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, 2012

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. [ ]

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 $3,780,404,248 at June 30, 2012.

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	126,779,907 shares
(Class)	(Outstanding at February 19, 2013)

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 2013 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
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
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
OTC	Over-the-counter
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,
- 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 ability of our counterparties to make payments as and when due and to perform as required,
- the existence or introduction of competition into markets in which we operate,
- the impact of frequently changing laws and regulations relating to air 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 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,
- regulatory limits, higher costs and/or reduced demand associated with coal-based energy because of concerns about environmental impact or the desire to advance alternate energy sources,

- conservation and energy efficiency measures which may reduce electricity sales,
- 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 690,000 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. We strive to optimize flexibility in our planning and operations to be able to respond to uncertain and changing conditions. 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 to help customers use energy more efficiently.

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, purchase or exchange 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,		
	2012	2011	2010
Residential	32%	32%	32%
Commercial	28%	28%	28%
Industrial	16%	16%	16%
Wholesale	14%	16%	16%
Transmission	9%	7%	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,		
	2012	2011	2010
Residential	34%	35%	35%
Commercial	38%	37%	38%
Industrial	28%	28%	27%
Total	100%	100%	100%

Generation Capacity

We have 6,557 megawatts (MW) of accredited generating capacity in service. See "Item 2. Properties" for additional information about our generating units. While we own wind generation facilities with an installed design capacity of 149 MW, the intermittent nature of this type of production does not create any appreciable amount of accredited capacity as evidenced by the 1 MW of capacity provided in the table below. 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	3,425	53%	18,690,690	74%
Nuclear	547	8%	3,893,910	15%
Natural gas/diesel	2,584	39%	2,237,640	9%
Wind	1	<1%	438,045	2%
Total	6,557	100%	25,260,285	100%

In addition to owning and leasing the generating capacity identified in the table above, we also have agreements under which we purchase wind generation from facilities with installed design capacities totaling approximately 515 MW. In 2012, we purchased 760,807 megawatt hours (MWh) of energy under these agreements. The installed design capacity of wind generation that we own and from which we purchase totals 664 MW; which reflects about 9% of our total generating capacity.

Our aggregate 2012 peak system net load of 5,411 MW occurred on July 25, 2012. Our net generating capacity, combined with firm capacity purchases and sales and potentially interruptible load, provided a capacity margin of 18% above system peak responsibility at the time of our 2012 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
ONEOK Energy Services Co.	75	December 2015
Midwest Energy, Inc.	120	May 2016
Midwest Energy, Inc.	35	May 2017
Mid-Kansas Electric Company, LLC	174	January 2019
Kansas Power Pool	50	March 2020
Midwest Energy, Inc.	150	May 2025
Other	13	December 2013 – May 2015
Total	678	

(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 2012, we provided approximately 88 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. In addition, the agreement for the city to provide capacity to us is treated as a capital lease. See Note 18 of the Notes to Consolidated Financial Statements, "Leases," for additional information.

Generation Mix

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).

Based on MMBtu, our 2012 fuel mix was 76% coal, 15% nuclear and 9% natural gas, with diesel making up less than 1%. Our generation mix fluctuates with the operation of Wolf Creek, variations in fuel costs, plant availability, customer demand, and the cost and availability of power in the wholesale market.

Fossil Fuel Generation

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 delivery 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, 2013, 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. We expect increases in the cost of transporting coal due to higher prices for the items subject to contractual escalation.

The average delivered cost of coal consumed at JEC during 2012 was approximately $1.77 per MMBtu, or $29.24 per ton.

La Cygne Generating Station (La Cygne): The two coal-fired units at La Cygne have an aggregate generating capacity of 1,422 MW, of which we own or consolidate through a VIE a 50% share, or 711 MW. La Cygne uses primarily PRB coal but one of the two units mixes 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 100%, 70% and 20% of La Cygne's PRB coal requirements are under contract for 2013, 2014 and 2015, respectively. About 90% of those commitments are fixed price contracts. 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 2013 and Kansas City Southern Railroad through 2020. During 2012, our share of average delivered cost of coal consumed at La Cygne was approximately $2.04 per MMBtu, or $35.39 per ton.

Lawrence and Tecumseh Energy Centers: Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 731 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 2013, at which time we plan to enter into a new contract.

During 2012, the average delivered cost of coal consumed in the Lawrence units was approximately $1.92 per MMBtu, or $34.00 per ton. The average delivered cost of coal consumed in the Tecumseh units was approximately $1.88 per MMBtu, or $33.60 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 2012, we consumed 23.4 million MMBtu of natural gas for a total cost of $75.0 million, or approximately $3.20 per MMBtu. Natural gas accounted for approximately 9% of the total MMBtu of fuel we consumed and approximately 15% of our total fuel expense in 2012. From time to time, we may enter into contracts, including the use of derivatives, in an effort to manage the overall 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 June 24, 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 No. 2 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 No. 2 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 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 equal to their respective ownership in Wolf Creek and pay fuel costs generally equal to the amount of power they take from the plant, which is normally about equal 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 January 2015 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

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

Wolf Creek normally operates on an 18-month planned refueling and maintenance outage schedule. However, as a result of an extended unscheduled outage in 2012 and resulting fuel remaining, Wolf Creek was able to defer its next refueling and maintenance outage until the first quarter of 2013. 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, 2012, we owned approximately 149 MW of designed installed wind capacity and had under contract the purchase of wind energy produced from approximately 515 MW of designed installed wind capacity.

Other Fuel Matters

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

	2012	2011	2010
Per MMBtu:			
Nuclear	$ 0.70	$ 0.68	$ 0.63
Coal	1.86	1.74	1.56
Natural gas	3.20	4.81	5.12
Diesel	23.12	19.33	15.76
All generating stations	1.84	1.92	1.70
Per MWh Generation:			
Nuclear	$ 7.28	$ 7.15	$ 6.50
Coal	20.59	19.30	17.45
Natural gas/diesel	33.29	52.65	56.37
All generating stations	19.65	20.60	18.37

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 make such purchases 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 2012, purchased power comprised approximately 18% of our total fuel and purchased power expense. Our weighted average cost of purchased power per MWh was $26.41 in 2012, $34.27 in 2011 and $36.23 in 2010.

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.

Real-Time Energy Imbalance Market

The SPP currently utilizes a real-time energy imbalance market to accommodate financial settlement of energy imbalances within the SPP region. The objective of the real-time market is to permit an efficient balancing of energy production and consumption through the use of a least-cost economic dispatch system. It also provides a ready market for the purchase and sale of electricity to balance production with demand. We are an active participant in this market.

Developing Forward Market in SPP

The SPP is developing an integrated market similar to some neighboring RTOs. The goal of the SPP integrated market is to reduce the overall production cost for the SPP region. The new market is expected to begin in March 2014. We expect it to change the way our plants are dispatched.

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 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 generating facilities, including sulfur dioxide (SO_2), particulate matter (PM), nitrogen oxides (NOx), carbon monoxide (CO), mercury and acid gases.

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

Sulfur Dioxide and Nitrogen Oxide

Through the combustion of fossil fuels at our generating facilities, we emit SO_2 and NOx. Federal and state laws and regulations, including those noted above, and permits issued to us limit the amount of these substances we can emit. If we exceed these limits we could be subject to fines and penalties. In order to meet SO_2 and NOx regulations applicable to our generating facilities, we use low-sulfur coal and natural gas and have equipped 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, the EPA allocates annual SO_2 emissions allowances to emitting units subject to the program. Each unit must have enough allowances to cover its SO_2 emissions for that year. Allowances are tradable so that operators of affected units that are anticipated to emit SO_2 in excess of their allowances may purchase additional allowances from others. In 2012, we had SO_2 allowances adequate to meet planned generation and we expect to have enough to cover emissions under this program in 2013.

Cross-State Air Pollution Rule

In mid 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. Under CSAPR, reductions in annual SO_2 and NOx emissions were required to begin January 2012, with further reductions required beginning January 2014. The EPA also published a final supplemental rule to CSAPR later in 2011 requiring five states, including Missouri and Oklahoma, to make summertime reductions in NOx emissions beginning in May 2012. Although Kansas was included in the original proposed rule, the final supplemental rule instead called for the EPA to revisit Kansas' status once Kansas submitted an ozone state implementation plan. 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. In October 2012, the EPA filed a petition with the court requesting a rehearing before the full court. In January 2013, the court issued orders declining to rehear the case. We cannot at this time predict how the EPA may proceed with rulemaking; 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 PM, NOx, 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 PM. The EPA anticipates making initial attainment/nonattainment designations under this rule by the end of 2014. 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. 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.

The EPA is required to review the NAAQS for ozone in 2013 and is likely to propose a more stringent standard.

Mercury and Other Air Emissions

The operation of power plants results in emissions of mercury, acid gases and other air toxics. In 2011, the EPA finalized Mercury and Air Toxics Standards (MATS) for power plants, which replaces the prior federal Clean Air Mercury Rule and requires significant reductions in emissions of mercury, acid gases and other emissions. Companies impacted by the new standards will have up to three, or four years with approval from a state environmental regulatory agency, and in certain limited circumstances up to five years, to comply. We have obtained approval from our state environmental regulatory agency and expect to be compliant with the new standards within four years. We continue to evaluate the new standards and believe that our related investment will be less than $16.0 million.

Greenhouse Gases

One byproduct of burning coal and other fossil fuels is the emission of carbon dioxide (CO_2) and other gases referred to as greenhouse gases (GHGs), which are believed by many to contribute to climate change. Legislators, including the U.S. Congress, have at times considered the passage of laws to limit the emission of CO_2 and other GHGs. It is possible that federal legislation related to GHG emissions will be considered, and promulgated, by legislators in the next few years. The EPA has also 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 March 2012, the EPA proposed a New Source Performance Standard (NSPS) that would limit CO_2 emissions for new and modified electric generating units. We are currently evaluating the proposal and believe it could impact our future generation plans if it becomes a final rule. The EPA has indicated that a final rule could be issued in 2013. The EPA is also expected to propose a GHG NSPS for existing generating units. We cannot at this time determine the impact of such a performance standard 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 is regulating 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 costs to comply 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. The EPA delayed its plans to propose revisions to the rules governing such discharges from coal-fired power plants to 2013 with final action on the proposed rules expected to occur in 2014. Although we cannot at this time determine the timing or impact of 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 set stricter technology standards 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 expected to finalize the rule in 2013; 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.

Because Kansas is in a severe drought and water remains a critical resource to our business, as well as the State economy, we have increased our attention to water quantity matters. We will continue to refine our contingency plans should the drought persist.

