $1.4 million and $2.0 million, respectively, 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 $1.3 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.

	2013	2012	2011
		(millions)	
Great Plains Energy	$ 18.5	$ 21.8	$ 20.9
KCP&L	16.0	17.7	17.0

Great Plains Energy's and KCP&L's contractual commitments at December 31, 2013, excluding pensions and long-term debt, are detailed in the following tables.

Great Plains Energy

	2014	2015	2016	2017	2018	After 2018	Total
Lease commitments				(millions)			
Operating lease	$ 15.3	$ 13.6	$ 10.0	$ 9.7	$ 9.7	$ 138.6	$ 196.9
Capital lease	0.4	0.4	0.4	0.4	0.4	4.4	6.4
Purchase commitments							
Fuel	381.8	195.0	143.8	142.8	117.2	90.2	1,070.8
Power	46.4	46.4	46.4	44.8	47.3	604.1	835.4
Capacity	3.3	3.0	1.2	—	—	—	7.5
La Cygne environmental project	205.5	7.3	—	—	—	—	212.8
Non-regulated natural gas transportation	3.5	3.5	3.5	1.0	—	—	11.5
Other	56.2	36.8	27.5	8.1	3.9	46.6	179.1
Total contractual commitments	$ 712.4	$ 306.0	$ 232.8	$ 206.8	$ 178.5	$ 883.9	$ 2,520.4

KCP&L

	2014	2015	2016	2017	2018	After 2018	Total
Lease commitments				(millions)			
Operating lease	$ 13.5	$ 12.2	$ 9.9	$ 9.7	$ 9.7	$ 138.6	$ 193.6
Capital lease	0.2	0.2	0.2	0.2	0.2	2.2	3.2
Purchase commitments							
Fuel	294.3	148.4	113.2	117.4	90.8	90.2	854.3
Power	34.8	34.8	34.8	34.8	34.8	429.4	603.4
Capacity	2.9	3.0	1.2	—	—	—	7.1
La Cygne environmental project	205.5	7.3	—	—	—	—	212.8
Other	54.0	27.1	26.7	7.2	3.0	38.1	156.1
Total contractual commitments	$ 605.2	$ 233.0	$ 186.0	$ 169.3	$ 138.5	$ 698.5	$ 2,030.5

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 $2.0 million per year from 2014 to 2015 and approximately $0.4 million per year from 2016 to 2025, for a total of $8.2 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 $5.5 million from 2014 to 2016 and $1.3 million per year for 2017 and 2018. La Cygne environmental project represents 100% of the contractual commitments related to environmental upgrades at KCP&L's La Cygne Station. KCP&L owns 50% of the La Cygne Station and expects to be reimbursed by the other owner for its 50% share of the costs. Non-regulated natural gas transportation consists of MPS Merchant's commitments. Other represents individual commitments entered into in the ordinary course of business.

16. LEGAL PROCEEDINGS

GMO Western Energy Crisis

In response to complaints of manipulation of the California energy market, The Federal Energy Regulatory Commission (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. 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 the July 2001 FERC order 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 did not provide a sufficient justification for refusing to exercise its remedial authority under the Federal Power Act to determine whether market participants violated FERC-approved tariffs during the Summer Period. The court remanded the matter to FERC for further consideration. If FERC determines that MPS Merchant violated then-existing tariffs or laws during the Summer Period and that such violations affected market clearing prices in California, MPS Merchant could be found to owe refunds. Due to the uncertainties remaining in the case, the potential refund or range of potential refunds owed by MPS Merchant are not reasonably estimable.

17. 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, 2013, Great Plains Energy has provided $140.6 million of credit support for GMO as follows:

- Great Plains Energy direct guarantees to GMO counterparties totaling $40.7 million, which expire in 2014 and 2015 and
- Great Plains Energy guarantee of GMO long-term debt totaling $99.9 million, which includes debt with maturity dates ranging from 2014-2023.

Great Plains Energy has also guaranteed GMO's commercial paper program. At December 31, 2013, GMO had $15.0 million of commercial paper outstanding.

18. 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 $223.6 million for 2013, $207.9 million for 2012 and $202.7 million for 2011. Additionally, KCP&L and GMO engage in wholesale electricity transactions with each other. KCP&L's net wholesale sales to GMO were $25.6 million, $29.4 million and $18.2 million in 2013, 2012 and 2011, 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, 2013, KCP&L had a money pool payable to GMO of $0.2 million. At December 31, 2012, KCP&L had a money pool payable to Great Plains Energy of $3.8 million. The following table summarizes KCP&L's related party net receivables.

	December 31	
	2013	2012
	(millions)	
Net receivable from GMO	$ 32.7	$ 26.2
Net receivable from Great Plains Energy	17.5	13.8

19. 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 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 recognized currently in net income unless specific hedge accounting criteria are met, except hedges for GMO's utility operations that are recorded to a regulatory asset or liability consistent with MPSC regulatory orders, as discussed below.

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, 2013, 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 all receivables and payables with each respective counterparty.

Commodity Risk Management

KCP&L's risk management policy is to use derivative instruments, as needed, in order to mitigate its exposure to market price fluctuations on a portion of its projected natural gas purchases to meet generation requirements for retail and firm wholesale sales. KCP&L designates these natural gas hedges as cash flow hedges. The fair values of these instruments are recorded as derivative assets or liabilities with an offsetting entry to OCI for the effective portion of the hedge. To the extent the hedges are not effective, any ineffective portion of the change in fair market value would be recorded currently in fuel expense. At December 31, 2013, KCP&L had no hedges for its projected natural gas usage for retail load and firm MWh sales. KCP&L has not recorded any ineffectiveness on natural gas hedges in 2013, 2012 or 2011.

Additionally, KCP&L's risk management policy uses derivative instruments to mitigate exposure to market price fluctuations for wholesale power prices. 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 to the consolidated statements of income.

KCP&L and GMO have Transmission Congestion Rights (TCR) that were acquired in the initial auction for the SPP Integrated Marketplace during the fourth quarter of 2013. KCP&L and GMO will utilize the TCRs to hedge against congestion costs and protect load prices when the SPP Integrated Marketplace begins operations in March 2014. These financial contracts have been designated as economic hedges (non-hedging derivatives). The fair value of these instruments are recorded as derivative assets or liabilities with an offsetting entry to the consolidated statements of income. At December 31, 2013, there was no change in the fair value since the initial SPP Integrated Marketplace auction.

GMO's risk management policy is to use derivative instruments to mitigate price exposure to natural gas price volatility in the market. At December 31, 2013, GMO had financial contracts in place to hedge approximately 40% and 6% of the expected on-peak natural gas generation and natural gas equivalent purchased power price exposure for 2014 and 2015, 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 FAC. 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 income.

The notional 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			
	2013		2012	
	Notional Contract Amount	Fair Value	Notional Contract Amount	Fair Value
Great Plains Energy	(millions)			
Futures contracts				
Cash flow hedges	$ —	$ —	$ 1.0	$ (0.2)
Non-hedging derivatives	19.3	(0.6)	17.9	(2.8)
Forward contracts				
Non-hedging derivatives	47.7	5.2	65.5	6.5
Transmission congestion rights				
Non-hedging derivatives	22.9	1.7	—	—
Option contracts				
Non-hedging derivatives	4.8	1.2	—	—
KCP&L				
Futures contracts				
Cash flow hedges	$ —	$ —	$ 1.0	$ (0.2)
Non-hedging derivatives	7.7	(0.2)	—	—
Transmission congestion rights				
Non-hedging derivatives	18.0	1.1	—	—

The fair values of Great Plains Energy's and KCP&L's open derivative positions are summarized in the following tables. The tables contain both derivative instruments designated as hedging instruments as well as non-hedging derivatives under GAAP. The fair values below are gross values before netting agreements and netting of cash collateral.

Great Plains Energy

December 31, 2013	Balance Sheet Classification	Asset Derivatives Fair Value	Liability Derivatives Fair Value
Derivatives Not Designated as Hedging Instruments		(millions)	
Commodity contracts	Other	8.5	1.0
December 31, 2012			
Derivatives Designated as Hedging Instruments			
Commodity contracts	Other	$ —	$ 0.2
Derivatives Not Designated as Hedging Instruments			
Commodity contracts	Other	6.5	2.8
Total Derivatives		$ 6.5	$ 3.0

KCP&L

December 31, 2013	Balance Sheet Classification	Asset Derivatives Fair Value	Liability Derivatives Fair Value
Derivatives Not Designated as Hedging Instruments		(millions)	
Commodity contracts	Other	$ 1.2	$ 0.3
December 31, 2012			
Derivatives Designated as Hedging Instruments			
Commodity contracts	Other	$ —	$ 0.2

The following tables provide information regarding Great Plains Energy's and KCP&L's offsetting of derivative assets and liabilities.

Great Plains Energy

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 Received	Net Amount
December 31, 2013			(millions)			
Derivative assets	$ 8.5	$ (0.7)	$ 7.8	$ —	$ —	$ 7.8
Derivative liabilities	1.0	(0.9)	0.1	—	—	0.1
December 31, 2012						
Derivative assets	$ 6.5	$ —	$ 6.5	$ —	$ —	$ 6.5
Derivative liabilities	3.0	(3.0)	—	—	—	—

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 Received	Net Amount
December 31, 2013			(millions)			
Derivative assets	$ 1.2	$ (0.1)	$ 1.1	$ —	$ —	$ 1.1
Derivative liabilities	0.3	(0.3)	—	—	—	—
December 31, 2012						
Derivative liabilities	$ 0.2	$ (0.2)	$ —	$ —	$ —	$ —

The following tables summarize the amount of gain (loss) recognized in OCI or earnings for interest rate and commodity hedges.

Great Plains Energy

Derivatives in Cash Flow Hedging Relationship

	Amount of Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion): Income Statement Classification	Amount
2013	(millions)		(millions)
Interest rate contracts	$ —	Interest charges	$ (18.6)
Commodity contracts	—	Fuel	(0.3)
Income tax benefit	—	Income tax benefit	7.3
Total	$ —	Total	$ (11.6)
2012			
Interest rate contracts	$ —	Interest charges	$ (20.2)
Commodity contracts	(0.1)	Fuel	(0.5)
Income tax benefit	—	Income tax benefit	8.1
Total	$ (0.1)	Total	$ (12.6)

KCP&L

Derivatives in Cash Flow Hedging Relationship

	Amount of Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	
		Income Statement Classification	Amount
2013	(millions)		(millions)
Interest rate contracts	$ —	Interest charges	$ (8.8)
Commodity contracts	—	Fuel	(0.3)
Income tax benefit	—	Income tax benefit	3.5
Total	$ —	Total	$ (5.6)
2012			
Interest rate contracts	$ —	Interest charges	$ (8.7)
Commodity contracts	(0.1)	Fuel	(0.5)
Income tax benefit	—	Income tax benefit	3.5
Total	$ (0.1)	Total	$ (5.7)

The following table summarizes the amount of loss recognized in a regulatory asset or earnings for GMO utility commodity hedges. GMO utility commodity derivatives fair value changes are recorded to either a regulatory asset or liability consistent with MPSC regulatory orders.

Great Plains Energy

Derivatives in Regulatory Account Relationship

	Amount of Gain (Loss) Recognized in Regulatory Asset on Derivatives	Gain (Loss) Reclassified from Regulatory Account	
		Income Statement Classification	Amount
2013	(millions)		(millions)
Commodity contracts	$ 2.0	Fuel	$ (1.9)
Total	$ 2.0	Total	$ (1.9)
2012			
Commodity contracts	$ (2.7)	Fuel	$ (6.6)
Total	$ (2.7)	Total	$ (6.6)

Great Plains Energy's income statement reflects the gain (loss) for the change in fair value of commodity contract derivatives not designated as hedging instruments of $(0.5) million for 2013 and $1.3 million for 2012. KCP&L's income statement reflects the gain for the change in fair value of commodity contract derivatives not designated as hedging instruments of $0.8 million for 2013.

The amounts recorded in accumulated OCI related to the cash flow hedges are summarized in the following table.

	Great Plains Energy December 31		KCP&L December 31	
	2013	2012	2013	2012
	(millions)			
Current assets	$ 9.9	$ 10.6	$ 9.9	$ 10.6
Current liabilities	(48.9)	(68.4)	(43.1)	(52.8)
Noncurrent liabilities	—	(0.1)	—	(0.1)
Deferred income taxes	15.2	22.5	13.0	16.5
Total	$ (23.8)	$ (35.4)	$ (20.2)	$ (25.8)

Great Plains Energy's accumulated OCI in the table above at December 31, 2013, includes $17.1 million that is expected to be reclassified to expenses over the next twelve months. KCP&L's accumulated OCI in the table above at December 31, 2013, includes $8.7 million that is expected to be reclassified to expenses over the next twelve months.