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, 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 is expected to issue a final rule in 2014 or sooner. 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 capacity must be 10% of the average peak 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 and contribute toward meeting the increased requirements beginning in 2016. 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 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 our approximately $610.0 million share of the costs associated with the $1.2 billion of environmental upgrades at La Cygne. We therefore must file for a general review of our rates or an abbreviated rate review with the KCC in order to collect these costs, which increases the time between making these investments and having them reflected in the prices we charge our customers, as well as the amount we charge our customers. We plan to file an abbreviated rate review in April 2013 for recovery of our capital investment of approximately $350.0 million of our share of the La Cygne environmental upgrades.

Our estimated capital expenditures associated with environmental improvements for 2013-2015 appear in the following table. We prepare these estimates for planning purposes and revise them from time to time.

Year	Total
	(In Thousands)
2013	$ 311,200
2014	239,500
2015	92,600
Total	$ 643,300

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 $240.0 million. The settlement also required that we determine whether we needed to install additional SCR equipment on another JEC unit or if we can meet agreed upon plant-wide NOx emissions reduction limits using other controls. We have informed the EPA that we believe we can meet the terms of the settlement by installing less expensive NOx reduction equipment rather than additional SCR equipment. 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, whose purpose is to protect the safety and health of workers. 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 19, 2013, we had 2,313 employees, 1,269 of which were covered by a contract with Locals 304 and 1523 of the International Brotherhood of Electrical Workers that extends through June 30, 2013.

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	51	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)
James J. Ludwig	54	Executive Vice President, Public Affairs and Consumer Services (since July 2007)	
Douglas R. Sterbenz	49	Executive Vice President and Chief Operating Officer (since July 2007)	
Greg A. Greenwood	47	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	49	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)
Jeffrey L. Beasley	54	Vice President, Corporate Compliance and Internal Audit (since September 2007)	
Larry D. Irick	56	Vice President, General Counsel and Corporate Secretary (since February 2003)	
Lee Wages	64	Vice President, Controller (since December 2001)	

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 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 March 2012, the EPA proposed an NSPS that would limit CO_2 emissions for new and modified electric generating units. This proposal is expected to become a final rule in 2013. 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 the future 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 is expected to issue a final rule in 2014 or sooner. 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 shutdown 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. Actual future demand and our ability to satisfy such demand depends 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 2013 through 2015 are approximately $2.3 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 affects 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, upon which we plan to meet 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, propriety 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Name	Location	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) By Owner		
					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	150	—	150
Hutchinson Energy Center:	Hutchinson, Kansas						
Steam Turbine		4	1965	Gas	160	—	160
Combustion Turbines		1	1974	Gas	54	—	54
		2	1974	Gas	52	—	52
		3	1974	Gas	55	—	55
		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	—	343	343
Lawrence Energy Center:	Lawrence, Kansas						
Steam Turbines		3	1954	Coal	51	—	51
		4	1960	Coal	109	—	109
		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	66	—	66
		4 (d)	2001	Gas	67	—	67
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	70	—	70
		8	1962	Coal	127	—	127
Wolf Creek Generating Station (47%):	Burlington, Kansas						
Nuclear		1 (b)	1985	Uranium	—	547	547
Total					4,076	2,481	6,557

(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 4,600 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

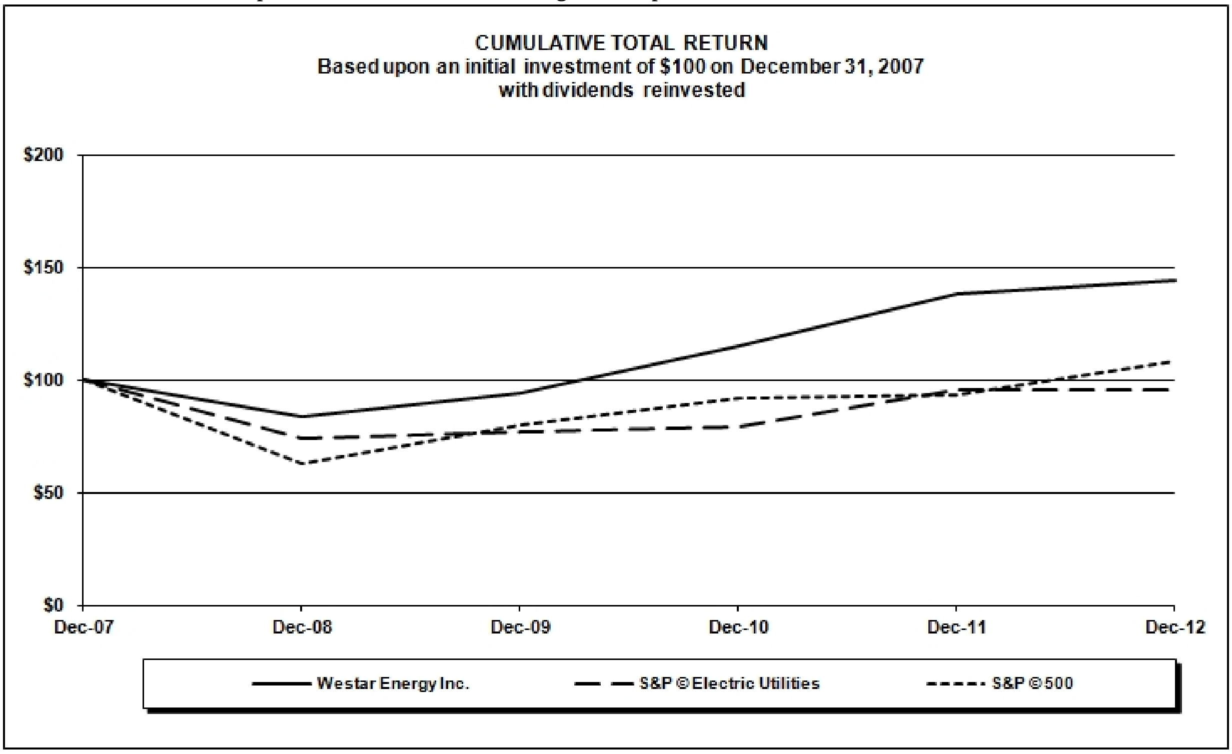
ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

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 19, 2013, Westar Energy had 20,347 common shareholders of record. For information regarding quarterly common stock price ranges for 2012 and 2011, 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, 2007, and ended on December 31, 2012, 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.



	Dec 2007	Dec 2008	Dec 2009	Dec 2010	Dec 2011	Dec 2012
Westar Energy Inc.	$100	$83	$94	$115	$138	$144
S&P© 500	$100	$63	$80	$92	$94	$109
S&P© Electric Utilities	$100	$74	$77	$79	$96	$95

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 2012, Westar Energy's board of directors declared four quarterly dividends of $0.33 per share, reflecting an annual dividend of $1.32 per share, compared to four quarterly dividends of $0.32 per share in 2011, reflecting an annual dividend of $1.28 per share. On February 28, 2013, Westar Energy's board of directors declared a quarterly dividend of $0.34 per share payable to shareholders on April 1, 2013. The indicated annual dividend rate is $1.36 per share.

UNREGISTERED SALES OF EQUITY SECURITIES

In addition to information included in our Form 10-Q filed on November 8, 2012, during the three-month period ended December 31, 2012, Westar Energy entered into forward transactions pursuant to the forward sale agreement dated April 2, 2010, between Westar Energy and The Bank of New York Mellon (filed as Exhibit 10.1 to the Form 8-K filed on April 2, 2010) and the Sales Agency Financing Agreement with BNY Mellon Capital Markets, LLC and The Bank of New York Mellon (filed as Exhibit 1.3 to the Form S-3 filed on April 2, 2010), as amended on May 26, 2010 (filed as Exhibit 1(a) to the Form 10-Q filed on August 7, 2012), and May 9, 2012 (filed as Exhibit 1(b) to the Form 10-Q filed on May 9, 2012), in respect to an aggregate of approximately 0.4 million shares of Westar Energy common stock.

In connection with the forward transactions, Westar Energy did not receive any proceeds from the sale of borrowed shares of its common stock by BNY Mellon Capital Markets, LLC. Westar Energy expects to receive proceeds from the sale of such shares, subject to certain adjustments, upon future physical settlement(s) of the forward transactions pursuant to the terms of the forward sale agreement. If Westar Energy elects to cash settle or net share settle the forward transactions, it may not receive any proceeds (in the case of cash settlement) or shares of its common stock (in the case of net share settlement) pursuant to the terms of the forward sale agreement.

The forward transactions were entered into pursuant to the terms of a letter dated October 6, 2003, submitted by Robert W. Reeder and Leslie N. Silverman to Paula Dubberly of the staff of the Securities and Exchange Commission (Staff), to which the Staff responded in an interpretive letter dated October 9, 2003. As required by such letter, the shares of Westar Energy common stock sold by BNY Mellon Capital markets, LLC to hedge the forward transaction were sold pursuant to an effective Westar Energy registration statement (registration No. 333-165889), which was filed on April 2, 2010.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(In Thousands)				
Income Statement Data:					
Total revenues	$ 2,261,470	$ 2,170,991	$ 2,056,171	$ 1,858,231	$ 1,838,996
Net income (a)	282,462	236,180	208,624	141,330	178,140
Net income attributable to common stock	273,530	229,269	202,926	174,105	177,170

	As of December 31,				
	2012	2011	2010	2009	2008
	(In Thousands)				
Balance Sheet Data:					
Total assets	$ 9,265,231	$ 8,682,851	$ 8,079,638	$ 7,525,483	$ 7,443,259
Long-term obligations (b)	3,124,831	2,818,030	2,808,560	2,610,315	2,465,968

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Common Stock Data:					
Basic earnings per share available for common stock (c)	$ 2.15	$ 1.95	$ 1.81	$ 1.58	$ 1.69
Dividends declared per share	$ 1.32	$ 1.28	$ 1.24	$ 1.20	$ 1.16
Book value per share	$ 22.89	$ 22.03	$ 21.25	$ 20.59	$ 20.18
Average equivalent common shares outstanding (in thousands) (d) (e) (f)	126,712	116,891	111,629	109,648	103,958

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(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 2012, 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) The earnings per share (EPS) amount previously reported for 2008 was adjusted to reflect the use of the two-class method beginning in 2009. 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. Additionally, we recorded basic EPS available for common stock from continuing operations of $1.28 in 2009.
(d) In 2008, Westar Energy issued and sold approximately 12.8 million shares of common stock realizing proceeds of $293.6 million.
(e) In 2010, Westar Energy issued and sold approximately 3.1 million shares of common stock realizing proceeds of $54.7 million.
(f) 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.

EXECUTIVE SUMMARY

Description of Business

We are the largest electric utility in Kansas. We produce, transmit and sell electricity at retail to approximately 690,000 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, purchase or exchange 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, 2012 and 2011.

	Year Ended December 31,		
	2012	2011	Change
	(Dollars In Thousands, Except Per Share Amounts)		
Net income attributable to common stock	$ 273,530	$ 229,269	$ 44,261
Earnings per common share, basic	2.15	1.95	0.20

Net income attributable to common stock increased due primarily to higher retail prices, reduced depreciation expense and our having recorded an additional $17.4 million in corporate-owned life insurance (COLI) benefits. These items were offset partially by increases in some operating costs, as authorized in the April 2012 KCC order, and our having recorded a $7.2 million gain on the sale of a non-utility investment in 2011. Contributing to the higher operating costs was our having reversed $22.0 million of previously accrued liabilities in 2011 as a result of settling litigation. See the discussion under "—Operating Results" below for additional information. In addition, basic EPS was impacted by our having had more average equivalent common shares outstanding in 2012 due primarily to the issuance of additional shares in the latter part of 2011 to settle forward sale transactions.

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 networks;
- 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. We strive to optimize flexibility in our planning and operations to be able to respond to uncertain and changing conditions. 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 to help customers use energy more efficiently.

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 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 2011, the EPA published MATS for power plants, which replaces the prior federal CAMR and requires significant reductions in mercury, acid gases and other emissions. Companies impacted by the new standards will have up to three years, or four years with approval from a state environmental regulatory agency, and in certain limited circumstances up to five years, to comply. We have obtained approval from our state environmental regulatory agency and expect to be compliant with the new standards within four years. We continue to evaluate the new standards and believe that our related investment will be less than $16.0 million.

In mid 2011, the EPA finalized CSAPR requiring 28 states, including Kansas, Missouri and Oklahoma, to further reduce power plant emissions of SO_2 and NOx. Under CSAPR, reductions in annual SO_2 and NOx emissions were required to begin January 2012, with further reductions required beginning January 2014. The EPA also published a final supplemental rule to CSAPR later in 2011 requiring five states, including Missouri and Oklahoma, to make summertime reductions in NOx emissions beginning in May 2012. Although Kansas was included in the original proposed rule, the final supplemental rule instead called for the EPA to revisit Kansas' status once Kansas submitted an ozone state implementation plan. 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. In October 2012, the EPA filed a petition with the court requesting a rehearing before the full court. In January 2013, the court issued orders declining to rehear the case. We cannot at this time predict how the EPA may proceed with rulemaking; 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.

Greenhouse Gases

In March 2012, the EPA proposed an NSPS that would limit CO_2 emissions for new and modified electric generating units. We are currently evaluating the proposal and believe it could impact our future generation plans if it becomes a final rule. The EPA has indicated that a final rule could be issued in 2013. The EPA is also expected to propose a GHG NSPS for existing generating units. We cannot at this time determine the impact of such a performance standard 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 is regulating 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 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, 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 is expected to issue a final rule in 2014 or sooner. 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 PM, NOx, 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 reveiwed 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 December 2012, the EPA strengthened an existing NAAQS for PM. The EPA anticipates making initial attainment/nonattainment designations under this rule by the end of 2014. 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. 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.

The EPA is required to review the NAAQS for ozone in 2013 and is likely to propose a more stringent standard.

Water

We discharge some of the water used in our operations. This water may contain substances deemed to be pollutants. The EPA delayed its plans to propose revisions to the rules governing such discharges from coal-fired power plants to 2013 with final action on the proposed rules expected to occur in 2014. Although we cannot at this time determine the timing or impact of 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 set stricter technology standards 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 expected to finalize the rule in 2013; 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.

Since Kansas is in a severe drought and water remains a critical resource to our business, as well as the State economy, we have increased our attention to water quantity matters. We will continue to refine our contingency plans should the drought persist.

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 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 and contribute toward meeting the increased requirements beginning in 2016. 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.

In January 2012, Wolf Creek experienced a loss of off-site power that resulted in an unscheduled outage, with the plant returning to normal operations in March 2012. The NRC increased its oversight of Wolf Creek following the loss of off-site power. 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

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,		
	2012	2011	2010
	(In Thousands)		
Borrowed funds	$ 10,399	$ 5,589	$ 4,295
Equity funds	11,706	5,550	3,104
Total	$ 22,105	$ 11,139	$ 7,399
Average AFUDC Rates	5.0%	3.6%	2.6%

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 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.

Outstanding Shares of Common Stock

We expect the number of outstanding shares of Westar Energy common stock to increase over the next several years as we issue additional shares 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 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.

2013 Outlook

In 2013, we expect to maintain our current business strategy and regulatory approach. Subject to regulatory approvals, we anticipate price increases in the form of formulae that track changes in certain of our costs. We plan to file an abbreviated rate review in April 2013 for recovery of capital costs associated with approximately $350.0 million of our share of the La Cygne environmental upgrades. Assuming normal weather in line with the historical average, we expect 2013 retail electricity sales to be about 1% higher than weather normalized 2012 sales driven primarily by increased industrial demand.

In addition, we anticipate increased operating and maintenance expenses, including maintenance costs for our power plants, and higher selling, general and administrative expenses, some of which will be offset in revenues. We plan to contribute $46.0 million to the Westar Energy and Wolf Creek pension and post-retirement benefit plans in 2013. To help fund our capital spending as provided under "—Future Cash Requirements" below, we plan to issue long-term debt in addition to utilizing short-term borrowings and we expect to issue common stock to settle forward sale transactions.

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, 2012, we had recorded regulatory assets currently subject to recovery in future prices of approximately $1.0 billion and regulatory liabilities of $323.2 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	$ 85,050	$ 8,067
	0.5% increase	(78,952)	(7,806)
Salary scale	0.5% decrease	(19,342)	(3,754)
	0.5% increase	19,704	3,870
Rate of return on plan assets	0.5% decrease	—	3,062
	0.5% increase	—	(3,063)

(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	$ 8,856	$ 367
	0.5% increase	(8,402)	(385)
Rate of return on plan assets	0.5% decrease	—	502
	0.5% increase	—	(500)
Annual medical trend	1.0% decrease	(1,256)	(149)
	1.0% increase	1,360	160

(a) Increases or decreases due to changes in actuarial assumptions result primarily in changes to regulatory assets and liabilities.

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 carry forward into future periods capital losses, operating losses and tax credits. 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, 2012 and 2011, we have recorded AROs of $152.6 million and $142.5 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, 2012 and 2011, we had $129.0 million and $82.3 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 sales based on prevailing market prices generally serve to offset our retail prices and the prices charged to certain wholesale customers taking service under cost-based tariffs.

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 energy marketing transactions unrelated to the production of our generating assets, changes in valuations of related contracts and fees we earn for marketing 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 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.

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)
Operating and maintenance	612,871	557,752	55,119	9.9
Depreciation and amortization	270,464	285,322	(14,858)	(5.2)
Selling, general and administrative	226,012	184,695	41,317	22.4
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	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

(a) Reflects revenue from an SPP network transmission tariff. In 2012 and 2011, our SPP network transmission costs were $166.5 million and $132.2 million, respectively. These amounts, less administration costs of $27.2 million and $18.6 million, were returned to us as revenue in 2012 and 2011, respectively.
(b) Change greater than 1000%.

Rate Case Agreement

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 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. For this reason, 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 less the sum of fuel and purchased power costs and SPP network transmission costs. Transmission costs reflect the costs of providing network transmission service. Accordingly, in calculating gross margin, we recognize the net value of this transmission activity as shown in the table immediately following. However, we record transmission costs as operating and maintenance expense on our consolidated statements of income. 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.

Income from operations is the most directly comparable measure GAAP measure to our presentation of gross margin. 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, 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
Add: SPP network transmission costs	166,547	132,164	34,383	26.0
Less: Operating and maintenance expense	612,871	557,752	55,119	9.9
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
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	$ 612,871	$ 557,752	$ 55,119	9.9

Operating and maintenance expense increased due principally to:

- higher SPP network transmission costs of $34.4 million, most of which is offset with higher revenues;
- a $9.2 million increase in property taxes, most of which is offset in retail revenues;
- higher costs for tree trimming 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;
- 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)			
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 these items 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 our share of the earnings of the 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 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.

2011 Compared to 2010

Below we discuss our operating results for the year ended December 31, 2011, compared to the results for the year ended December 31, 2010. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 693,388	$ 661,177	$ 32,211	4.9
Commercial	604,626	572,062	32,564	5.7
Industrial	347,881	318,249	29,632	9.3
Other retail	(8,964)	(12,703)	3,739	29.4
Total Retail Revenues	1,636,931	1,538,785	98,146	6.4
Wholesale	346,948	334,669	12,279	3.7
Transmission (a)	154,569	144,513	10,056	7.0
Other	32,543	38,204	(5,661)	(14.8)
Total Revenues	2,170,991	2,056,171	114,820	5.6
OPERATING EXPENSES:				
Fuel and purchased power	630,793	583,361	47,432	8.1
Operating and maintenance	557,752	520,409	37,343	7.2
Depreciation and amortization	285,322	271,937	13,385	4.9
Selling, general and administrative	184,695	207,607	(22,912)	(11.0)
Total Operating Expenses	1,658,562	1,583,314	75,248	4.8
INCOME FROM OPERATIONS	512,429	472,857	39,572	8.4
OTHER INCOME (EXPENSE):				
Investment earnings	9,301	7,026	2,275	32.4
Other income	8,652	5,369	3,283	61.1
Other expense	(18,398)	(16,655)	(1,743)	(10.5)
Total Other Expense	(445)	(4,260)	3,815	89.6
Interest expense	172,460	174,941	(2,481)	(1.4)
INCOME BEFORE INCOME TAXES	339,524	293,656	45,868	15.6
Income tax expense	103,344	85,032	18,312	21.5
NET INCOME	236,180	208,624	27,556	13.2
Less: Net income attributable to noncontrolling interests	5,941	4,728	1,213	25.7
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY	230,239	203,896	26,343	12.9
Preferred dividends	970	970	—	—
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 229,269	$ 202,926	$ 26,343	13.0
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY	$ 1.95	$ 1.81	$ 0.14	7.7

(a) Reflects revenue from an SPP network transmission tariff. In 2011 and 2010, our SPP network transmission costs were $132.2 million and $116.4 million, respectively. These amounts, less administration costs of $18.6 million and $14.4 million, respectively, were returned to us as revenue.
(b) Cannot divide by zero.