20. 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, 2013, the book value and fair value of Great Plains Energy's long-term debt, including current maturities, were $3.5 billion and $3.7 billion, respectively. At December 31, 2012, the book value and fair value of Great Plains Energy's long-term debt, including current maturities, were $3.0 billion and $3.5 billion, respectively. At December 31, 2013, the book value and fair value of KCP&L's long-term debt, including current maturities, were $2.3 billion and $2.5 billion, respectively. At December 31, 2012, the book value and fair value of KCP&L's long-term debt, including current maturities, were $1.9 billion and $2.2 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.

Description	December 31 2013	Netting[e]	Level 1	Level 2	Level 3
KCP&L			(millions)		
Assets					
Nuclear decommissioning trust [a]					
Equity securities	$ 127.7	$ —	$ 127.7	$ —	$ —
Debt securities					
U.S. Treasury	21.2	—	21.2	—	—
U.S. Agency	2.8	—	—	2.8	—
State and local obligations	3.9	—	—	3.9	—
Corporate bonds	24.4	—	—	24.4	—
Foreign governments	0.5	—	—	0.5	—
Cash equivalents	3.8	—	3.8	—	—
Other	(0.4)	—	—	(0.4)	—
Total nuclear decommissioning trust	183.9	—	152.7	31.2	—
Self-insured health plan trust [b]					
Equity securities	0.9	—	0.9	—	—
Debt securities	9.3	—	0.5	8.8	—
Cash and cash equivalents	3.4	—	3.4	—	—
Other	1.2	—	—	1.2	—
Total self-insured health plan trust	14.8	—	4.8	10.0	—
Derivative instruments [c]	1.1	(0.1)	0.1	—	1.1
Total	199.8	(0.1)	157.6	41.2	1.1
Liabilities					
Derivative instruments [c]	—	(0.3)	0.3	—	—
Total	$ —	$ (0.3)	$ 0.3	$ —	$ —
Other Great Plains Energy					
Assets					
Derivative instruments [c]	$ 6.7	$ (0.6)	$ 0.2	$ 4.9	$ 2.2
SERP rabbi trusts [d]					
Equity securities	0.1	—	0.1	—	—
Fixed income funds	18.6	—	—	18.6	—
Total SERP rabbi trusts	18.7	—	0.1	18.6	—
Total	25.4	(0.6)	0.3	23.5	2.2
Liabilities					
Derivative instruments [c]	0.1	(0.6)	0.6	0.1	—
Total	$ 0.1	$ (0.6)	$ 0.6	$ 0.1	$ —
Great Plains Energy					
Assets					
Nuclear decommissioning trust [a]	$ 183.9	$ —	$ 152.7	$ 31.2	$ —
Self-insured health plan trust [b]	14.8	—	4.8	10.0	—
Derivative instruments [c]	7.8	(0.7)	0.3	4.9	3.3
SERP rabbi trusts [d]	18.7	—	0.1	18.6	—
Total	225.2	(0.7)	157.9	64.7	3.3
Liabilities					
Derivative instruments [c]	0.1	(0.9)	0.9	0.1	—
Total	$ 0.1	$ (0.9)	$ 0.9	$ 0.1	$ —

Description	December 31 2012	Netting[e]	Level 1	Level 2	Level 3
KCP&L			(millions)		
Assets					
Nuclear decommissioning trust [a]					
Equity securities	$ 100.1	$ —	$ 100.1	$ —	$ —
Debt securities					
U.S. Treasury	18.5	—	18.5	—	—
U.S. Agency	2.8	—	—	2.8	—
State and local obligations	3.3	—	—	3.3	—
Corporate bonds	26.8	—	—	26.8	—
Other	0.3	—	—	0.3	—
Total nuclear decommissioning trust	151.8	—	118.6	33.2	—
Total	151.8	—	118.6	33.2	—
Liabilities					
Derivative instruments [c]	—	(0.2)	0.2	—	—
Total	$ —	$ (0.2)	$ 0.2	$ —	$ —
Other Great Plains Energy					
Assets					
Derivative instruments [c]	$ 6.5	$ —	$ —	$ 4.2	$ 2.3
SERP rabbi trusts [d]					
Equity securities	0.1	—	0.1	—	—
Fixed income funds	20.2	—	—	20.2	—
Total SERP rabbi trusts	20.3	—	0.1	20.2	—
Total	26.8	—	0.1	24.4	2.3
Liabilities					
Derivative instruments [c]	—	(2.8)	2.8	—	—
Total	$ —	$ (2.8)	$ 2.8	$ —	$ —
Great Plains Energy					
Assets					
Nuclear decommissioning trust [a]	$ 151.8	$ —	$ 118.6	$ 33.2	$ —
Derivative instruments [c]	6.5	—	—	4.2	2.3
SERP rabbi trusts [d]	20.3	—	0.1	20.2	—
Total	178.6	—	118.7	57.6	2.3
Liabilities					
Derivative instruments [c]	—	(3.0)	3.0	—	—
Total	$ —	$ (3.0)	$ 3.0	$ —	$ —

(a) Fair value is based on quoted market prices of the investments held by the fund and/or valuation models. The total does not include $2.9 million of cash and cash equivalents at December 31, 2012.

(b) Fair value is based on quoted market prices of the investments held by the trust. Debt securities classified as Level 1 are comprised of U.S. Treasury securities. 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) Fair value is based on quoted market prices and/or valuation models for equity securities and NAV per share for fixed income funds.

(e) Represents the difference between derivative contracts in an asset or liability position presented on a net basis by counterparty on the consolidated balance sheets where a master netting agreement exists between the Company and the counterparty. At December 31, 2013 and 2012, Great Plains Energy netted $0.2 million and $3.0 million, respectively, of cash collateral posted with counterparties.

The following table reconciles the beginning and ending balances for all Level 3 assets measured at fair value on a recurring basis.

Great Plains Energy

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	Derivative Instruments	
	2013	2012
	(millions)	
Balance at January 1	$ 2.3	$ 3.1
Total realized/unrealized gains included in non-operating income	9.5	8.2
Purchases	1.7	—
Settlements	(10.2)	(9.0)
Balance at December 31	$ 3.3	$ 2.3
Total unrealized losses included in non-operating income relating to assets still on the consolidated balance sheet at December 31	$ (0.3)	$ (0.4)

KCP&L

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	Derivative Instruments 2013
	(millions)
Balance at January 1	$ —
Purchases	1.1
Balance at December 31	$ 1.1

21. 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)	
Beginning balance January 1, 2013	$ (35.4)	$ (3.0)	$ (38.4)
Other comprehensive income before reclassifications	—	1.2	1.2
Amounts reclassified from accumulated other comprehensive loss	11.6	0.3	11.9
Net current period other comprehensive income	11.6	1.5	13.1
Ending balance December 31, 2013	$ (23.8)	$ (1.5)	$ (25.3)

[a] Net of tax

KCP&L

	Gains and Losses on Cash Flow Hedges[a]
	(millions)
Beginning balance January 1, 2013	$ (25.8)
Amounts reclassified from accumulated other comprehensive loss	5.6
Net current period other comprehensive income	5.6
Ending balance December 31, 2013	$ (20.2)

[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	Affected Line Item in the Income Statement
2013	(millions)	
Gains and (losses) on cash flow hedges (effective portion)		
Interest rate contracts	$ (18.6)	Interest charges
Commodity contracts	(0.3)	Fuel
	(18.9)	Income before income tax expense and loss from equity investments
	7.3	Income tax benefit
	$ (11.6)	Net income
Amortization of defined benefit pension items		
Net losses included in net periodic benefit costs	$ (0.5)	Utility operating and maintenance expenses
	(0.5)	Income before income tax expense and loss from equity investments
	0.2	Income tax benefit
	(0.3)	Net income
Total reclassifications, net of tax	$ (11.9)	Net income

KCP&L

Details about Accumulated Other Comprehensive Loss Components	Amount Reclassified from Accumulated Other Comprehensive Loss	Affected Line Item in the Income Statement
2013	(millions)	
Gains and (losses) on cash flow hedges (effective portion)		
Interest rate contracts	$ (8.8)	Interest charges
Commodity contracts	(0.3)	Fuel
	(9.1)	Income before income tax expense
	3.5	Income tax benefit
Total reclassifications, net of tax	$ (5.6)	Net income

22. TAXES

Components of income tax expense are detailed in the following tables.

Great Plains Energy	2013	2012	2011
Current income taxes		(millions)	
Federal	$ 0.3	$ (3.2)	$ 2.9
State	(3.0)	(6.3)	(6.0)
Foreign	—	—	(0.4)
Total	(2.7)	(9.5)	(3.5)
Deferred income taxes			
Federal	109.1	96.3	90.5
State	24.9	24.9	20.7
Total	134.0	121.2	111.2
Noncurrent income taxes			
Federal	—	(0.2)	(18.0)
State	(0.3)	(0.3)	(2.1)
Foreign	(0.4)	(4.2)	(0.6)
Total	(0.7)	(4.7)	(20.7)
Investment tax credit			
Deferral	0.3	—	—
Amortization	(1.7)	(2.4)	(2.2)
Total	(1.4)	(2.4)	(2.2)
Income tax expense	$ 129.2	$ 104.6	$ 84.8

KCP&L	2013	2012	2011
Current income taxes		(millions)	
Federal	$ (0.5)	$ 13.1	$ 1.0
State	(0.5)	2.0	(0.6)
Total	(1.0)	15.1	0.4
Deferred income taxes			
Federal	75.8	48.8	66.0
State	16.3	11.4	14.6
Total	92.1	60.2	80.6
Noncurrent income taxes			
Federal	(9.0)	1.7	(9.3)
State	(1.5)	0.1	(1.1)
Total	(10.5)	1.8	(10.4)
Investment tax credit			
Deferral	0.3	—	—
Amortization	(1.1)	(1.8)	(1.5)
Total	(0.8)	(1.8)	(1.5)
Income tax expense	$ 79.8	$ 75.3	$ 69.1

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	2013	2012	2011
Federal statutory income tax rate	35.0%	35.0%	35.0%
Differences between book and tax depreciation not normalized	(0.3)	1.2	1.5
Amortization of investment tax credits	(0.4)	(0.8)	(0.8)
Federal income tax credits	(3.5)	(3.1)	(5.0)
State income taxes	3.8	4.0	4.0
Changes in uncertain tax positions, net	(0.2)	(1.5)	(1.7)
Valuation allowance	—	—	(0.8)
Other	(0.4)	(0.5)	0.5
Effective income tax rate	34.0%	34.3%	32.7%

KCP&L	2013	2012	2011
Federal statutory income tax rate	35.0%	35.0%	35.0%
Differences between book and tax depreciation not normalized	(0.8)	1.3	1.6
Amortization of investment tax credits	(0.4)	(0.8)	(0.7)
Federal income tax credits	(5.3)	(4.3)	(6.3)
State income taxes	3.7	4.1	3.9
Changes in uncertain tax positions, net	—	—	0.1
Other	(0.1)	(0.6)	0.2
Effective income tax rate	32.1%	34.7%	33.8%

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	**2013**	**2012**	**2013**	**2012**
Current deferred income tax asset (liability)	(millions)			
Net operating loss carryforward	$ 76.6	$ 77.8	$ —	$ —
Other	5.7	12.7	(1.7)	4.6
Net current deferred income tax asset (liability) before valuation allowance	82.3	90.5	(1.7)	4.6
Valuation allowance	(2.0)	(2.0)	—	—
Net current deferred income tax asset (liability)	80.3	88.5	(1.7)	4.6
Noncurrent deferred income taxes				
Plant related	(1,433.8)	(1,297.2)	(1,022.9)	(930.7)
Income taxes on future regulatory recoveries	(136.4)	(138.3)	(111.0)	(114.7)
Derivative instruments	32.3	37.7	23.4	27.4
Pension and post-retirement benefits	(28.2)	(26.6)	(1.7)	(3.4)
SO_2 emission allowance sales	28.8	29.7	28.8	30.4
Tax credit carryforwards	229.3	217.5	139.6	126.3
Customer demand programs	(27.7)	(28.7)	(19.4)	(19.2)
Net operating loss carryforward	446.7	439.4	71.6	72.4
Other	(57.1)	(44.1)	(30.5)	(24.9)
Net noncurrent deferred income tax liability before valuation allowance	(946.1)	(810.6)	(922.1)	(836.4)
Valuation allowance	(18.7)	(21.8)	—	—
Net noncurrent deferred income tax liability	(964.8)	(832.4)	(922.1)	(836.4)
Net deferred income tax liability	$ (884.5)	$ (743.9)	$ (923.8)	$ (831.8)

	Great Plains Energy		KCP&L	
December 31	**2013**	**2012**	**2013**	**2012**
	(millions)			
Gross deferred income tax assets	$ 1,148.2	$ 1,209.8	$ 583.0	$ 656.9
Gross deferred income tax liabilities	(2,032.7)	(1,953.7)	(1,506.8)	(1,488.7)
Net deferred income tax liability	$ (884.5)	$ (743.9)	$ (923.8)	$ (831.8)

Tax Credit Carryforwards

At December 31, 2013 and 2012, Great Plains Energy had $141.1 million and $127.6 million, respectively, of federal general business income tax credit carryforwards. At December 31, 2013 and 2012, KCP&L had $139.6 million and $126.3 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 2033. 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, 2013 and 2012, Great Plains Energy had $87.9 million of federal alternative minimum tax credit carryforwards. Of these amounts, $87.6 million, at December 31, 2013 and 2012, were acquired in the GMO acquisition. These credits do not expire and can be used to reduce taxes paid in the future.