Gross Margin

The following table summarizes our gross margin for the years ended December 31, 2011 and 2010.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars In Thousands)			
Revenues	2,170,991	2,056,171	114,820	5.6
Less: Fuel and purchased power expense	630,793	583,361	47,432	8.1
SPP network transmission costs	132,164	116,449	15,715	13.5
Gross Margin	$ 1,408,034	$ 1,356,361	$ 51,673	3.8

The following table reflects changes in electricity sales for the years ended December 31, 2011 and 2010. 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,			
	2011	2010	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,986	6,957	29	0.4
Commercial	7,573	7,519	54	0.7
Industrial	5,589	5,468	121	2.2
Other retail	88	89	(1)	(1.1)
Total Retail	20,236	20,033	203	1.0
Wholesale	8,215	8,712	(497)	(5.7)
Total	28,451	28,745	(294)	(1.0)

Gross margin increased due primarily to higher total retail revenues, 84% of which was due to higher prices and 16% of which was due to higher electricity sales. The increase in retail electricity sales was due principally to higher industrial electricity sales. We believe improving economic conditions are why some of our industrial customers experienced increased production, which resulted in more electricity sales to them. Residential and commercial electricity sales increased due primarily to the effects of warmer weather. As measured by cooling degree days, the weather in 2011 was 7% warmer than in 2010.

The following table reconciles income from operations with gross margin for the years ended December 31, 2011 and 2010.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars In Thousands)			
Gross margin	$ 1,408,034	$ 1,356,361	$ 51,673	3.8
Add: SPP network transmission costs	132,164	116,449	15,715	13.5
Less: Operating and maintenance expense	557,752	520,409	37,343	7.2
Depreciation and amortization expense	285,322	271,937	13,385	4.9
Selling, general and administrative expense	184,695	207,607	(22,912)	(11.0)
Income from operations	$ 512,429	$ 472,857	$ 39,572	8.4

Operating Expenses and Other Income and Expense Items

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Operating and maintenance expense	$ 557,752	$ 520,409	$ 37,343	7.2

Operating and maintenance expense increased due principally to:

- higher SPP network transmission costs of $15.7 million, most of which is recovered in revenues;
- higher costs at Wolf Creek of $13.0 million, which was the result primarily of an increase in the amortization of deferred refueling and maintenance outage costs of $8.0 million and higher regulatory compliance costs;
- a $7.0 million increase in property taxes, which was mostly offset in retail revenues;
- our having recorded in 2010 a $5.0 million reduction in our liability for environmental remediation costs associated with assets we divested many years ago;
- a $2.3 million increase related to the operation of our steam powered plants; and
- higher costs for tree trimming and other distribution reliability activities of $1.4 million; however,
- partially offsetting these increases was an $8.0 million decrease in the amortization of previously deferred storm costs.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Depreciation and amortization expense	$ 285,322	$ 271,937	$ 13,385	4.9

Depreciation and amortization expense increased as a result of our having recorded additional depreciation expense associated primarily with the addition of transmission facilities and additions at our power plants, including air quality controls.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Selling, general and administrative expense	$ 184,695	$ 207,607	$ (22,912)	(11.0)

Selling, general and administrative expense decreased due primarily to:

- the reversal of approximately $22.0 million of previously accrued liabilities as a result of the legal settlements discussed in Note 15 of the Notes to Consolidated Financial Statements, "Legal Proceedings"; and
- our having recorded $7.1 million less for non-union, non-executive employee compensation that is at-risk to employees and payable only upon meeting pre-established operating and financial objectives.

Partially offsetting the aforementioned decreases was:

- a $3.6 million increase in the amortization of previously deferred amounts associated with various energy efficiency programs, which we recover in higher retail revenues; and
- higher legal fees of $3.2 million related principally to the legal matters discussed in Note 15 of the Notes to Consolidated Financial Statements, "Legal Proceedings."

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Investment earnings	$ 9,301	$ 7,026	$ 2,275	32.4

Investment earnings increased due principally to our having recorded a $7.2 million gain on the sale of a non-utility investment. This increase was offset partially by our having recorded lower gains on investments held in a trust to fund retirement benefits. We recorded gains on these investments of $0.8 million in 2011 compared to gains of $4.8 million recorded in 2010.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Other income	$ 8,652	$ 5,369	$ 3,283	61.1

Other income increased due principally to:

- a $2.4 million increase in equity AFUDC, which reflects increased construction activity; and
- our having recorded gains on the sale of oil of $1.2 million, for which similar gains were not recorded in 2010.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Income tax expense	$ 103,344	$ 85,032	$ 18,312	21.5

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, 2012, compared to December 31, 2011.

	As of December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Fuel inventory and supplies	$ 249,016	$ 229,118	$ 19,898	8.7

Fuel inventory and supplies increased due principally to an $11.6 million increase in supplies inventory and a $10.3 million increase in coal inventory. Supplies inventory increased due principally to Wolf Creek's preparation for the 2013 refueling and maintenance outage and as we construct environmental upgrades at Jeffrey Energy Center. As of December 31, 2011, coal volumes were lower due primarily to fewer coal deliveries as a result of flooding in 2011. Coal inventories returned to more normal levels by December 31, 2012.

	As of December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Property, plant and equipment, net	$ 7,013,765	$ 6,411,922	$ 601,843	9.4

Property, plant and equipment, net of accumulated depreciation, increased due primarily to our installation of air quality controls at our power plants and expanding our transmission systems.

	As of December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Regulatory assets	$ 1,002,672	$ 1,046,090	$ (43,418)	(4.2)
Regulatory liabilities	323,175	271,387	51,788	19.1
Net regulatory assets	$ 679,497	$ 774,703	$ (95,206)	(12.3)

Total regulatory assets decreased due primarily to the following reasons:

- an $18.7 million decrease in deferred employee benefit costs;
- a $15.3 million decrease in amounts previously deferred for fuel expense;
- a $14.7 million decrease in previously deferred storm costs; and
- a $10.9 million decrease in amounts deferred for the 2011 Wolf Creek outage; however,
- partially offsetting decreases was a $15.2 million increase in amounts deferred for property taxes.

Regulatory liabilities increased due principally to a $46.6 million increase in amounts collected but not yet spent to dispose of plant assets.

	As of December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Short-term debt	$ 339,200	$ 286,300	$ 52,900	18.5

Short-term debt increased due principally to increased issuances of commercial paper. We used proceeds from issuances of short-term debt securities to fund our capital and ongoing operating needs on an interim basis.

	As of December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Long-term debt, net	$ 2,819,271	$ 2,491,109	$ 328,162	13.2

Long-term debt, net increased due principally to the issuance of $550.0 million principal amount of first mortgage bonds. Partially offsetting this increase was the redemption of $220.5 million of bonds as discussed in Note 9 of the Notes to Consolidated Financial Statements, "Long-term Debt."

	As of December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Deferred income tax liabilities	$ 1,197,837	$ 1,110,463	$ 87,374	7.9

Deferred income tax liabilities increased due primarily to our having recorded $157.5 million of tax benefits resulting from the use of bonus and accelerated depreciation methods. This was partially offset by a state tax credit carryforward benefit of $30.3 million and the tax effect of a deferred net operating loss of $27.5 million.

	As of December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Unamortized investment tax credits	$ 191,512	$ 164,175	$ 27,337	16.7

Unamortized investment tax credits increased due primarily to recording state investment tax credits of $30.3 million in 2012.

	As of December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Accrued employee benefits	$ 564,870	$ 592,617	$ (27,747)	(4.7)

Accrued employee benefits decreased due primarily to our having contributed $56.7 million to the Westar Energy pension trust, our having funded $13.9 million of Wolf Creek's pension plan contributions, and our having contributed $10.8 million to Westar Energy's post-retirement benefit plan and all plans having had favorable returns on assets. Actuarial losses on all plans partially offset decreases.

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. We also use proceeds from the issuance of securities to repay short-term borrowings, which are principally related to investments in capital equipment and the redemption of bonds, when such balances are of sufficient size and it makes economic sense to do so, and for working capital and general corporate purposes. For additional information on our future cash requirements, see "—Future Cash Requirements" below.

In 2013, 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, 2012 and 2011, our capital structure, excluding short-term debt, was as follows:

	As of December 31,	
	2012	2011
Common equity	49%	50%
Preferred stock	—	<1%
Noncontrolling interests	<1%	<1%
Long-term debt, including VIEs	51%	50%

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 described below. 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 19, 2013, Westar Energy had issued $359.7 million of commercial paper.

Westar Energy has two revolving credit facilities in the amounts of $730.0 million and $270.0 million, which terminate in September 2016 and February 2016, respectively. As long as there is no default under the facilities, they may be extended up to an additional two years and one year, respectively, and the aggregate amount of borrowings under the 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 19, 2013, no amounts were borrowed and $15.4 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, 2012, 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.

Debt Financing

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. Proceeds from these issuances of $541.4 million 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.

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. The bonds were redeemed using short-term debt.

As of December 31, 2012, 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, 2012, approximately $830.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

Under the KGE mortgage, the 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, 2012, approximately $870.0 million 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, 2012.

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 2012, Moody's Investors Service (Moody's) upgraded its credit ratings for Westar Energy and KGE first mortgage bonds/senior secured debt to A3 from Baa1. Moody's also upgraded its credit rating for Westar Energy unsecured debt to Baa2 from Baa3 and assigned a P-2 rating to Westar Energy's commercial paper program.

In February 2013, S&P revised its criteria for rating utility first mortgage bonds. As a result S&P upgraded its credit ratings for Westar Energy and KGE first mortgage bonds/senior secured debt to A- from BBB+.

As of February 19, 2013, 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	A3	A3	P-2	Stable
S&P	A-	A-	A-2	Stable
Fitch	A-	A-	F2	Stable

Certain of our derivative instruments contain collateral provisions subject to certain of our debt ratings. If such debt ratings were to decrease or fall below investment grade, the counterparties to the derivative instruments, pursuant to the provisions, could require collateralization on derivative instruments. The aggregate fair value of all derivative instruments with objective credit-risk-related contingent features that were in a liability position as of December 31, 2012 and 2011, was $0.8 million and $3.1 million, respectively, for which we had posted no collateral, including independent amounts, as of either date. If all credit-risk-related contingent features underlying these agreements had been triggered as of December 31, 2012 and 2011, we would have been required to provide to our counterparties $0.1 million and $0.5 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

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, 2012, Westar Energy had 126.5 million shares issued and outstanding.

In April 2010, Westar Energy entered into a three-year Sales Agency Financing Agreement and forward sale agreement with a bank. The maximum amount that Westar Energy may offer and sell under the agreements is 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 may offer and sell shares of its common stock from time to time through the broker dealer subsidiary, as agent. The broker dealer receives 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 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 broker dealer. Westar Energy must settle the forward sale transactions within 18 months of the date each transaction is 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 2012, Westar Energy entered into additional forward sale transactions with respect to an aggregate of approximately 1.8 million shares of common stock. Assuming physical share settlement of these forward sale transactions as of December 31, 2012, Westar Energy would have received aggregate proceeds of approximately $48.1 million based on a forward price of $27.45 per share. Furthermore, Westar Energy entered into an additional forward sale transaction in January 2013 with respect to an aggregate of approximately 0.3 million shares.

In November 2010, Westar Energy entered into a separate forward sale agreement with a bank. Under the terms of the agreement, the bank, as forward seller, borrowed 7.5 million shares of Westar Energy's common stock from third parties and sold them to a group of underwriters for $25.54 per share. Under an over-allotment option included in the agreement, the underwriters purchased approximately 1.0 million additional shares for $25.54 per share, increasing the total number of shares under the forward sale agreement to approximately 8.5 million shares. The underwriters received a commission equal to 3.5% of the sales price of all shares sold under the agreement. In November 2011, Westar Energy delivered approximately 8.5 million shares of common stock for proceeds of approximately $197.3 million as complete settlement of this forward sale agreement.

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 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

Summary of Cash Flows

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Cash flows from (used in):			
Operating activities	$ 599,106	$ 462,696	$ 607,702
Investing activities	(797,337)	(701,516)	(556,045)
Financing activities	200,521	241,431	(54,589)
Net increase (decrease) in cash and cash equivalents	$ 2,290	$ 2,611	$ (2,932)

Cash Flows from Operating Activities

Cash flows from operating activities increased $136.4 million in 2012 compared to 2011 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.

The $145.0 million decrease in 2011 compared to 2010 was due primarily to our having paid $49.8 million more for purchases of coal and natural gas for our power plants, $34.2 million more for the planned Wolf Creek refueling and maintenance outage, $32.2 million more for pension and post-retirement benefit plan contributions, our having received $17.5 million less in income tax refunds in 2011 and our having paid more for maintenance on our power plants and distribution system. In 2011, we also paid former executive officers approximately $47.9 million in compensation and paid approximately $8.4 million for their legal fees and expenses as discussed in Note 15 of the Notes to Consolidated Financial Statements, "Legal Proceedings." Partially offsetting these decreases was our having received approximately $88.7 million more in customer receipts.

Cash Flows used in Investing Activities

Cash flows used in investing activities increased $95.8 million from 2011 to 2012 and $145.5 million from 2010 to 2011 due primarily to our having invested an additional $112.8 million and $157.4 million, respectively, 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. Partially offsetting the increased investment in 2012 was 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 $40.9 million in 2012 compared to 2011 due primarily 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 sale 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.

The $296.0 million increase in 2011 compared to 2010 was due principally to our having received $240.3 million more in proceeds from the issuance of common stock as a result primarily of the settlement of forward sale transactions during 2011. Also contributing to the increase was our having borrowed $54.1 million under a revolving credit facility in 2011 compared to our having repaid $16.1 million of borrowings under the facility in 2010. We used borrowings under the revolving credit facility to fund our capital and ongoing operating needs while the proceeds from the issuance of common stock were used to repay such borrowings as well as for working capital and general corporate purposes. Partially offsetting the aforementioned increases was our having paid $9.1 million more in dividends during 2011, which was attributable to our having increased our common stock dividend from $1.24 per share in 2010 to $1.28 per share in 2011 as well as an increase in common shares outstanding in 2011 due principally to the settlement of forward sale transactions as discussed above.

Future Cash Requirements

Our business requires significant capital investments. Through 2015, 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 2012 and anticipated capital expenditures, including costs of removal, for 2013 through 2015 are shown in the following table.

	Actual 2012	2013	2014	2015
		(In Thousands)		
Generation:				
Replacements and other	$ 146,518	$ 199,600	$ 174,100	$ 169,000
Environmental	354,857	311,200	239,500	92,600
Nuclear fuel	29,582	7,200	52,800	29,100
Transmission (a)	140,236	207,500	167,100	186,000
Distribution	103,466	134,000	128,300	145,200
Other	35,550	28,600	23,500	20,400
Total capital expenditures	$ 810,209	$ 888,100	$ 785,300	$ 642,300

(a) In addition to amounts listed, we are investing in Prairie Wind Transmission. In 2012, we incurred $8.3 million of expenditures related to this investment. In 2013, 2014 and 2015, we plan to incur expenditures related to Prairie Wind Transmission of $4.3 million, $17.9 million and $0.1 million, respectively.

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 frequent and 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, 2012, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2013	$ —	$ 25,942
2014	250,000	27,479
2015	—	27,933
2016	—	28,309
2017	125,000	26,842
Thereafter	2,449,440	111,119
Total maturities	$ 2,824,440	$ 247,624

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 $56.7 million to our pension trust in 2012 and $50.0 million in 2011. We expect to contribute approximately $30.0 million in 2013. In 2012 and 2011, we also funded $13.9 million and $10.0 million, respectively, of Wolf Creek's pension plan contributions. In 2013, we expect to fund $9.4 million of 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 Issuance" above and in Note 16 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock," Westar Energy entered into two separate forward sale agreements in 2010 and completely settled the transactions under one agreement in 2011. 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. For additional information on operating leases, see Note 18 of the Notes to Consolidated Financial Statements, "Leases." See "—Commercial Commitments" below for additional information regarding our letters of credit. We did not have any additional off-balance sheet arrangements as of December 31, 2012.

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, 2012.

	Total	2013	2014 - 2015	2016 - 2017	Thereafter
			(In Thousands)		
Long-term debt (a)	$ 2,824,440	$ —	$ 250,000	$ 125,000	$ 2,449,440
Long-term debt of VIEs (a)	247,624	25,942	55,412	55,151	111,119
Interest on long-term debt (b)	2,312,081	158,069	301,138	282,919	1,569,955
Interest on long-term debt of VIEs	64,100	13,891	22,614	15,776	11,819
Long-term debt, including interest	5,448,245	197,902	629,164	478,846	4,142,333
Pension and post-retirement benefit expected contributions (c)	46,000	46,000	—	—	—
Capital leases (d)	105,336	6,538	12,203	9,795	76,800
Operating leases (e)	70,278	14,453	22,692	15,084	18,049
Other obligations of VIEs (f)	17,403	2,423	2,114	8,310	4,556
Fossil fuel (g)	777,195	235,935	161,409	136,239	243,612
Nuclear fuel (h)	281,232	6,034	57,100	61,463	156,635
Transmission service (i)	34,275	6,039	12,045	6,348	9,843
Unconditional purchase obligations	278,117	159,546	101,844	16,727	—
Total contractual obligations (j)	$ 7,058,081	$ 674,870	$ 998,571	$ 732,812	$ 4,651,828

(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, 2012.
(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 $1.7 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, 2012.

Commercial Commitments

Our commercial commitments as of December 31, 2012, consist of outstanding letters of credit that expire in 2013, some of which automatically renew annually. The letters of credit are comprised of $9.6 million related to new transmission projects, $1.7 million related to energy marketing and trading activities, $0.8 million related to workers' compensation, and $2.4 million related to other operating activities, for a total outstanding balance of $14.5 million.

OTHER INFORMATION

Sustainable Cost Reduction Activities

We have been reviewing our operations to identify sustainable cost savings. This review involves identifying process improvements, streamlining organizational structures, and developing other labor and non-labor efficiencies. To date in this ongoing effort, we have identified approximately $16.0 million of anticipated annualized savings and recorded $4.5 million of expense during 2012 related to achieving these cost savings.

Changes in Prices

KCC Proceedings

In October 2012, the KCC issued an order allowing us to adjust our prices to include previously deferred amounts associated with various energy efficiency programs. The new prices were effective in October 2012 and are expected to increase our annual retail revenues by approximately $1.1 million.

In September 2012, the KCC issued a final order approving an adjustment to our prices that we implemented in April 2012. The adjustment includes updated transmission costs as reflected in our transmission formula rate effective in January 2012 discussed below and is expected to increase our annual retail revenues by approximately $36.7 million. We filed an application with the KCC in February 2013 to adjust our prices to include updated transmission costs as reflected in our transmission formula rate effective in January 2013 discussed below. If approved, we estimate that the new prices will increase our annual retail revenues by approximately $9.1 million. We expect the KCC to issue an order on our request in March 2013.

In May 2012, the KCC issued an order allowing us to adjust our prices to include costs associated with investments in air quality equipment made in 2011. The new prices were effective in June 2012, and are expected to increase our annual retail revenues by approximately $19.5 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. The KCC also approved our request to file an abbreviated rate review within 12 months of this order to update our prices to include capital costs related to environmental projects at La Cygne. We plan to file an abbreviated rate review in April 2013 for recovery of approximately $350.0 million of our share of the La Cygne environmental upgrades.

FERC Proceedings

In October 2012, we posted our updated transmission formula rate that includes projected 2013 transmission capital expenditures and operating costs. The updated rate was effective in January 2013 and is expected to increase our annual transmission revenues by approximately $12.2 million.

Our transmission formula rate that includes projected 2012 transmission capital expenditures and operating costs was effective in January 2012 and was expected to increase our annual transmission revenues by approximately $38.2 million. The transmission formula rate provides the basis for our annual request with the KCC to adjust our retail prices to include updated transmission costs necessary to serve our retail customers.

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 early 2012 coupled with the longer than planned refueling and maintenance outage in the spring of 2011, we were able to defer the next planned refueling and maintenance outage from the fall of 2012 to the first quarter of 2013.

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. As certain of these regulations for the Dodd-Frank Act have not yet been finalized, we cannot predict what the impact might be. We will continue to evaluate the Dodd-Frank Act as implementing regulations are finalized.

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 $4.2 million as of December 31, 2012, 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 $3.5 million as of December 31, 2012, 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.

Within our energy trading portfolio, we may establish certain positions intended to economically hedge a portion of physical sale or purchase contracts and we may enter into certain positions attempting to take advantage of market trends and conditions. We use the term economic hedge to mean a strategy intended to manage risks of volatility in prices or rate movements on selected assets, liabilities or anticipated transactions by creating a relationship in which gains or losses on derivative instruments are expected to offset the losses or gains on the assets, liabilities or anticipated transactions exposed to such market risks. At the time we enter into these transactions, we are unable to determine the hedge value until the agreements are actually settled. Our future exposure to changes in prices will be dependent on the market prices and the extent and effectiveness of any economic hedging arrangements into which we enter. Additionally, net open positions exist, or are established, due to the origination of new transactions and our assessment of, and response to, changing market conditions. To the extent we have net open positions, we are exposed to the risk that changing market prices could have a material impact on our consolidated financial results.