At December 31, 2013 and 2012, Great Plains Energy had $0.3 million and $2.0 million, respectively, of state income tax credit carryforwards. The state income tax credits relate primarily to the Company's Missouri affordable housing investment portfolio, and the carryforwards expire in the years 2014 to 2016.

Net Operating Loss Carryforwards

At December 31, 2013 and 2012, Great Plains Energy had $459.9 million and $451.1 million, respectively, of tax benefits related to federal net operating loss (NOL) carryforwards. Approximately $304.6 million and $304.8 million, at December 31, 2013 and 2012, respectively, are tax benefits related to NOLs that were acquired in the GMO acquisition. The tax benefits for NOLs originating in 2003 are $21.5 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, $28.8 million originating in 2009, $14.0 million originating in 2010 and $109.5 million originating in 2011, and $2.6 million originating in 2012. The federal NOL carryforwards expire in years 2023 to 2032.

In addition, Great Plains Energy also had deferred tax benefits of $63.4 million and $66.1 million related to state NOLs as of December 31, 2013 and 2012, respectively. Of these amounts, approximately $44.4 million and $47.9 million at December 31, 2013 and 2012, respectively, were acquired in the GMO acquisition. Management does not expect to utilize $20.3 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 $20.3 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 state tax NOL carryforwards, and tax credit carryforwards. During 2013, $3.1 million of tax benefit was recorded in continuing operations primarily related to state NOL carryforwards offset by an increase in deferred tax expense since a portion of state NOLs expired at December 31, 2013. There was no change to the total valuation allowance in 2012.

Uncertain Tax Positions

At December 31, 2013 and 2012, Great Plains Energy had $9.8 million and $21.4 million, respectively, of liabilities related to unrecognized tax benefits. Of these amounts, $6.5 million and $7.3 million at December 31, 2013 and 2012, respectively, are expected to impact the effective tax rate if recognized. The $11.6 million decrease in unrecognized tax benefits is primarily due to a change in certain income tax accounting methods for the capitalization of assets at KCP&L. This reduction in unrecognized tax benefits is offset by an increase to deferred income tax liabilities since the unrecognized tax benefits were related to temporary tax differences.

At December 31, 2011, Great Plains Energy had $24.0 million of liabilities related to unrecognized tax benefits of which $11.8 million was expected to impact the effective tax rate if recognized. The $2.6 million decrease in unrecognized tax benefits in 2012 is primarily due to a decrease of $4.5 million of unrecognized tax benefits related to former GMO non-regulated operations.

At December 31, 2013 and 2012, KCP&L had none and $10.5 million, respectively, of liabilities related to unrecognized tax benefits. None of these amounts were expected to impact the effective tax rate if recognized. The $10.5 million decrease in unrecognized tax benefits is primarily due to a change in certain income tax accounting methods for the capitalization of assets at KCP&L. This reduction in unrecognized tax benefits is offset by an increase to deferred income tax liabilities since the unrecognized tax benefits were related to temporary tax differences.

At December 31, 2011, KCP&L had $8.7 million of liabilities related to unrecognized tax benefits of which $0.2 million was expected to impact the effective rate if recognized. The $1.8 million increase in unrecognized tax benefits in 2012 was primarily due to an increase of $3.6 million related to temporary tax differences for the current tax year.

The following table reflects activity for Great Plains Energy and KCP&L related to the liability for unrecognized tax benefits.

	Great Plains Energy			KCP&L		
	2013	2012	2011	2013	2012	2011
	(millions)					
Beginning balance January 1	$ 21.4	$ 24.0	$ 42.0	$ 10.5	$ 8.7	$ 19.1
Additions for current year tax positions	—	3.7	1.4	—	3.6	—
Reductions for current year tax positions	(0.3)	—	—	—	—	—
Additions for prior year tax positions	—	—	2.4	—	—	2.3
Reductions for prior year tax positions	(10.5)	(1.8)	(20.9)	(10.5)	(1.6)	(12.6)
Statute expirations	(0.3)	(4.7)	(0.7)	—	(0.2)	(0.1)
Foreign currency translation adjustments	(0.5)	0.2	(0.2)	—	—	—
Ending balance December 31	$ 9.8	$ 21.4	$ 24.0	$ —	$ 10.5	$ 8.7

Great Plains Energy and KCP&L recognize interest related to unrecognized tax benefits in interest expense and penalties in non-operating expenses. At December 31, 2013, 2012 and 2011, amounts accrued for interest related to unrecognized tax benefits for Great Plains Energy were $3.2 million, $3.5 million and $5.7 million, respectively. At December 31, 2013, 2012 and 2011, amounts accrued for penalties with respect to unrecognized tax benefits for Great Plains Energy were $0.6 million, $0.7 million and $1.1 million, respectively. In 2013, 2012 and 2011, Great Plains Energy recognized a decrease of $0.1 million, $2.3 million and $0.9 million, respectively, of interest expense related to unrecognized tax benefits.

At December 31, 2013, 2012 and 2011, amounts accrued for interest related to unrecognized tax benefits for KCP&L were none, $0.1 million and $0.2 million, respectively. At December 31, 2013, 2012 and 2011, amounts accrued for penalties with respect to unrecognized tax benefits for KCP&L were insignificant. In 2013, 2012 and 2011, KCP&L recognized a decrease of $0.1 million, $0.1 million and $1.2 million, respectively, of interest expense related to unrecognized tax benefits.

The IRS is currently auditing Great Plains Energy and its subsidiaries for the 2009 tax year. The Company estimates that it is reasonably possible that $6.9 million of other unrecognized tax benefits for Great Plains Energy may be recognized in the next twelve months due to statute expirations or settlement agreements with tax authorities.

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.

Tangible Property Regulations

In September 2013, the IRS released final regulations regarding amounts paid to acquire, produce or improve tangible property. In addition, proposed regulations were issued regarding the treatment of retirements of depreciable property and general asset accounts. The final regulations are effective for tax years beginning on or after January 1, 2014, for all taxpayers that acquire, produce or improve tangible property. The new regulations have not had a significant impact on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

23. 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 attributable to Great Plains Energy.

The following tables reflect summarized financial information concerning Great Plains Energy's reportable segment.

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	(190.5)	(55.5)	47.6	(198.4)
Income tax (expense) benefit	(135.4)	6.2	—	(129.2)
Net income (loss) attributable to Great Plains Energy	257.1	(6.9)	—	250.2

2012	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,309.9	$ —	$ —	$ 2,309.9
Depreciation and amortization	(272.3)	—	—	(272.3)
Interest charges	(197.3)	(67.3)	43.8	(220.8)
Income tax (expense) benefit	(122.0)	17.4	—	(104.6)
Net income (loss) attributable to Great Plains Energy	216.6	(16.7)	—	199.9

2011	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,318.0	$ —	$ —	$ 2,318.0
Depreciation and amortization	(273.1)	—	—	(273.1)
Interest charges	(176.9)	(67.2)	25.7	(218.4)
Income tax (expense) benefit	(109.3)	24.5	—	(84.8)
Net income (loss) attributable to Great Plains Energy	199.9	(25.5)	—	174.4

	Electric Utility	Other	Eliminations	Great Plains Energy
2013		(millions)		
Assets	$10,019.6	$ 105.6	$ (329.8)	$ 9,795.4
Capital expenditures	669.0	—	—	669.0
2012				
Assets	$ 9,910.6	$ 122.4	$ (385.7)	$ 9,647.3
Capital expenditures	610.2	—	—	610.2
2011				
Assets	$ 9,483.4	$ 51.9	$ (417.3)	$ 9,118.0
Capital expenditures	456.6	—	—	456.6

24. JOINTLY-OWNED ELECTRIC UTILITY PLANTS

Great Plains Energy's and KCP&L's share of jointly-owned electric utility plants at December 31, 2013, 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	$ 1,550.8	$ 542.6	$ 645.3	$ 1,298.0	$ 428.9	$ 165.7
Accumulated depreciation	813.6	314.4	245.7	319.4	87.3	75.4
Nuclear fuel, net	62.8	—	—	—	—	—
Construction work in progress	146.4	390.3	8.1	14.9	24.4	13.8
2014 accredited capacity-MWs	547	709	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	$ 1,550.8	$ 542.6	$ 515.4	$ 987.2	$ 347.3
Accumulated depreciation	813.6	314.4	196.8	297.5	79.3
Nuclear fuel, net	62.8	—	—	—	—
Construction work in progress	146.4	390.3	1.8	11.0	3.5
2014 accredited capacity-MWs	547	709	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.

25. QUARTERLY OPERATING RESULTS (UNAUDITED)

	Quarter			
Great Plains Energy	**1st**	**2nd**	**3rd**	**4th**
2013	(millions, except per share amounts)			
Operating revenue	$ 542.2	$ 600.3	$ 765.0	$ 538.8
Operating income	86.1	143.6	271.7	67.8
Net income	26.0	63.6	143.1	17.5
Basic and diluted earnings per common share	0.17	0.41	0.93	0.11
2012				
Operating revenue	$ 479.7	$ 603.6	$ 746.2	$ 480.4
Operating income	49.0	150.0	277.0	62.9
Net income (loss)	(9.3)	58.1	146.4	4.7
Net income (loss) attributable to Great Plains Energy	(9.1)	58.1	146.2	4.7
Basic and diluted earnings (loss) per common share	(0.07)	0.41	0.95	0.03

	Quarter			
KCP&L	**1st**	**2nd**	**3rd**	**4th**
2013	(millions)			
Operating revenue	$ 366.7	$ 410.8	$ 522.0	$ 371.9
Operating income	52.3	93.4	176.8	40.0
Net income	16.2	44.2	96.4	12.2
2012				
Operating revenue	$ 327.0	$ 409.1	$ 508.0	$ 335.8
Operating income	31.6	99.9	177.8	39.4
Net income	2.3	43.7	90.2	5.4

Quarterly data is subject to seasonal fluctuations with peak periods occurring in the summer months.

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, 2013 and 2012, and the related consolidated statements of comprehensive income, common shareholders' equity and noncontrolling interest, and cash flows for each of the three years in the period ended December 31, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on the criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2014, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 26, 2014

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, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on the criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2014, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 26, 2014

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, 2013, 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, 2013. Management used for this evaluation the framework in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission.

Management has concluded that, as of December 31, 2013, 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, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* 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, 2013, based on the criteria established in *Internal Control - Integrated Framework (1992)* 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, 2013, of the Company and our report dated February 26, 2014, expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 26, 2014

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, 2013, 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, 2013. Management used for this evaluation the framework in *Internal Control - Integrated Framework (1992)* issued by the COSO of the Treadway Commission.

Management has concluded that, as of December 31, 2013, 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, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* 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, 2013, based on the criteria established in *Internal Control - Integrated Framework (1992)* 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, 2013, of the Company and our report dated February 26, 2014, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 26, 2014

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 2014 Proxy Statement (Proxy Statement), which will be filed with the SEC no later than March 28, 2014:

- 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 Company has 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, 2013, 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	520,129 [1]	$ — [2]	5,213,231
Equity compensation plans not approved by security holders	—	—	—
Total	520,129 [1]	$ — [2]	5,213,231

[1] Includes 430,009 performance shares at target performance levels and director deferred share units for 90,120 shares of Great Plains Energy common stock outstanding at December 31, 2013.

[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 section 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 2013 and 2012 and for other services rendered during 2013 and 2012 on behalf of KCP&L, as well as all out-of-pocket costs incurred in connection with these services:

Fee Category	2013	2012
Audit Fees	$ 1,316,164	$ 1,145,140
Audit-Related Fees	79,465	76,740
Tax Fees	41,340	106,222
All Other Fees	—	—
Total Fees	$ 1,436,969	$ 1,328,102

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 7, 2009 (Exhibit 3.1.1 to Form 10-Q for the quarter ended March 31, 2009).	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	*	Restated Articles of Consolidation of Kansas City Power & Light Company, restated as of October 26, 2010 (Exhibit 3.3 to Form 10-K for the year ended December 31, 2010).	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	*	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, 2010 (Exhibit 10.1.3 to Form 10-Q for the quarter ended March 31, 2010).	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, 2011 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2011).	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, 2012 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2012).	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, 2013 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.8	*+	Form of 2003 Nonqualified Stock Option Agreement (Exhibit 10.1.14 to Form 10-K for the year ended December 31, 2009).	Great Plains Energy KCP&L
10.9	*+	Form of Amendment to 2003 Stock Option Grants (Exhibit 10.1.9 to Form 10-Q for the quarter ended September 30, 2007).	Great Plains Energy KCP&L
10.10	*+	Form of 2010 three-year Performance Share Agreement (Exhibit 10.1.1 to Form 10-Q for the quarter ended March 31, 2010).	Great Plains Energy KCP&L
10.11	*+	Form of 2010 Restricted Stock Agreement (Exhibit 10.1.2 to Form 10-Q for the quarter ended March 31, 2010).	Great Plains Energy KCP&L
10.12	*+	Form of 2011 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2011).	Great Plains Energy KCP&L
10.13	*+	Form of 2011 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2011).	Great Plains Energy KCP&L
10.14	*+	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
10.15	*+	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
10.16	*+	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
10.17	*+	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
10.18	*+	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

10.19	*+	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, 2013 (Exhibit 10.4 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.20	*+	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
10.21	*+	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
10.22	*+	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
10.23	*+	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
10.24	*+	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
10.25	*+	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
10.26	*+	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
10.27	*+	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
10.28	*+	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
10.29	*+	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
10.30	*+	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
10.31	*+	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

10.32	*	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
10.33	*	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
10.34	*	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
10.35	*	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
10.36	*	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	*	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
10.40	*	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
10.41	*	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
10.42	*	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
10.43	*	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
10.44	*	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

10.45	*	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
10.46	*	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
10.47	*	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
10.48	*	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
10.49	*	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
10.50	*	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
10.51	*	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
10.52	*	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

10.53	*	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
10.54	*	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
10.55	*	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
10.56	*	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
10.57	*	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
10.58	*	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
10.59	*	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
10.60	*	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
10.61	*	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

10.62	*	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 James C. Shay.	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 James C. Shay.	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	2013	2012	2011
Operating Expenses	(millions, except per share amounts)		
General and administrative	$ 1.0	$ 3.3	$ 0.8
General taxes	0.6	0.7	0.9
Total	1.6	4.0	1.7
Operating loss	(1.6)	(4.0)	(1.7)
Equity in earnings from subsidiaries	256.5	219.2	200.8
Non-operating income	45.8	42.7	24.7
Interest charges	(54.7)	(69.6)	(66.5)
Income before income taxes	246.0	188.3	157.3
Income tax benefit	4.2	11.6	17.1
Net income	250.2	199.9	174.4
Preferred stock dividend requirements	1.6	1.6	1.6
Earnings available for common shareholders	$ 248.6	$ 198.3	$ 172.8
Average number of basic common shares outstanding	153.5	145.5	135.6
Average number of diluted common shares outstanding	153.7	147.2	138.7
Basic earnings per common share	$ 1.62	$ 1.36	$ 1.27
Diluted earnings per common share	$ 1.62	$ 1.35	$ 1.25
Cash dividends per common share	$ 0.8825	$ 0.855	$ 0.835
Comprehensive Income			
Net income	$ 250.2	$ 199.9	$ 174.4
Other comprehensive income			
Derivative hedging activity			
Loss on derivative hedging instruments	—	—	(5.3)
Income tax benefit	—	—	2.1
Net loss on derivative hedging instruments	—	—	(3.2)
Reclassification to expenses	9.9	11.5	8.2
Income tax expense	(3.9)	(4.6)	(3.2)
Net reclassification to expenses	6.0	6.9	5.0
Derivative hedging activity, net of tax	6.0	6.9	1.8
Other comprehensive income from subsidiaries, net of tax	7.1	4.5	4.5
Total other comprehensive income	13.1	11.4	6.3
Comprehensive income	$ 263.3	$ 211.3	$ 180.7

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	
	2013	2012
ASSETS	(millions, except share amounts)	
Current Assets		
Accounts receivable from subsidiaries	**$ 0.2**	$ 0.1
Notes receivable from subsidiaries	**0.6**	0.6
Money pool receivable	**9.4**	4.0
Taxes receivable	**0.2**	—
Other	**1.2**	2.4
Total	**11.6**	7.1
Investments and Other Assets		
Investment in KCP&L	**2,179.3**	2,096.7
Investment in other subsidiaries	**1,447.0**	1,405.4
Note receivable from subsidiaries	**634.9**	883.6
Deferred income taxes	**31.4**	32.3
Other	**6.7**	7.6
Total	**4,299.3**	4,425.6
Total	**$ 4,310.9**	$ 4,432.7
LIABILITIES AND CAPITALIZATION		
Current Liabilities		
Notes payable	**$ 9.0**	$ 12.0
Current maturities of long-term debt	**—**	250.0
Accounts payable to subsidiaries	**33.6**	34.1
Accrued taxes	**0.2**	0.5
Accrued interest	**4.2**	6.8
Other	**1.5**	2.1
Total	**48.5**	305.5
Deferred Credits and Other Liabilities	**6.6**	5.2
Capitalization		
Great Plains Energy common shareholders' equity		
Common stock - 250,000,000 shares authorized without par value		
153,995,621 and 153,779,806 shares issued, stated value	**2,631.1**	2,624.7
Retained earnings	**871.4**	758.8
Treasury stock - 129,290 and 250,236 shares, at cost	**(2.8)**	(5.1)
Accumulated other comprehensive loss	**(25.3)**	(38.4)
Total	**3,474.4**	3,340.0
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	**10.0**	10.0
4.50% - 100,000 shares issued	**10.0**	10.0
4.20% - 70,000 shares issued	**7.0**	7.0
4.35% - 120,000 shares issued	**12.0**	12.0
Total	**39.0**	39.0
Long-term debt	**742.4**	743.0
Total	**4,255.8**	4,122.0
Commitments and Contingencies		
Total	**$ 4,310.9**	$ 4,432.7

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	2013	2012	2011
Cash Flows from Operating Activities		(millions)	
Net income	**$ 250.2**	$ 199.9	$ 174.4
Adjustments to reconcile income to net cash from operating activities:			
Amortization	**10.6**	12.6	11.2
Deferred income taxes, net	**(10.5)**	(4.8)	(18.6)
Equity in earnings from subsidiaries	**(256.5)**	(219.2)	(200.8)
Cash flows affected by changes in:			
Accounts receivable from subsidiaries	**(0.1)**	(0.1)	—
Taxes receivable	**(0.2)**	0.9	6.3
Accounts payable to subsidiaries	**(0.5)**	2.3	(0.3)
Other accounts payable	**0.1**	—	—
Accrued taxes	**(0.1)**	(4.4)	5.2
Accrued interest	**(2.6)**	6.1	1.2
Cash dividends from subsidiaries	**140.0**	144.0	148.0
Interest rate hedge settlement	—	—	(26.1)
Uncertain tax positions	**7.3**	1.0	(3.3)
Other	**6.8**	1.7	5.4
Net cash from operating activities	**144.5**	140.0	102.6
Cash Flows from Investing Activities			
Intercompany lending	**248.7**	(287.4)	(347.4)
Net money pool lending	**(5.4)**	(3.1)	1.1
Other	**(0.5)**	—	—
Net cash from investing activities	**242.8**	(290.5)	(346.3)
Cash Flows from Financing Activities			
Issuance of common stock	**4.9**	293.0	5.9
Issuance of long-term debt	—	—	349.7
Issuance fees	**(0.4)**	(2.7)	(3.2)
Repayment of long-term debt	**(250.0)**	—	—
Net change in short-term borrowings	**(3.0)**	(10.0)	12.5
Dividends paid	**(137.3)**	(125.5)	(115.1)
Other financing activities	**(1.5)**	(4.3)	(6.4)
Net cash from financing activities	**(387.3)**	150.5	243.4
Net Change in Cash and Cash Equivalents	—	—	(0.3)
Cash and Cash Equivalents at Beginning of Year	—	—	0.3
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, 2013, 2012 and 2011

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, 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
Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 6.8	$ 12.0	$ 7.8 [a]	$ 19.7 [b]	$ 6.9
Legal reserves	6.7	(0.2)	—	1.9 [c]	4.6
Environmental reserves	2.5	—	—	0.2	2.3
Tax valuation allowance	23.9	0.3	—	0.4 [d]	23.8
Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 7.0	$ 13.7	$ 6.9 [a]	$ 20.8 [b]	$ 6.8
Legal reserves	10.2	(0.1)	—	3.4 [c]	6.7
Environmental reserves	2.5	—	—	—	2.5
Tax valuation allowance	26.6	0.1	—	2.8 [d]	23.9

(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, 2013, 2012 and 2011

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, 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
Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 1.4	$ 7.9	$ 5.2 [a]	$ 13.0 [b]	$ 1.5
Legal reserves	3.9	0.5	—	1.5 [c]	2.9
Environmental reserves	0.3	—	—	—	0.3
Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 1.5	$ 8.8	$ 4.5 [a]	$ 13.4 [b]	$ 1.4
Legal reserves	3.0	1.3	—	0.4 [c]	3.9
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 26, 2014

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)	February 26, 2014
/s/ James C. Shay James C. Shay	Senior Vice President - Finance and Strategic Development and Chief Financial Officer (Principal Financial Officer)	
/s/ Lori A. Wright Lori A. Wright	Vice President - Business Planning and Controller (Principal Accounting Officer)	
David L. Bodde*	Director	
Randall C. Ferguson, Jr.*	Director	
Gary D. Forsee*	Director	
Thomas D. Hyde*	Director	
James A. Mitchell*	Director	
Ann D. Murtlow*	Director	
John J. Sherman*	Director	
Linda H. Talbott*	Director	
Robert H. West*	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 26, 2014

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)	February 26, 2014
/s/ James C. Shay James C. Shay	Senior Vice President - Finance and Strategic Development and Chief Financial Officer (Principal Financial Officer)	
/s/ Lori A. Wright Lori A. Wright	Vice President - Business Planning and Controller (Principal Accounting Officer)	
David L. Bodde*	Director	
Randall C. Ferguson, Jr.*	Director	
Gary D. Forsee*	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
Senior Fellow and 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, the state's premier public institution of higher learning

THOMAS D. HYDE
Retired Executive Vice President, Legal Compliance, Ethics and Corporate Secretary of 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 Crestwood Midstream GP LLC and former Chief Executive Officer and President, NRGM GP, LLC

DR. LINDA H. TALBOTT
President and Chief Executive Officer, Talbott & Associates, consultants in strategic planning, philanthropic management and development

ROBERT H. WEST
Retired Chairman of the Board, Butler Manufacturing Company, a supplier of non-residential building systems, specialty components and construction services

OFFICERS
Great Plains Energy

TERRY BASSHAM
Chairman of the Board, President and Chief Executive Officer

JAMES C. SHAY
Senior Vice President - Finance and Strategic Development and Chief Financial Officer

HEATHER A. HUMPHREY
Senior Vice President - Human Resources and General Counsel

KEVIN E. BRYANT
Vice President - Investor Relations and Strategic Planning and Treasurer

CHARLES A. CAISLEY
Vice President - Marketing and Public Affairs

ELLEN E. FAIRCHILD
Vice President, Corporate Secretary and Chief Compliance Officer

LORI A. WRIGHT
Vice President - Business Planning and Controller

OFFICERS
KCP&L

TERRY BASSHAM
Chairman of the Board, President and Chief Executive Officer

SCOTT H. HEIDTBRINK
Executive Vice President and Chief Operating Officer

JAMES C. SHAY
Senior Vice President - Finance and Strategic Development and Chief Financial Officer

HEATHER A. HUMPHREY
Senior Vice President - Human Resources and General Counsel

MICHAEL L. DEGGENDORF
Senior Vice President - Corporate Services

DUANE D. ANSTAETT
Vice President - Delivery

KEVIN E. BRYANT
Vice President - Investor Relations and Strategic Planning and Treasurer

CHARLES A. CAISLEY
Vice President - Marketing and Public Affairs

ELLEN E. FAIRCHILD
Vice President, Corporate Secretary and Chief Compliance Officer

DARRIN R. IVES
Vice President - Regulatory Affairs

MARIA R. JENKS
Vice President - Supply Chain

CHARLES L. KING
Vice President - Information Technology

KEVIN T. NOBLET
Vice President - Generation

MARVIN L. ROLLISON
Vice President - Safety and Corporate Services

LORI A. WRIGHT
Vice President - Business Planning and Controller

Shareholder Information

GREAT PLAINS ENERGY FORM 10-K
Great Plains Energy's 2013 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 18,170 shareholders of record as of February 25, 2014.

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	2013	2012
First	$0.2175	$0.2125
Second	0.2175	0.2125
Third	0.2175	0.2125
Fourth	0.23	0.2175

CUMULATIVE PREFERRED STOCK DIVIDENDS
Quarterly dividends on preferred stock were declared in each quarter of 2013 and 2012 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

	2013		2012	
QUARTER	HIGH	LOW	HIGH	LOW
First	$23.19	$20.41	$21.60	$19.60
Second	24.41	21.94	21.41	19.54
Third	24.60	21.49	22.48	21.26
Fourth	24.76	21.86	22.81	19.80

ANNUAL MEETING OF SHAREHOLDERS
Great Plains Energy's annual meeting of shareholders will be held at 10:00 a.m., May 6, 2014, 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: 800-884-4225

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

2013

Annual Report

Dedicated to serving rural Kansas

Kansas Electric

Power Cooperative, Inc.