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 2012 and 2011 were as follows:

	2012	2011
	(In Thousands)	
High	$ 309	$ 272
Low	10	31
Average	84	113

We have considered a variety of risks and costs associated with the future contractual commitments included in our trading portfolios. These risks include valuation and marking of illiquid pricing locations and products, the financial condition of our counterparties and interest rate movement. See the credit risk and interest rate risk discussions below for additional information. Also, there can be no assurance that the employment of VaR, credit practices or other risk management tools we employ will eliminate possible losses.

Credit Risk

We are exposed to counterparty default risk with our retail, wholesale and energy marketing activities, including participation in RTOs. Such credit risk is associated with the financial condition of counterparties, product location (basis) pricing differentials, physical liquidity constraints and other risks. Declines in the creditworthiness of our counterparties could have a material impact on our overall exposure to credit risk. We maintain credit policies with regard to our counterparties intended to reduce our overall credit risk. We also employ additional credit risk control mechanisms that we believe are appropriate, such as requiring counterparties to issue letters of credit or parental guarantees in our favor and entering into master netting agreements with counterparties that allow for offsetting exposures.

Certain of our derivative instruments contain collateral provisions subject to certain of our debt ratings. If such debt ratings were to decrease or fall below investment grade, the counterparties to the derivative instruments, pursuant to the provisions, could require collateralization on derivative instruments. The aggregate fair value of all derivative instruments with objective credit-risk-related contingent features that were in a liability position as of December 31, 2012 and 2011, was $0.8 million and $3.1 million, respectively, for which we had posted no collateral as of either date. If all credit-risk-related contingent features underlying these agreements had been triggered as of December 31, 2012 and 2011, we would have been required to provide to our counterparties $0.1 million and $0.5 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

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 $487.1 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2012. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $4.8 million. As of December 31, 2012, 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 would most likely 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, 2012, investments in the NDT were allocated 61% to equity securities, 29% to debt securities, 5% to combination debt/equity securities, 5% to real estate securities and less than 1% to cash equivalents. As of December 31, 2012 and 2011, the fair value of the NDT investments was $150.8 million and $130.3 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 $15.1 million decrease in the value of the NDT as of December 31, 2012.

We also maintain a trust to fund non-qualified retirement benefits. As of December 31, 2012, 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 $43.5 million as of December 31, 2012, and $40.2 million as of December 31, 2011. 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 $4.3 million decrease in the value of the trust as of December 31, 2012.

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

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, 2012. 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, 2012, 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, 2012, based on criteria established in *Internal Control - Integrated Framework* 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, 2012, based on the criteria established in *Internal Control - Integrated Framework* 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, 2012 and our report dated February 28, 2013 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 28, 2013

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, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 28, 2013

WESTAR ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands, Except Par Values)

	As of December 31, 2012	As of December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5,829	$ 3,539
Restricted cash	573	—
Accounts receivable, net of allowance for doubtful accounts of $4,916 and $7,384, respectively	224,439	226,428
Fuel inventory and supplies	249,016	229,118
Taxes receivable	—	5,334
Deferred tax assets	—	394
Prepaid expenses	15,847	13,078
Regulatory assets	114,895	123,818
Other	32,476	31,876
Total Current Assets	643,075	633,585
PROPERTY, PLANT AND EQUIPMENT, NET	7,013,765	6,411,922
PROPERTY, PLANT AND EQUIPMENT OF VARIABLE INTEREST ENTITIES, NET	321,975	333,494
OTHER ASSETS:		
Regulatory assets	887,777	922,272
Nuclear decommissioning trust	150,754	130,270
Other	247,885	251,308
Total Other Assets	1,286,416	1,303,850
TOTAL ASSETS	$ 9,265,231	$ 8,682,851
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt of variable interest entities	$ 25,942	$ 28,114
Short-term debt	339,200	286,300
Accounts payable	180,825	187,428
Accrued dividends	41,743	40,463
Accrued taxes	58,624	52,451
Accrued interest	77,891	77,437
Regulatory liabilities	37,557	40,857
Other	84,359	114,237
Total Current Liabilities	846,141	827,287
LONG-TERM LIABILITIES:		
Long-term debt, net	2,819,271	2,491,109
Long-term debt of variable interest entities, net	222,743	249,283
Deferred income taxes	1,197,837	1,110,463
Unamortized investment tax credits	191,512	164,175
Regulatory liabilities	285,618	230,530
Accrued employee benefits	564,870	592,617
Asset retirement obligations	152,648	142,508
Other	74,336	74,138
Total Long-Term Liabilities	5,508,835	5,054,823
COMMITMENTS AND CONTINGENCIES (See Notes 13 and 15)		
EQUITY:		
Westar Energy, Inc. Shareholders' Equity:		
Cumulative preferred stock, par value $100 per share; authorized 600,000 shares; issued and outstanding zero shares and 214,363 shares, respective to each date	—	21,436
Common stock, par value $5 per share; authorized 275,000,000 shares; issued and outstanding 126,503,748 shares and 125,698,396 shares, respective to each date	632,519	628,492
Paid-in capital	1,656,972	1,639,503
Retained earnings	606,649	501,216
Total Westar Energy, Inc. Shareholders' Equity	2,896,140	2,790,647
Noncontrolling Interests	14,115	10,094
Total Equity	2,910,255	2,800,741
TOTAL LIABILITIES AND EQUITY	$ 9,265,231	$ 8,682,851

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

WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2012	2011	2010
REVENUES	$ 2,261,470	$ 2,170,991	$ 2,056,171
OPERATING EXPENSES:			
Fuel and purchased power	589,990	630,793	583,361
Operating and maintenance	612,871	557,752	520,409
Depreciation and amortization	270,464	285,322	271,937
Selling, general and administrative	226,012	184,695	207,607
Total Operating Expenses	1,699,337	1,658,562	1,583,314
INCOME FROM OPERATIONS	562,133	512,429	472,857
OTHER INCOME (EXPENSE):			
Investment earnings	7,411	9,301	7,026
Other income	35,378	8,652	5,369
Other expense	(19,987)	(18,398)	(16,655)
Total Other Income (Expense)	22,802	(445)	(4,260)
Interest expense	176,337	172,460	174,941
INCOME BEFORE INCOME TAXES	408,598	339,524	293,656
Income tax expense	126,136	103,344	85,032
NET INCOME	282,462	236,180	208,624
Less: Net income attributable to noncontrolling interests	7,316	5,941	4,728
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY	275,146	230,239	203,896
Preferred dividends	1,616	970	970
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 273,530	$ 229,269	$ 202,926
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY (see Note 2):			
Basic earnings per common share	$ 2.15	$ 1.95	$ 1.81
Diluted earnings per common share	$ 2.15	$ 1.93	$ 1.80
AVERAGE EQUIVALENT COMMON SHARES OUTSTANDING	126,711,869	116,890,552	111,629,292
DIVIDENDS DECLARED PER COMMON SHARE	$ 1.32	$ 1.28	$ 1.24

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

WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	Year Ended December 31,		
	2012	2011	2010
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$ 282,462	$ 236,180	$ 208,624
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	270,464	285,322	271,937
Amortization of nuclear fuel	24,369	21,151	25,089
Amortization of deferred regulatory gain from sale leaseback	(5,495)	(5,495)	(5,495)
Amortization of corporate-owned life insurance	28,792	25,650	20,650
Non-cash compensation	7,255	8,422	11,373
Net changes in energy marketing assets and liabilities	(372)	926	(1,284)
Net deferred income taxes and credits	126,248	111,723	120,169
Stock-based compensation excess tax benefits	(1,698)	(1,180)	(641)
Allowance for equity funds used during construction	(11,706)	(5,550)	(3,104)
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	2,408	(1,638)	(11,434)
Fuel inventory and supplies	(19,227)	(21,485)	(12,266)
Prepaid expenses and other	(3,630)	(50,138)	8,475
Accounts payable	(19,161)	3,008	30,330
Accrued taxes	11,937	18,633	27,565
Other current liabilities	(105,169)	(107,012)	(80,660)
Changes in other assets	13,015	(10,167)	(42,544)
Changes in other liabilities	(1,386)	(16,369)	40,918
Cash Flows from Operating Activities	599,106	462,696	607,702
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(810,209)	(697,451)	(540,076)
Purchase of securities within trusts	(20,473)	(49,737)	(192,350)
Sale of securities within trusts	21,604	47,534	191,603
Proceeds from trust	2,022	—	—
Investment in corporate-owned life insurance	(18,404)	(19,214)	(19,162)
Proceeds from investment in corporate-owned life insurance	33,542	1,295	2,204
Proceeds from federal grant	4,775	8,561	3,180
Investment in affiliated company	(8,669)	(1,943)	(280)
Proceeds from sale of non-utility investments	—	9,246	—
Other investing activities	(1,525)	193	(1,164)
Cash Flows used in Investing Activities	(797,337)	(701,516)	(556,045)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	52,900	54,081	(16,060)
Proceeds from long-term debt	541,374	—	—
Retirements of long-term debt	(220,563)	(371)	(1,695)
Retirements of long-term debt of variable interest entities	(28,114)	(30,159)	(28,610)
Repayment of capital leases	(2,679)	(2,233)	(2,981)
Borrowings against cash surrender value of corporate-owned life insurance	67,791	67,562	74,134
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(34,838)	(3,421)	(3,430)
Stock-based compensation excess tax benefits	1,698	1,180	641
Preferred stock redemption	(22,567)	—	—
Issuance of common stock	6,996	294,942	54,651
Distributions to shareholders of noncontrolling interests	(3,295)	(1,917)	(2,093)
Cash dividends paid	(158,182)	(138,233)	(129,146)
Cash Flows from (used in) Financing Activities	200,521	241,431	(54,589)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,290	2,611	(2,932)
CASH AND CASH EQUIVALENTS:			
Beginning of period	3,539	928	3,860
End of period	$ 5,829	$ 3,539	$ 928

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

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WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Dollars in Thousands)

	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
Balance as of December 31, 2009	214,363	$ 21,436	109,072,000	$ 545,360	$ 1,339,790	$ 360,199	$ —	$ 2,266,785
Net income	—	—	—	—	—	203,896	4,728	208,624
Issuance of stock	—	—	3,056,068	15,280	50,759	—	—	66,039
Preferred dividends	—	—	—	—	—	(970)	—	(970)
Dividends on common stock ($1.24 per share)	—	—	—	—	—	(139,478)	—	(139,478)
Transfer to temporary equity	—	—	—	—	(22)	—	—	(22)
Amortization of restricted stock	—	—	—	—	10,710	—	—	10,710
Stock compensation and tax benefit	—	—	—	—	(2,657)	—	—	(2,657)
Consolidation of noncontrolling interests	—	—	—	—	—	—	3,435	3,435
Distributions to shareholders of noncontrolling interests	—	—	—	—	—	—	(2,093)	(2,093)
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	—	—	13,570,328	67,852	243,081	—	—	310,933
Preferred dividends	—	—	—	—	—	(970)	—	(970)
Dividends on common stock ($1.28 per share)	—	—	—	—	—	(151,700)	—	(151,700)
Transfer from temporary equity	—	—	—	—	3,465	—	—	3,465
Amortization of restricted stock	—	—	—	—	7,698	—	—	7,698
Stock compensation and tax benefit	—	—	—	—	(13,321)	—	—	(13,321)
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	—	—	805,352	4,027	19,143	—	—	23,170
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)
Amortization of restricted stock	—	—	—	—	6,430	—	—	6,430
Stock compensation and tax benefit	—	—	—	—	(8,104)	—	—	(8,104)
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

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 690,000 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.