Contents

KEPCo Staff

Charles Terrill.....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

Mark Barbee.....Vice President of Engineering, KSI Vice President of Engineering

Chris Davidson.....Engineer 2

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

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

Stephanie Worthington..... Finance & Benefits Analyst

Organization & 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 14 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 700 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."

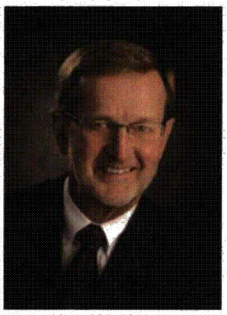
Kansas Electric
Power Cooperative, Inc.
P.O. Box 4877 Topeka, KS 66604
600 SW Corporate View Topeka, KS 66615
(785) 273-7010

A Touchstone Energy® Cooperative

2013 Message

from

Scott Whittington
KEPCo President



Charles Terrill
Executive Vice President
& Chief Executive Officer

In March, Mr. Charles "Chuck" Terrill was announced as KEPCo's fourth Executive Vice President & Chief Executive Officer (EVP & CEO). Mr. Terrill is not new to KEPCo. Prior to serving as the EVP & CEO of the North Carolina Association of Electric Cooperatives and the North Carolina Electric Membership Corporation from 1995 to 2007, Mr. Terrill served eight years as KEPCo's second EVP & CEO. Mr. Terrill has over thirty-five years of experience in the electric utility industry, primarily with electric cooperatives.

2013 was not only bookended by changes in leadership, both within KEPCo and with the KEPCo Board of Trustees, but change is occurring in the utility industry as well. Early in 2014, electric utilities that are members of the Southwest Power Pool (SPP), of which KEPCo is a member, will undergo a fundamental change in how electricity is dispatched. The SPP Integrated Marketplace will be implemented as the latest incremental step in SPP's evolutionary approach to improving service to SPP members and the region. The Integrated Marketplace will determine which generating units should run the next day for maximum cost effectiveness, provide participants with greater access to reserve electricity, improve regional balancing of supply and demand, and facilitate the integration of renewable resources. By working closely with SPP members, market participants, vendors, and customers, the SPP can focus collective energies on improving grid reliability and greater cost savings and efficiencies.

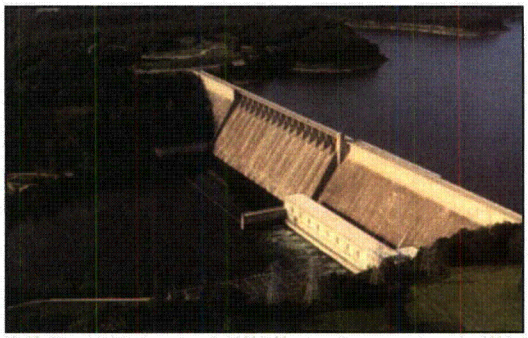
In order to accommodate the SPP Integrated Marketplace, KEPCo successfully completed negotiations with Westar Energy to formalize modifications to the existing Westar Generation Formula Rate Agreement. The modifications were necessary to adjust the methodology for billing KEPCo's usage and the crediting of KEPCo's generation resources. In addition, KEPCo negotiated agreeable terms with Westar Energy for an Energy Management Agreement (EMA). The EMA is a service agreement which allows

Westar, as the SPP Market Participant, to act as KEPCo's agent for the purposes of bidding, scheduling and settling KEPCo's generation resources in the SPP Integrated Marketplace.

The cost of electricity and regulatory uncertainty continue to be concerns. Over the past few years, electric utilities, particularly in the Midwest, have seen measurable increases in costs, driven substantially by the cost of environmental regulatory compliance. Controlling costs to keep wholesale rates as economic as possible is a principle responsibility and objective of KEPCo. In an effort to slow this upward cost trend, the KEPCo Board of Trustees approved the restructuring and refinancing of the original debt associated with the Wolf Creek Nuclear Generating Station (Wolf Creek). The debt has been extended to more closely match the useful life of the plant, which was granted an operating license extension to 2045. In December, as an immediate result of the restructuring, KEPCo, through its Margin Stabilization Adjustment, was able to apply a credit to the Member's December energy bill that reduced the average Member rate by four mills for the year. Over the life of the restructuring, KEPCo will be able to lower the principal payments on Wolf Creek, thus stabilizing, or potentially reducing, Wolf Creek's impact on wholesale rates.

In November, at KEPCo's Annual Meeting, Mr. Scott Whittington, manager of Lyon-Coffey Electric Cooperative, Inc., was unanimously elected as President of KEPCo, succeeding Mr. Kirk Thompson, manager of CMS Electric Cooperative, Inc. Mr. Thompson elected not to seek a fifth term. In addition to having over 15 years of electric cooperative experience, Mr. Whittington also serves on the CoBank Board and is a member of the CoBank Governance Committee, is a trustee for KEPCo, is an alternate trustee for Kansas Electric Cooperatives, and is an executive council member for Kansas Touchstone Energy Cooperatives.

At a time when the utility industry could use some certainty regarding the future of fossil fuel generation, particularly coal, the current administration seems to be moving in the opposite direction. Regulatory uncertainty hampers investment in generation resources, not only with new plants, but existing plants as well. Utilities across the nation are being forced to decide whether to invest millions of dollars in equipment to retrofit existing plants to comply with new, more stringent EPA regulations or to close plants and invest in other generation resources, which may also face new regulations in the future. Utilities cannot develop long-term generation resource plans when the regulations governing generation resources are constantly in flux.


Bull Shoals Dam

KEPCo is not immune to EPA regulations and associated costs. KEPCo's wholesale rate is impacted by EPA compliance expenditures by utilities from which KEPCo purchases energy. Even though KEPCo has exposure to these expenditures, KEPCo

has been able to shield its Members from substantial regulatory compliance costs through its partial ownership in Iatan 2, an 850 megawatt super-critical coal-fired plant, its six percent ownership of Wolf Creek, and its federal hydropower allocations. These three resources account for nearly 44 percent of KEPCo's energy supply.


Iatan 2

This year, the Iatan Generating Station was awarded the prestigious 2012 Power Plant Operational Excellence & Stewardship Award from GP Strategies. Iatan 2 achieved the best heat rate for a coal plant in the U.S. in 2012, and the entire Iatan Generating Station was the most efficient Powder River Basin coal-fired plant in the nation. The award recognizes efficiency and environmental stewardship, in addition to recognizing the efforts to restore 106 acres of Missouri River wetlands, which house rare wildlife, like peregrine falcons and bald eagles. As of December 31, Iatan 2 had run continuously for 289 days, and since commencing commercial operation in late 2010, Iatan 2 has met all EPA regulations without additional environmental controls.

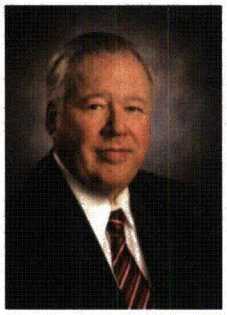
Re-fuel 19 was completed at Wolf Creek this year, which will provide the unit with enough fuel until the spring of 2015. During the outage, several upgrades and modifications were completed, which will improve the overall operation of the plant. Wolf Creek does not emit any flue gas or greenhouse gas, thus shielding KEPCo Members from the costs associated with EPA air emission regulations.


Wolf Creek Nuclear Generating Station

Looking ahead, strategic analysis has shown where KEPCo can further improve its power supply program and processes. In 2014, KEPCo will focus upon the implementation and operation of the SPP Integrated Marketplace, study demand-side management opportunities, study the options for the availability for future financing, simplify KEPCo's cost adjustment factors in the Member tariff, and develop additional financial and rate forecasting tools. By focusing on these areas, KEPCo will be able to further enhance its operations and continue to provide an economic and reliable power supply, as it has for nearly four decades.

In closing, the electric utility industry today is far different than that of just ten years ago. To say these are challenging times is an understatement. The ability to act and react in an ever-changing industry is critical for continued viability. KEPCo is fortunate to have a Board of Trustees and staff that have the vision and experience to perform and excel in such an environment. Through their combined leadership, KEPCo will continue to provide rural Kansas with a resource necessary for a quality way of life and economic vitality.

2013 KEPCo Highlights


Charles "Chuck" Terrill

Chuck Terrill was named Executive Vice President and Chief Executive Officer of KEPCo. Chuck returned to KEPCo, where he was previously the EVP & CEO from 1988 to 1995, after retiring as EVP & CEO of North Carolina Association of Electric Cooperatives and the North Carolina Electric Membership Corporation.

Iatan was recognized as the nation's most efficient coal-fired plant, as it was presented the 2012 Power Plant Operational Excellence & Stewardship Award by GP Strategies Corporation. The award is in recognition of the overall commitment to plant thermal efficiency and environmental stewardship.


Les Evans accepting Iatan award


Wolf Creek Nuclear Generating Station

KEPCo refinanced and restructured the debt associated with Wolf Creek. As such, KEPCo was able to lower the debt service on Wolf Creek, thus reducing the wholesale rate to Member Cooperatives in 2013 by four mills.

Re-fuel 19 was completed at Wolf Creek, which will provide the unit with enough fuel until the spring of 2015. Several upgrades and modifications were completed during the outage which will improve the overall operation of the plant.

In May, KEPCo successfully appealed the Department of Revenue's notice of property valuation. In June, KEPCo worked with KEC to further appeal the appraisal before the Court of Tax Appeals (COTA). In September, COTA issued an order, resulting in additional tax savings for KEPCo.

KEPCo provided technical consultation to Members on energy issues in areas such as generator interconnections, purchase power agreements, metering, regulatory and policy matters.


Member-owned wind generation

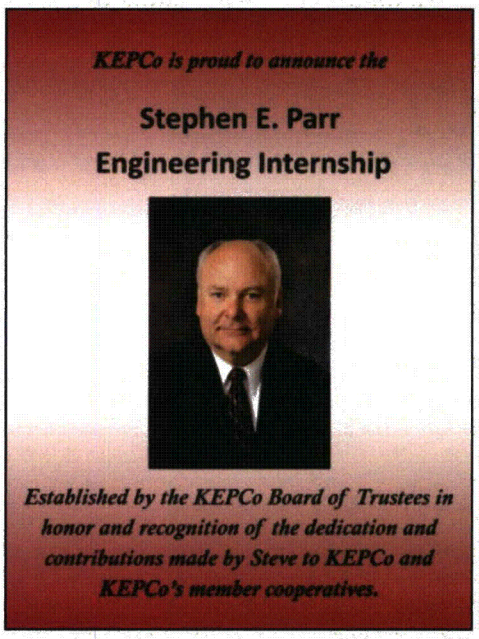
For 16 years, KSI has provided valuable engineering services for KEPCo Members, while covering its expenses and contributing to KEPCo overheads. Over the past year, KSI has been involved in over 60 projects for 12 KEPCo Members and two non-members.

KSI Engineering


U.S. Capitol, Washington, D.C.

KEPCo Staff continues to work diligently with KEC and Sunflower on legislative issues in Kansas and Washington, D.C. Staff testified on several bills in 2013 and tracked numerous pieces of legislation. In Washington, D.C., Staff participated in the NRECA Legislative Conference.

In memory and honor of Mr. Stephen Parr, KEPCo's EVP & CEO from 1996 to 2013, the KEPCo Board of Trustees unanimously approved the establishment of the Stephen E. Parr Engineering Internship, an electric engineering summer internship for students attending Kansas universities.



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 settled a long-standing issue with Sunflower, MKEC, Victory and Prairie Land regarding power supply to areas previously served by Aquila.

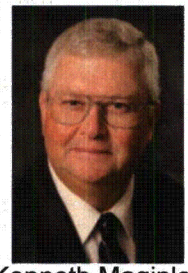
Safety of our employees is essential to the continued operational success of KEPCo. Several safety meetings are conducted throughout the year for KEPCo's SCADA Technicians and administrative personnel. KEPCo is proud to report there were no lost time accidents recorded in 2013.

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 -- Bob Hall
Manager -- Bob Hall


Bob Hall

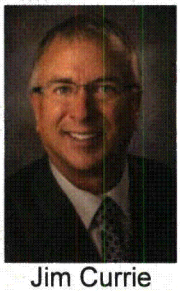

Kenneth Maginley

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

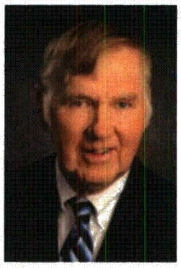

Kevin Compton

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

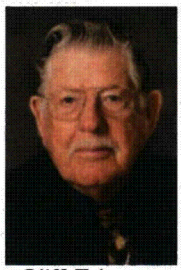

Dwane Kessinger

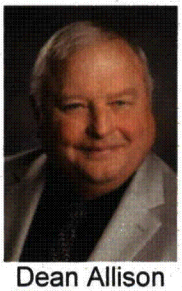
Caney Valley Electric Cooperative Assn., Inc.
PO Box 308, Cedar Vale, KS 67204 620-758-2262
Trustee Rep. -- Dwane Kessinger
Alternate Trustee -- Allen A. Zadorozny
Manager -- Allen A. Zadorozny


Allen Zadorozny

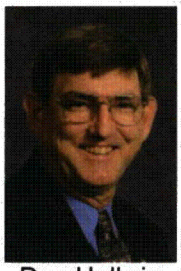

Kirk Thompson

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

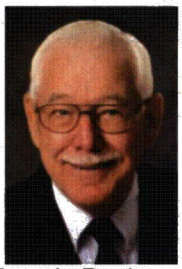
DS&O Electric Cooperative, Inc.
PO Box 286, Solomon, KS 67480 785-655-2011
Trustee Rep. -- Dean Allison
Alternate Trustee -- Donald Hellwig
Manager -- Donald Hellwig


Don Hellwig


Bob Reece

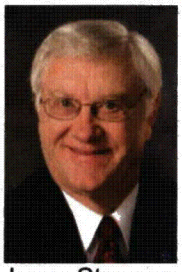
Flint Hills Electric Cooperative Assn., Inc.
PO Box B, Council Grove, KS 66846 620-767-5144
Trustee Rep. -- Robert E. Reece
Alternate Trustee -- William Hein
Manager -- Robert E. Reece


William Hein


Dennis Peckman

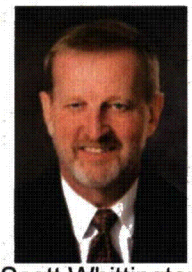
Heartland Rural Electric Cooperative, Inc.
PO Box 40, Girard, KS 66743 620-724-8251
Trustee Rep. -- Dennis Peckman
Alternate Trustee -- Dale Coomes
Manager -- Dale Coomes


Dale Coomes

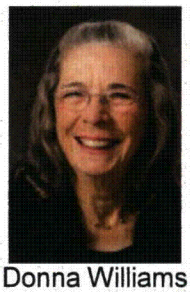

Larry Stevens

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

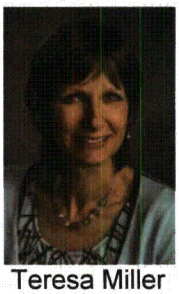
Lyon-Coffey Electric Cooperative, Inc.
PO Box 229, Burlington, KS 66839 620-364-2116
Trustee Rep. -- Scott Whittington
Alternate Trustee -- Donna Williams
Manager -- Scott Whittington

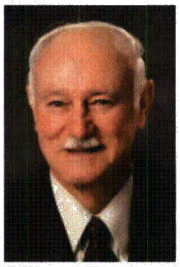

Donna Williams

KEPCo Member Cooperatives
Trustees, Alternates and Managers

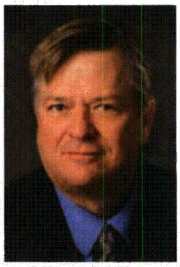

Curtis Durall

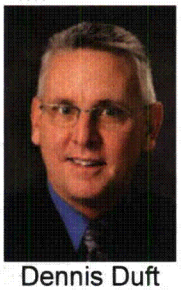
Ninnescah Electric Cooperative Assn., Inc.
PO Box 967, Pratt, KS 67124 620-672-5538
Trustee Rep. -- Curtis Durall
Alternate Trustee -- Teresa Miller
Manager -- Teresa Miller


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

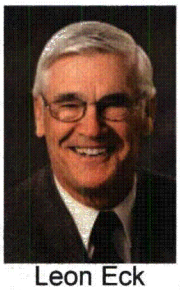

Allan Miller


Dennis Duft

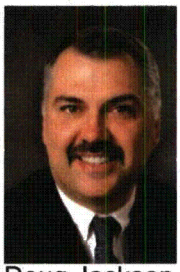
Radiant Electric Cooperative, Inc.
PO Box 390, Fredonia, KS 66736 620-378-2161
Trustee Rep. -- Dennis Duft
Alternate Trustee -- Donald Songer
Administrative Manager -- Leah Tindle
Operations Manager -- Dennis Duft


Don Songer


Leah Tindle

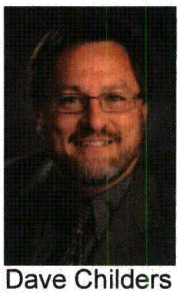

Leon Eck

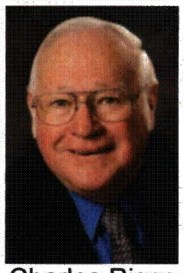
Rolling Hills Electric Cooperative, Inc.
PO Box 307, Mankato, KS 66956 785-378-3151
District Offices, Belleville 785-527-2251
Ellsworth 785-472-4021
Trustee Rep. -- Leon Eck
Alternate Trustee -- Douglas J. Jackson
Manager -- Douglas J. Jackson


Doug Jackson


Donald Metzen

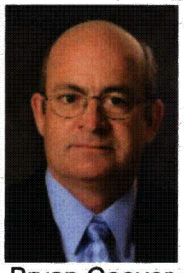
Sedgwick County Electric Cooperative Assn., Inc.
PO Box 220, Cheney, Ks 67025 316-542-3131
Trustee Rep. -- Donald Metzen
Alternate Trustee -- David Childers
Manager -- David Childers


Dave Childers

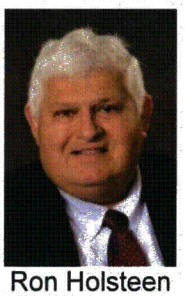

Charles Riggs

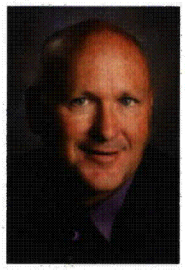
Sumner-Cowley Electric Cooperative, Inc.
PO Box 220, Wellington, KS 67152 620-326-3356
Trustee Rep. -- Charles Riggs
Alternate Trustee -- Cletas Rains
Manager -- Cletas Rains


Cletas Rains

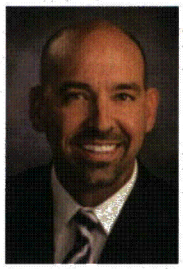

Bryan Coover

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


Daryl Tieben

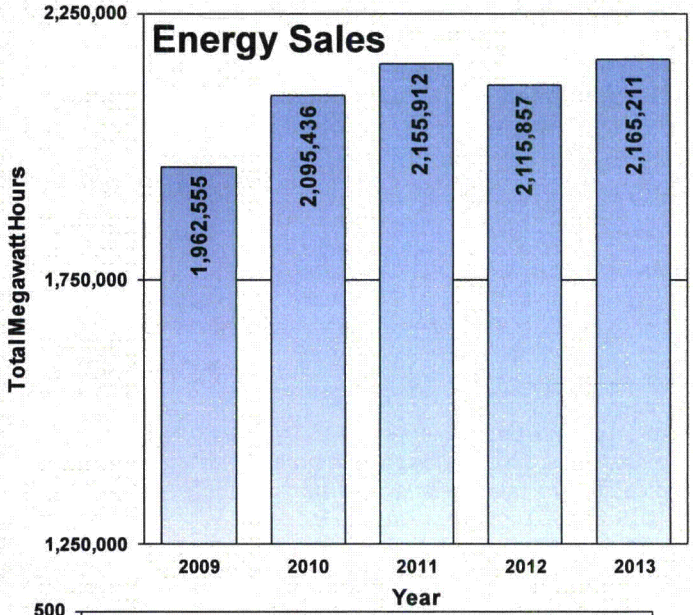
Victory Electric Cooperative Assn., Inc.
PO Box 1335, Dodge City, KS 67801 620-227-2139
Trustee Rep. -- Daryl Tieben
Alternate Trustee -- Shane Laws
Manager -- Shane Laws

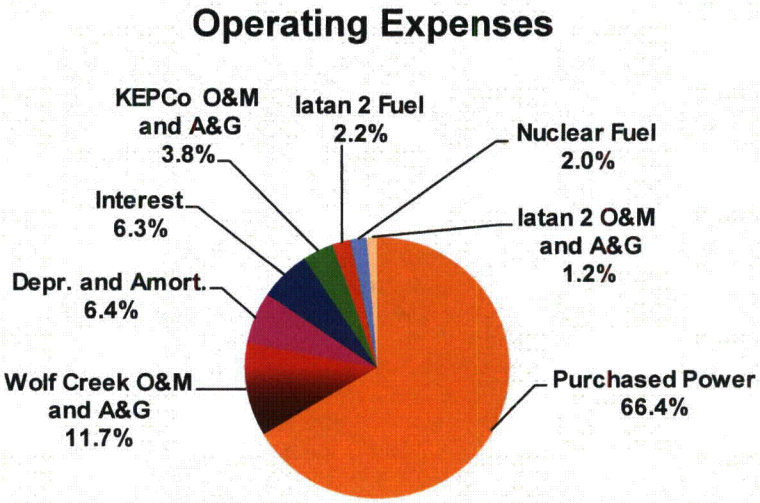

Shane Laws

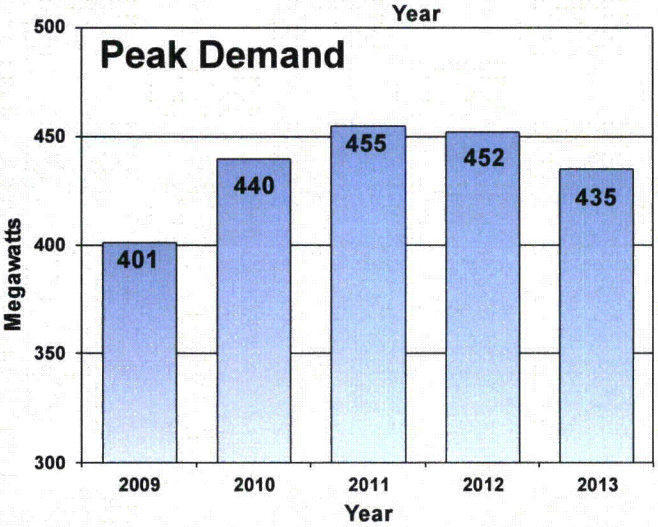
2013 - 2014 KEPCo Executive Committee

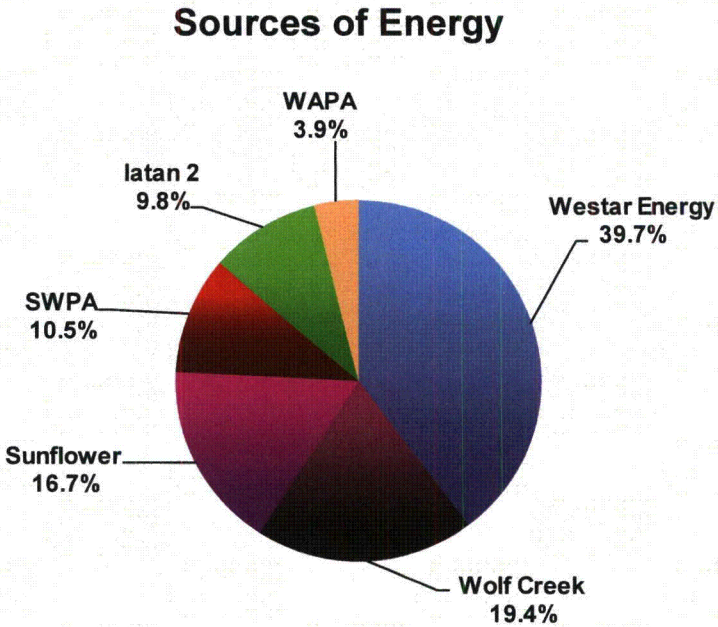
Scott Whittington - President
Kevin Compton - Vice President
Dale Short - Treasurer
Dean Allison - Secretary
Kenneth Maginley - Committee Member
Larry Stevens - Committee Member
Kirk Thompson - Committee Member

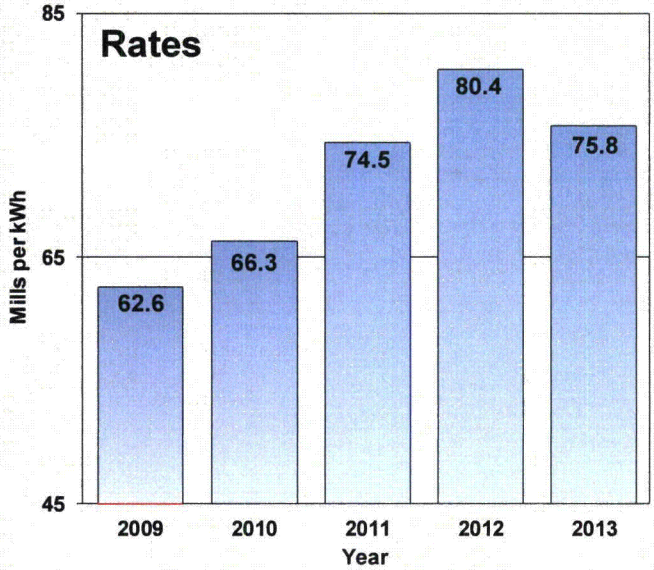
Operating Statistics











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, 2013 and 2012, 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.