Restricted Cash

Pursuant to Westar Energy's Articles of Incorporation, Westar Energy deposited cash in a separate bank account to effect the redemption of all of Westar Energy's preferred stock in 2012. See Note 16, "Common and Preferred Stock," for additional information regarding the preferred stock redemption.

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,	
	2012	2011
	(In Thousands)	
Fuel inventory	$ 94,664	$ 86,408
Supplies	154,352	142,710
Total	$ 249,016	$ 229,118

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,		
	2012	2011	2010
	(Dollars In Thousands)		
Borrowed funds	$ 10,399	$ 5,589	$ 4,295
Equity funds	11,706	5,550	3,104
Total	$ 22,105	$ 11,139	$ 7,399
Average AFUDC Rates	5.0%	3.6%	2.6%

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 2.6% in 2012, 3.0% in 2011 and 2.9% in 2010.

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

	Years		
Fossil fuel generating facilities	6	to	78
Nuclear fuel generating facility	33	to	71
Wind generating facilities	19	to	20
Transmission facilities	15	to	75
Distribution facilities	15	to	70
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 $69.2 million as of December 31, 2012, and $44.8 million as of December 31, 2011. The cost of nuclear fuel charged to fuel and purchased power expense was $28.3 million in 2012, $24.6 million in 2011 and $29.2 million in 2010.

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,	
	2012	2011
	(In Thousands)	
Cash surrender value of policies	$ 1,370,788	$ 1,345,443
Borrowings against policies	(1,241,343)	(1,208,389)
Corporate-owned life insurance, net	$ 129,445	$ 137,054

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

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 $62.5 million as of December 31, 2012, and $54.0 million as of December 31, 2011.

Energy Marketing Contracts

We account for energy marketing derivative contracts under the fair value method of accounting. Under this method, we recognize changes in the portfolio value as gains or losses in the period of change. With the exception of certain fuel supply and electricity contracts, which we record as regulatory assets or regulatory liabilities, we include the net change in fair value in revenues on our consolidated statements of income. We record the unrealized gains and losses in other current assets and other current liabilities or in other assets and other long-term liabilities on our consolidated balance sheets as appropriate. We use quoted market prices to value our energy marketing derivative contracts when such data are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. The prices we use to value these transactions reflect our best estimate of the fair value of these contracts. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

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 carry forward into future periods capital losses, operating losses and tax credits. 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, RSUs with forfeitable rights to dividend equivalents and stock options. 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,		
	2012	2011	2010
	(Dollars In Thousands, Except Per Share Amounts)		
Net income	$ 282,462	$ 236,180	$ 208,624
Less: Net income attributable to noncontrolling interests	7,316	5,941	4,728
Net income attributable to Westar Energy, Inc.	275,146	230,239	203,896
Less: Preferred dividends	1,616	970	970
Net income allocated to RSUs	778	772	1,259
Net income allocated to common stock	$ 272,752	$ 228,497	$ 201,667
Weighted average equivalent common shares outstanding – basic	126,711,869	116,890,552	111,629,292
Effect of dilutive securities:			
RSUs	97,757	188,025	140,077
Forward sale agreements	89,160	1,211,645	245,496
Employee stock options	—	—	59
Weighted average equivalent common shares outstanding – diluted (a)	126,898,786	118,290,222	112,014,924
Earnings per common share, basic	$ 2.15	$ 1.95	$ 1.81
Earnings per common share, diluted	$ 2.15	$ 1.93	$ 1.80

(a) For the years ended December 31, 2012, 2011 and 2010, we had no antidilutive shares.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$ 143,564	$ 145,570	$ 145,463
Interest on financing activities of VIEs	16,214	18,167	20,191
Income taxes, net of refunds	(4,378)	(17,519)	(34,980)
NON-CASH INVESTING TRANSACTIONS:			
Property, plant and equipment additions	89,354	105,435	64,423
Property, plant and equipment additions of VIEs	—	—	356,964
Jeffrey Energy Center (JEC) 8% leasehold interest	—	—	(108,706)
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and compensation plans	12,803	15,103	18,777
Debt of VIEs	—	—	337,951
Capital lease for JEC 8% leasehold interest	—	—	(106,423)
Assets acquired through capital leases	10,683	43,011	910

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,	
	2012	2011
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$ 542,174	$ 560,915
Amounts due from customers for future income taxes, net	169,091	168,804
Depreciation	73,672	76,298
Debt reacquisition costs	67,721	66,856
Treasury yield hedges	28,573	33,753
Asset retirement obligations	22,633	22,196
Ad valorem tax	21,812	6,622
Energy efficiency program costs	18,835	16,521
Disallowed plant costs	16,106	16,236
Wolf Creek outage	14,143	25,033
Storm costs	11,076	25,747
Retail energy cost adjustment	4,262	19,587
Other regulatory assets	12,574	7,522
Total regulatory assets	$ 1,002,672	$ 1,046,090
Regulatory Liabilities:		
Removal costs	$ 128,971	$ 82,338
Deferred regulatory gain from sale leaseback	92,046	97,541
Nuclear decommissioning	25,937	12,544
La Cygne dismantling costs	18,093	15,680
Retail energy cost adjustment	16,595	25,225
Kansas tax credits	10,781	8,497
Other post-retirement benefits costs	10,722	11,125
Gain on sale of oil	6,219	5,822
Fuel supply and electricity contracts	4,387	6,177
Other regulatory liabilities	9,424	6,438
Total regulatory liabilities	$ 323,175	$ 271,387

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 $485.5 million for pension and post-retirement benefit obligations and $56.7 million for actual pension expense in excess of the amount of such expense recognized in setting our prices. During 2013, we will amortize to expense approximately $44.2 million of the benefit obligations and approximately $9.8 million of the excess pension expense. As authorized in the April 2012 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.

- **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 and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management—Derivative Instruments—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.

- **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.

- **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.

- **Disallowed plant costs:** In 1985, the Kansas Corporation Commission (KCC) disallowed certain costs associated with the original construction of Wolf Creek. In 1987, the KCC authorized KGE to recover these costs in prices over the useful life of Wolf Creek. 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.

- **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 amortize these costs over periods ranging from three to five years and earn a return on a majority of 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.

- **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 fair value of our ARO. See Note 4, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management," 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.

- **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:** 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.

- **Other post-retirement benefits costs:** Represents the amount 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.

- **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 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. The KCC also approved our request to file an abbreviated rate review within 12 months of this order to update our prices to include capital costs related to environmental projects at La Cygne.

In January 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with investments in natural gas and wind generation facilities. The new prices were effective in February 2010 and were expected to increase our annual retail revenues by approximately $17.1 million.

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, the KCC approved our request to file an abbreviated rate review to update our prices to include 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:

- $19.5 million effective in June 2012;
- $10.4 million effective in June 2011; and
- $13.8 million effective in June 2010.

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:

- $36.7 million effective in April 2012;
- $17.4 million effective in April 2011; and
- $6.4 million effective in March 2010.

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 increase our annual retail revenues by approximately:

- $1.1 million effective in October 2012;
- $4.9 million effective in November 2011; and
- $5.8 million effective in November 2010.

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:

- $38.2 million effective in January 2012;
- $15.9 million effective in January 2011; and
- $16.8 million effective in January 2010.

4. FINANCIAL AND DERIVATIVE INSTRUMENTS, TRADING SECURITIES, ENERGY MARKETING AND RISK MANAGEMENT

Values of Financial and Derivative Instruments

GAAP establishes a hierarchal 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 and exchange-traded futures contracts.

- 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, such as commodity options priced using observable forward prices and volatilities.

- 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, such as the complex and subjective models and forecasts used to determine the fair value of options, private equity and real estate securities and long-term electricity supply contracts.

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 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 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.

Energy marketing contracts can be exchange-traded or traded over-the-counter (OTC). Fair value measurements of exchange-traded contracts typically utilize quoted prices in active markets. OTC contracts are valued using market transactions and other market evidence whenever possible, including market-based inputs to models, model calibration to market clearing transactions or alternative pricing sources with reasonable levels of price transparency. Valuation models require a variety of inputs, including contractual terms, market prices, yield curves, credit curves, nonperformance risk, measures of volatility and correlations of such inputs. Certain OTC contracts trade in less liquid markets with limited pricing information and the determination of fair value for these derivatives is inherently more subjective. In these situations, estimates by management are a significant input. Our risk management department, which reports to the Chief Financial Officer, has established valuation processes and procedures to ensure that the valuation methodologies for energy marketing transactions are fair and consistent. Methodologies are periodically reviewed and tested to ensure they are representative of the current market dynamics. See
"-Recurring Fair Value Measurements" and "-Derivative Instruments" below for additional information.