Auditor's 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 2013 and 2012 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, 2013 and 2012, 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 3, 2014, 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 3, 2014

Consolidated Balance Sheets

Assets	December 31, 2013	December 31, 2012
Utility Plant		
In-service	$ 318,326,772	$ 307,831,825
Less allowances for depreciation	(143,755,156)	(137,817,916)
Net in-service	174,571,616	170,013,909
Construction work in progress	18,837,972	12,700,102
Nuclear fuel (less accumulated amortization of $19,911,283 and $19,473,196 for 2013 and 2012, respectively)	7,806,307	10,122,622
Total utility plant	201,215,895	192,836,633
Restricted Assets		
Investments in the National Utilities Cooperative Finance Corporation	12,094,536	12,130,495
Bond fund reserve	4,465,868	4,439,704
Decommissioning fund	17,844,344	14,902,017
Investments in other associated organizations	252,077	233,560
Total restricted assets	34,656,825	31,705,776
Current Assets		
Cash and cash equivalents	5,181,544	2,824,134
Member account receivables	5,664,940	13,274,272
Materials and supplies inventory	5,756,835	5,270,885
Other assets and prepaid expenses	734,937	841,441
Total current assets	17,338,256	22,210,732
Other Long-term Assets		
Deferred charges		
Wolf Creek disallowed costs (less accumulated amortization of $16,420,880 and $15,663,720 for 2013 and 2012, respectively)	9,562,041	10,319,201
Wolf Creek deferred plants costs (less accumulated amortization of $37,559,034 and $34,429,111 for 2013 and 2012, respectively)	9,389,759	12,519,682
Wolf Creek decommissioning regulatory asset	(6,499,881)	(4,328,140)
Deferred incremental outage costs	6,259,359	1,286,856
Other deferred charges (less accumulated amortization of $9,279,497 and $8,991,323 for 2013 and 2012, respectively)	801,338	1,184,847
Unamortized debt issuance costs	147,664	225,477
Other	235,182	676,008
Prepaid pension cost	1,545,694	-
Total long-term assets	21,441,156	21,883,931
Total assets	$ 274,652,132	$ 268,637,072

Consolidated Balance Sheets

Liabilities and Patronage Capital	December 31, 2013	December 31, 2012
Patronage Capital		
Memberships	$ 3,200	$ 3,200
Patronage Capital	70,025,317	67,431,537
Accumulated other comprehensive loss	(4,071,781)	(8,789,873)
Total patronage capital	65,956,736	58,644,864
Long-term Debt	140,460,064	149,068,800
Other Long-term Liabilities		
Wolf Creek decommissioning liability	12,542,673	11,810,322
Wolf Creek pension and postretirement benefit plans	7,432,482	11,487,819
Wolf Creek deferred compensation	1,120,601	1,035,171
Other deferred credits	-	41,432
Total other long-term liabilities	21,095,756	24,374,744
Current Liabilities		
Current maturities of long-term debt	22,493,911	20,070,937
Accounts payable	14,523,217	13,923,363
Payroll and payroll-related liabilities	243,044	345,883
Short term note payable	6,500,000	-
Deferred revenue	1,224,424	-
Accrued property taxes	1,519,915	1,587,064
Accrued income taxes	-	(1,092)
Accrued interest payable	635,065	622,509
Total current liabilities	47,139,576	36,548,664
Total patronage capital and liabilities	$ 274,652,132	$ 268,637,072

Consolidated Statements of Margin

	For the years ending December 31, 2013	2012
Operating Revenues		
Sale of electric energy	$ 164,048,145	$ 170,131,188
Operating Expenses		
Power purchased	107,958,510	104,171,556
Nuclear fuel	3,303,643	3,511,788
Plant operations	18,223,619	17,587,807
Plant maintenance	6,115,338	6,616,513
Administrative and general	6,105,859	6,021,574
Amortization of deferred charges	4,185,313	4,245,720
Depreciation and decommissioning	6,944,842	6,902,435
Total operating expenses	152,837,124	149,057,393
Net operating revenues	11,211,021	21,073,795
Interest and Other Deductions		
Interest on long-term debt	9,599,108	10,303,239
Amortization of debt issuance costs	77,813	86,954
Other deductions	190,317	79,752
Total interest and other deductions	9,867,238	10,469,945
Operating income	1,343,783	10,603,850
Other Income/(Expense)		
Interest income	859,711	974,021
Other income	390,286	338,700
Total other income	1,249,997	1,312,721
Net margin	$ 2,593,780	$ 11,916,571
Net Margin	$ 2,593,780	$ 11,916,571
Other comprehensive income		
Net earnings (loss) arising during year on pension obligation	3,984,833	(759,456)
Less amortization of prior year service costs included in net periodic pension costs	733,259	723,090
Comprehensive income	$ 7,311,872	$ 11,880,205

Consolidated Statements of Patronage Capital

	Memberships	Patronage Capital	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2011	$ 3,200	$ 55,514,966	$ (8,753,507)	$ 46,764,659
Net margin	-	11,916,571	-	11,916,571
Defined benefit pension plans:				
Net loss arising during year	-	-	(759,456)	(759,456)
Less amortization of prior year service costs included in net periodic pension costs	-	-	723,090	723,090
Balance at December 31, 2012	3,200	67,431,537	(8,789,873)	58,644,864
Net margin	-	2,593,780	-	2,593,780
Defined benefit pension plans:				
Net earnings arising during year	-	-	3,984,833	3,984,833
Less amortization of prior year service costs included in net periodic pension costs	-	-	733,259	733,259
Balance at December 31, 2013	$ 3,200	$ 70,025,317	$ (4,071,781)	$ 65,956,736

Consolidated Statements of Cash Flows

	For the years ending December 31, 2013	2012
Cash Flows From Operating Activities		
Net margin	$ 2,593,780	$ 11,916,571
Adjustments to reconcile net margin to net cash flows from operating activities		
Depreciation and amortization	6,540,599	6,417,670
Decommissioning	2,904,092	1,500,024
Amortization of nuclear fuel	2,819,442	3,004,990
Amortization of deferred charges	4,175,257	4,245,720
Amortization or deferred incremental outage costs	5,386,940	7,179,415
Amortization of debt issuance costs	77,813	86,953
Changes in		
Member accounts receivable	7,609,332	(5,624,402)
Materials and supplies	(485,950)	(899,836)
Other assets and prepaid expense	106,504	(305,776)
Accounts payable	599,854	2,607,180
Payroll and payroll-related liabilities	(102,839)	17,531
Accrued property tax	(67,149)	180,292
Accrued interest payable	12,556	(34,313)
Accrued income taxes	1,092	(847)
Other long-term liabilities	1,147,579	(106,340)
Prepaid pension cost	(1,545,694)	-
Deferred revenue	1,224,424	-
Net cash flows from operating activities	32,997,632	30,184,832
Cash Flows From Investing Activities		
Additions to electrical plant	(17,278,012)	(9,658,692)
Additions to nuclear fuel	(503,127)	(3,709,772)
(Reductions in)/additions to deferred charges	95,335	(280,455)
Additions to deferred incremental outage costs	(10,359,443)	(900,384)
Investments in decommissioning fund assets	(2,942,327)	(1,966,895)
Investments in associated organizations	17,442	304,392
Investments in bond reserve assets	(26,164)	(24,930)
Proceeds from the sale of property	41,837	7,958
Net cash flows from investing activities	(30,954,459)	(16,228,778)
Cash Flows From Financing Activities		
Principal payments on long-term debt	(20,168,539)	(18,781,860)
Proceeds from issuance of long-term debt	11,594,273	1,048,000
Short term notes payable	6,500,000	-
Payments unapplied	2,388,503	(2,388,504)
Net cash flows from financing activities	314,237	(20,122,364)
Net increase (decrease) in cash and cash equivalents	2,357,410	(6,166,310)
Cash and Cash Equivalents, Beginning of Year	2,824,134	8,990,444
Cash and Cash Equivalents, End of Year	$ 5,181,544	$ 2,824,134
Supplemental Disclosure of Cash Flow Information		
Interest paid	$ 9,776,900	$ 10,417,400

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), 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.

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 jointly owned 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.

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 2013 and 2012. 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, 2013 and 2012 are 3.77% and 3.63%, 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

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 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. The permanent disposal of spent fuel is the responsibility of the Department of Energy (DOE). KEPCo pays one dollar per net megawatt (MWh) of nuclear generation to the DOE for the future disposal service. These disposal costs are charged to nuclear fuel expense.

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 2011, 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 $37.8 million. This amount compares to the prior site study estimate of $35.6 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.

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 2013 and $0.5 million in 2012. KEPCo records its investment in the NDT fund at fair value, which approximated $17.8 million and $14.9 million as of December 31, 2013 and 2012, 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, 2013 and 2012 is as follows:

	2013	2012
Balance at January 1	$11,810,322	$16,298,000
Accretion	732,351	622,388
Decrease from 2011 study	-	(5,110,066)
Balance at December 31	$12,542,673	$11,810,322

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.

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.

	2013	2012
Cash surrender value of contracts	$ 6,814,094	$ 6,470,143
Borrowings against contracts	(6,578,912)	(6,246,370)
	$ 235,182	$ 223,773

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, 2013 and 2012.

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 2010.

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.

There has been no interest or penalties recognized neither in the statements of margin nor in the balance sheets related to uncertain tax positions. In addition, no tax positions exist for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease within the next twelve months. Tax years with open statutes of limitations are 2010 and forward.

(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.

(3) Departures From Generally Accepted Accounting Principles

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:

	2013	2012
Deferred charges	$ 10,690,902	$ 14,254,536
Patronage capital	$ 10,690,902	$ 14,254,536
Net margin	$ (3,563,634)	$ (3,563,634)

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 ($9.6 million net of accumulated amortization as of December 31, 2013). 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, 2013, and 2012.

Wolf Creek Deferred Plant Costs - 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, 2013 and 2012.

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.

(4) Investments in Associated Organizations

Investments in associated organizations are carried at cost. At December 31, 2013 and 2012, investments in associated organizations consisted of the following:

	2013	2012
Cooperative Financial Corporation		
Memberships	$ 1,000	$ 1,000
Capital term certificates	395,970	395,970
Patronage capital certificates	1,054,664	792,064
Equity term certificates	8,142,902	8,441,461
Member capital certificates	2,500,000	2,500,000
	12,094,536	12,130,495
Other	252,077	233,560
	$ 12,346,613	$ 12,364,055

(5) Bond Fund Reserve

KEPCo has entered into a bond covenant whereby KEPCo is required to maintain, with a trustee, a bond fund reserve of approximately $4.4 million. This stipulated amount is sufficient to satisfy certain future interest and principal obligations. The amount held in the bond fund reserve is invested by the trustee in tax-exempt municipal securities, pursuant to the restrictions of the indenture agreement, which are carried at amortized cost.

(6) 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 $10.4 million and $0.9 million in 2013 and 2012, respectively. The current year amortization of the deferred incremental outage costs was $5.4 million and $7.2 million in 2013 and 2012, 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.

(7) Line of Credit

As of December 31, 2013, 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, 2013. 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, 2013, and 2.90% at December 31, 2012. This line of credit expires in November 2016.

At December 31, 2013, 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, 2013. 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 2015.

(8) Short-Term Note Payable

As of December 31, 2013, KEPCo has a $5.0 million short-term note payable to the Cooperative Finance Corporation at an interest rate of 2.4% and a $1.5 million short-term note payable to the Cooperative Finance Corporation at an interest rate of 2.5%.

(9) 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:

	2013	2012
Mortgage notes payable to the FFB at fixed rates varying from .818% to 9.21%, payable in quarterly installments through 2043	$ 49,124,279	$ 53,630,090
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	18,440,000	23,240,000
Floating/fixed rate pollution control revenue bonds, City of Burlington, Kansas, Pooled Series 1985C, variable interest rate of .34%, payable annually through 2015	5,795,000	9,195,000
Note payable to CoBank at a rate of 3.03%, payable in quarterly installments through 2023	1,228,745	-
Mortgage notes payable, equity certificate loans and member capital security notes to the CFC at fixed rates of 2.45% to 7.70%, payable quarterly through 2045	88,365,951	83,074,647
	162,953,975	169,139,737
Less current maturities	(22,493,911)	(20,070,937)
	$ 140,460,064	$ 149,068,800

Aggregate maturities of long-term debt for the next five years and thereafter are as follows:

2014	$ 22,493,911
2015	21,778,575
2016	12,657,100
2017	11,169,716
2018	7,825,675
Thereafter	87,028,998
	$ 162,953,975

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, 2013 and 2012.

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, 2013.

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 the Cooperative 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, 2013, the termination obligation associated with the assigned swap agreement to early retire the mortgage notes payable is approximately $2.7 million.

This fair value estimate is based on information available at December 31, 2013, 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.

(10) 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.

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 RS Plan in 2013 and 2012 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, and $0.5 million, for the year ended December 31, 2013 and 2012, respectively. There have been no significant changes that affect the comparability of 2013 and 2012 contributions.

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 $90,000, and $100,000 to the plan for the years ended December 31, 2013 and 2012, respectively.

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.

	Pension Benefits		Postretirement Benefits	
	2013	2012	2013	2012
Change in benefit obligation:				
Benefit obligation beginning of year	$22,581,857	$20,603,780	$ 1,406,813	$ 1,293,078
Service cost	872,519	773,872	26,348	24,483
Interest cost	965,450	962,263	52,648	52,432
Plan participants' contributions	-	-	88,823	77,589
Benefits paid	(555,243)	(1,094,009)	(130,531)	(126,126)
Actuarial (gains) losses	(3,079,040)	1,252,917	(166,348)	85,357
Amendments	-	83,034	-	-
Benefit obligations, end of year	$20,785,543	$22,581,857	$ 1,277,753	$ 1,406,813

	Pension Benefits		Postretirement Benefits	
	2013	2012	2013	2012
Change in plan assets:				
Fair value of plan assets, beginning of year	$12,517,154	$ 10,305,630	$ 1,698	$ 487
Actual return on plan assets	1,680,711	1,501,730	-	-
Employer contributions	973,210	1,772,810	42,000	49,748
Plan participants' contributions	-	-	88,823	77,589
Benefits paid	(524,251)	(1,063,016)	(130,531)	(126,126)
Fair value of plan assets, end of year	14,646,824	12,517,154	1,990	1,698
Funded status, end of year	$ (6,138,719)	$(10,064,703)	$(1,275,763)	$(1,405,115)

Amounts recognized in the consolidated balance sheets:

	2013	2012
Other long-term liabilities		
Wolf Creek pension and postretirement benefit plans	$ 7,432,482	$ 11,487,819

Amounts recognized in accumulated other comprehensive income (loss) not yet recognized as components of net periodic benefit cost consist of:

	Pension Benefits		Postretirement Benefits	
	2013	2012	2013	2012
Net loss	$ (3,728,059)	$ (8,238,528)	$ (264,963)	$ (465,118)
Prior service cost	(78,759)	(86,195)	-	-
Transition obligation	-	-	-	(32)
Accumulated other comprehensive loss	$ (3,806,818)	$ (8,324,723)	$ (264,963)	$ (465,150)

Information for the pension plan with an accumulated benefit obligation in excess of plan assets:

	Pension Benefits		Postretirement Benefits	
	2013	2012	2013	2012
Projected benefit	$ 20,785,543	$ 22,581,857	$ 1,277,752	$ 1,406,813
Accumulated benefit obligation	17,547,994	18,092,202	-	-
Fair value of plan assets	$ 14,646,824	$ 12,517,154	$ 1,990	$ 1,698

Weighted average actuarial assumptions used to determine net periodic benefit obligation:

	Pension Benefits		Postretirement Benefits	
	2013	2012	2013	2012
Discount rate	4.16%	4.16%	4.70%	3.78%
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.

	Pension Benefits		Postretirement Benefits	
	2013	2012	2013	2012
Components of net periodic cost (benefit):				
Service cost	$ 872,519	$773,872	$26,348	$24,483
Interest cost	965,450	962,263	52,648	52,432
Expected return on plant assets	(941,266)	(839,619)	-	-
Amortization				
Transition obligation, net	-	-	32	7,350
Prior service cost	7,436	714	-	-
Actuarial loss, net	691,984	685,000	33,807	29,767
Net periodic cost	$1,596,123	$1,582,230	$112,835	$114,032

	Pension Benefits		Postretirement Benefits	
	2013	2012	2013	2012
Other changes in plan obligations recognized in other comprehensive income:				
Current year actuarial loss(gain)	$ (3,818,485)	$ 590,806	$ (166,348)	$ 85,357
Amortization of actuarial loss	(691,984)	(685,000)	(33,807)	(29,767)
Current year prior service cost	-	83,034		-
Amortization of prior service cost	(7,436)	(714)	-	-
Amortization of transition obligation	-	-	(32)	(7,350)
Total recognized in other comprehensive income	(4,517,905)	(11,874)	(200,187)	48,240
Total recognized in net periodic cost and other comprehensive income	$ (2,921,782)	$ 1,570,356	$ (87,352)	$ 162,272
Weighted average actuarial assumptions used to determine net periodic cost:				
Discount rate	4.16%	4.55%	4.70%	4.10%
Expected long term return on plan	7.50%	7.50%	N/A	N/A
Compensation rate increase	4.00%	4.00%	N/A	N/A

KEPCo estimates they will amortize the following amounts from regulatory assets into net periodic cost in 2014:

	Pension Benefits	Postretirement Benefits
Actuarial loss	$ 381,287	$ 21,062
Prior service cost	7,436	-
Total	$ 388,723	$ 21,062

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:

	2013	2012
Health care cost trend rate assumed for next year	7.50%	8.00%
Rate to which the cost trend rate is assumed to decline	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2019	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	(1,177)	1,208
Effect on post-retirement benefit obligation	(13,002)	12,354

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

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, 2013 and 2012:

		Fair Value Measurements Using		
December 31, 2013	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	$ 52,886	$ -	$ 52,886	$ -
Equity securities				
U.S.	3,906,209	-	3,906,209	-
International	4,706,569	-	4,706,569	-
Debt securities				
Core bonds	3,437,348	-	3,437,348	-
Commodities	669,611	-	669,611	-
Alternative investments	529,374	-	-	529,374
Real estate	1,344,827	-	694,486	650,341
Total	$ 14,646,824	$ -	$ 13,467,109	$ 1,179,715

		Fair Value Measurements Using		
December 31, 2012	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	$ 37,956	$ -	$ 37,956	$ -
Equity securities				
U.S. companies	3,102,797	-	3,102,797	-
International companies	3,891,671	-	3,891,671	-
Debt securities				
Core bonds	3,161,175	-	3,161,175	-
Commodities	611,305	-	611,305	-
Alternative investments	497,891	-	-	497,891
Real estate	1,214,360	-	634,695	579,665
Total	$ 12,517,155	$ -	$ 11,439,599	$ 1,077,556

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, 2013 and 2012:

	Real Estate Securities	Alternative Investments
Balance at January 1, 2013	$ 579,665	$ 497,891
Actual return on plan assets		
Relating to assets still held at the reporting date	70,676	31,483
Balance at December 31, 2013	$ 650,341	$ 529,374
Balance at January 1, 2012	$ 463,355	$ -
Actual return on plan assets		
Relating to assets still held at the reporting date	(52,517)	2,891
Relating to assets sold during the year	96,384	-
Purchases, sales, and settlements	72,443	495,000
Balance at December 31, 2012	$ 579,665	$ 497,891

Estimated future benefit payments as of December 31, 2013, for the Plans, which reflect expected future services, are as follows:

	Pension Benefits		Postretirement Benefits	
	To/from trust	From company assets	To/from trust	From company assets
Expected contributions:				
2014	$ -	$ -	$ 80,322	$ -
Expected benefit payments:				
2014	$ 554,193	$ 31,024	$ 82,312	$ -
2015	649,227	31,060	89,656	-
2016	750,917	31,119	95,774	-
2017	857,653	31,253	101,883	-
2018	968,597	31,437	107,906	-
2019-2023	6,598,856	161,416	561,212	-

(11) 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 the Cooperative'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 Committee in the amount of $1,500,000 which matures March 23, 2014. 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 was reauthorized through December 31, 2025 by the Energy Policy Act of 2005, KEPCo is required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently approximately $13.6 billion. This limit of liability consists of the maximum available commercial insurance of $375 million, and the remaining $13.2 billion is provided through mandatory participation in an industry wide retrospective assessment program. Under this retrospective assessment program, owners are jointly and severally subject to an assessment of up to $127.3 million ($7.64 million - KEPCo's share) at any commercial reactor in the country, payable at no more than $19 million ($1.14 million - KEPCo's share) 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 decommissioning liability and property damage insurance for Wolf Creek totaling approximately $2.8 billion ($168 million KEPCo's 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 Nuclear Regulatory Commission. KEPCo's share of any remaining proceeds can be used to pay for property damage or, if certain requirements are met, including nuclear 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, KEPCo may be subject to retrospective assessments under the current policies of approximately $2.06 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 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 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, 2013, KEPCo's share of WCNOC's nuclear fuel commitments was approximately $5.3 million for uranium concentrates expiring in 2017, $0.8 million for conversion expiring in 2017, $13.9 million for enrichment expiring at various times through 2045 and $5.3 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.

(12) 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, 2013:

		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	$17,844,344	$17,844,344	$ -	$ -

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, 2013 and 2012:

	December 31, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Cash and cash equivalents	$ 5,181,544	$ 5,181,544	$ 2,824,134	$ 2,824,134
Bond fund reserve	4,465,868	4,579,181	4,439,704	4,607,690
Financial liabilities:				
Long-term debt	$ 162,953,975	$ 170,011,842	$ 169,139,737	$ 189,582,020

(13) 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. 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 2013 and 2012.

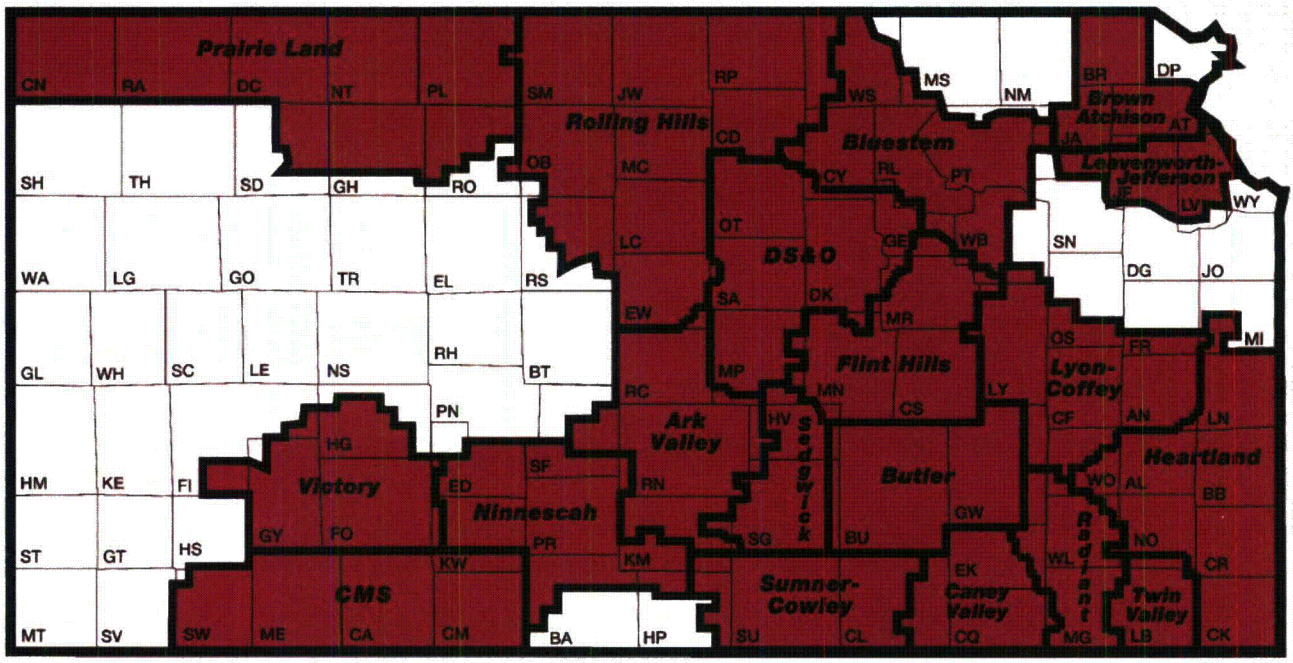
(14) Subsequent Events

The Company has evaluated subsequent events through April 3, 2014, 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

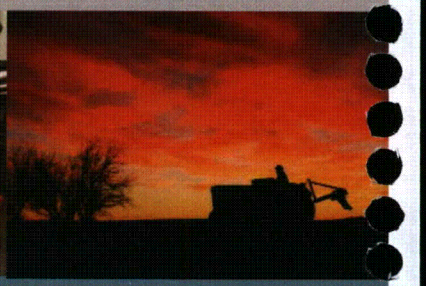
KEPCo exists on behalf of its Members to produce, procure, transmit, deliver and maintain a reliable supply of wholesale electricity within financial guidelines and risk tolerances established by the Board.

KEPCo Member Area 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.

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