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, 2012		As of December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In Thousands)			
Fixed-rate debt	$ 2,702,500	$ 3,178,752	$ 2,373,063	$ 2,623,993
Fixed-rate debt of VIEs	247,624	275,341	275,738	306,027

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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, 2012	Level 1	Level 2	Level 3	Total
	(In Thousands)			
Assets:				
Energy Marketing Contracts	$ —	$ 381	$ 8,429	$ 8,810
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	$ 181,651	$ 21,193	$ 203,048
Liabilities:				
Energy Marketing Contracts	$ —	$ 105	$ 1,367	$ 1,472
As of December 31, 2011				
Assets:				
Energy Marketing Contracts	$ —	$ 2,401	$ 13,330	$ 15,731
Nuclear Decommissioning Trust:				
Domestic equity	—	53,186	3,931	57,117
International equity	—	22,307	—	22,307
Core bonds	—	20,171	—	20,171
High-yield bonds	—	10,969	—	10,969
Emerging market bonds	—	5,309	—	5,309
Combination debt/equity fund	—	7,251	—	7,251
Real estate securities	—	—	7,095	7,095
Cash equivalents	51	—	—	51
Total Nuclear Decommissioning Trust	51	119,193	11,026	130,270
Trading Securities:				
Domestic equity	—	21,175	—	21,175
International equity	—	4,896	—	4,896
Core bonds	—	13,961	—	13,961
Cash equivalents	169	—	—	169
Total Trading Securities	169	40,032	—	40,201
Total Assets Measured at Fair Value	$ 220	$ 161,626	$ 24,356	$ 186,202
Liabilities:				
Energy Marketing Contracts	$ —	$ 2,475	$ 3,878	$ 6,353
Treasury Yield Hedges	—	34,025	—	34,025
Total Liabilities Measured at Fair Value	$ —	$ 36,500	$ 3,878	$ 40,378

We do not offset the fair value of energy marketing contracts executed with the same counterparty. As of December 31, 2012, we had no right to reclaim cash collateral and had recorded $1.8 million for our obligation to return cash collateral. As of December 31, 2011, we had no right to reclaim cash collateral and had recorded $2.9 million for our obligation to return cash collateral.

The following table provides reconciliations of assets and liabilities measured at fair value using significant level 3 inputs for the years ended December 31, 2012 and 2011.

	Energy Marketing Contracts, net		Nuclear Decommissioning Trust			Net Balance
			Domestic Equity	High-yield Bonds	Real Estate Securities	
	(In Thousands)					
Balance as of December 31, 2011	$ 9,452		$ 3,931	$ —	$ 7,095	$ 20,478
Total realized and unrealized gains (losses) included in:						
Earnings (a)	2,176		—	—	—	2,176
Regulatory assets	(696)	(b)	—	—	—	(696)
Regulatory liabilities	2,114	(b)	90	—	770	2,974
Purchases	(5,034)		891	—	320	(3,823)
Sales	(620)		(13)	—	(320)	(953)
Settlements	(330)		—	—	—	(330)
Balance as of December 31, 2012	$ 7,062		$ 4,899	$ —	$ 7,865	$ 19,826
Balance as of December 31, 2010	$ 11,815		$ 2,867	$ 305	$ 3,049	$ 18,036
Total realized and unrealized gains (losses) included in:						
Earnings (a)	603		—	—	—	603
Regulatory assets	(1,450)	(b)	—	—	—	(1,450)
Regulatory liabilities	2,993	(b)	479	—	670	4,142
Purchases	(6,145)		608	—	3,455	(2,082)
Sales	1,022		(23)	(305)	(79)	615
Settlements	614		—	—	—	614
Balance as of December 31, 2011	$ 9,452		$ 3,931	$ —	$ 7,095	$ 20,478

(a) Unrealized gains and losses included in earnings are reported in revenues.
(b) Includes changes in the fair value of certain fuel supply and electricity contracts.

Portions of the gains and losses contributing to changes in net assets in the above table are unrealized. The following table summarizes the unrealized gains and losses we recorded on our consolidated financial statements during the years ended December 31, 2012 and 2011, attributed to level 3 assets and liabilities.

	Year Ended December 31, 2012				
			Nuclear Decommissioning Trust		
	Energy Marketing Contracts, net		Domestic Equity	Real Estate Securities	Net Balance
	(In Thousands)				
Total unrealized gains (losses) included in:					
Earnings (a)	$ (748)		$ —	$ —	$ (748)
Regulatory assets	(74)	(b)	—	—	(74)
Regulatory liabilities	332	(b)	77	451	860
Total	$ (490)		$ 77	$ 451	$ 38
	Year Ended December 31, 2011				
Total unrealized gains (losses) included in:					
Earnings (a)	$ (898)		$ —	$ —	$ (898)
Regulatory assets	(747)	(b)	—	—	(747)
Regulatory liabilities	1,736	(b)	456	591	2,783
Total	$ 91		$ 456	$ 591	$ 1,138

(a) Unrealized gains and losses included in earnings are reported in revenues.

(b) Includes changes in the fair value of certain fuel supply and electricity contracts.

Our level 3 investments require unobservable quantitative inputs to measure fair value. The following table summarizes the quantitative inputs and assumptions for our level 3 investments not measured at net asset value.

	Fair Value as of December 31, 2012				
	Assets	Liabilities	Valuation Methodology	Unobservable Inputs	Range of Inputs
	(In Thousands)				
Electricity - Forwards	$ 862	$ 358	Discounted cash flow	Basis (MWh)	$0 to $15
Gas - Forwards	—	74	Discounted cash flow	Basis (mmBtu)	$0 to $0.25
Options	7,567	935	Discounted cash flow	Basis - Electricity (MWh)	$0 to $15
				Basis - Gas (mmBtu)	$0 to $0.25
			Option models	Volatility - Electricity	10% to 75%
				Volatility - Gas	20% to 35%
				Correlation	60% to 90%
Total	$ 8,429	$ 1,367			

Our fair value measurement of energy marketing contracts is sensitive to level 3 fair value inputs. Increases or decreases to one unobservable input may magnify or mitigate the impact of other inputs. Holding all other inputs constant, an increase (decrease) in a significant unobservable input would typically impact our fair value measurement as follows.

Significant Unobservable Input	Position	Impact on Fair Value Measurement
Basis	Purchase	Increase (decrease)
	Sell	Decrease (increase)
Volatility	Purchase Option	Increase (decrease)
	Sell Option	Decrease (increase)
Correlation	Purchase Option	Decrease (increase)
	Sell Option	Increase (decrease)

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, 2012		As of December 31, 2011		As of December 31, 2012	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
	(In Thousands)					
Nuclear Decommissioning Trust:						
Domestic equity	$ 4,899	$ 1,024	$ 3,931	$ 1,914	(a)	(a)
Real estate securities	7,865	—	7,095	—	Quarterly	80 days
Total Nuclear Decommissioning Trust	$ 12,764	$ 1,024	$ 11,026	$ 1,914		
Trading Securities:						
Domestic equity	$ 22,470	$ —	$ 21,175	$ —	Upon Notice	1 day
International equity	5,744	—	4,896	—	Upon Notice	1 day
Core bonds	15,104	—	13,961	—	Upon Notice	1 day
Total Trading Securities	43,318	—	40,032	—		
Total	$ 56,082	$ 1,024	$ 51,058	$ 1,914		

(a) This investment is in two 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 making distributions and we expect the other to begin in 2013.

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 2012, we recorded $3.1 million of additional AROs. In 2011, we recorded $9.9 million of additional AROs to reflect revisions to the estimated cost to decommission Wolf Creek. 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 as of December 31, 2012, 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

We entered into treasury yield hedge transactions to hedge our interest rate risk associated with a $125.0 million portion of a forcaseted 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. As of December 31, 2011, we had recorded $34.0 million in other current liabilities on our consolidated balance sheet to reflect the fair value of the treasury yield hedge transactions and $33.8 million in long-term regulatory assets to reflect the effective portion. We recorded $0.2 million of hedge ineffectiveness losses in interest expense on our consolidated statements of income for the year ended December 31, 2011. 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, 2012, we had recorded $28.6 million as a regulatory asset.

Commodity Contracts

We engage in both financial and physical trading with the goal of managing our commodity price risk, enhancing system reliability and increasing profits. We trade electricity and other energy-related products using a variety of financial instruments, which may include futures contracts, options, swaps and physical commodity contracts.

We classify these commodity derivative instruments as other current and other long-term assets and liabilities on our consolidated balance sheets. We report energy marketing contracts representing unrealized gain positions as assets; energy marketing contracts representing unrealized loss positions are reported as liabilities. With the exception of certain fuel supply and electricity contracts, which we record as regulatory assets or regulatory liabilities, we include the change in the fair value of energy marketing contracts in revenues on our consolidated statements of income. The following table presents the fair value of commodity derivative instruments reflected on our consolidated balance sheets.

Commodity Derivatives Not Designated as Hedging Instruments as of December 31, 2012

Asset Derivatives		**Liability Derivatives**	
Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
	(In Thousands)		(In Thousands)
Current assets:		Current liabilities:	
Other	$ 4,776	Other	$ 1,472
Other assets:			
Other	4,034		
Total	$ 8,810		

Commodity Derivatives Not Designated as Hedging Instruments as of December 31, 2011

Asset Derivatives		**Liability Derivatives**	
Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
	(In Thousands)		(In Thousands)
Current assets:		Current liabilities:	
Other	$ 8,180	Other	$ 6,353
Other assets:			
Other	7,551		
Total	$ 15,731		

The following table presents how changes in the fair value of commodity derivative instruments increased (decreased) line items on our consolidated financial statements for the years ended December 31, 2012 and 2011.

	Year Ended December 31, 2012		Year Ended December 31, 2011	
Location	Net Gain Recognized	Net Loss Recognized	Net Gain Recognized	Net Loss Recognized
	(In Thousands)			
Revenues	$ 6,200	$ —	$ 1,569	$ —
Regulatory assets	(374)	—	—	374
Regulatory liabilities	—	(1,790)	—	(1,623)

As of December 31, 2012 and 2011, we had under contract the following commodity derivatives.

		Net Quantity as of	
	Unit of Measure	December 31, 2012	December 31, 2011
Electricity	MWh	1,955,497	1,834,253
Natural Gas	MMBtu	1,674,000	1,467,500

Net open positions exist, or are established, due to the origination of new transactions and our assessment of, and response to, changing market conditions. To the extent we have net open positions, we are exposed to the risk that changing market prices could have a material impact on our consolidated financial results.

Energy Marketing Activities

Within our energy trading portfolio, we may establish certain positions intended to economically hedge a portion of physical sale or purchase contracts and we may enter into certain positions attempting to take advantage of market trends and conditions. We use the term economic hedge to mean a strategy intended to manage risks of volatility in prices or rate movements on selected assets, liabilities or anticipated transactions by creating a relationship in which gains or losses on derivative instruments are expected to offset the losses or gains on the assets, liabilities or anticipated transactions exposed to such market risks.

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.

Credit Risk

In addition to commodity price risk, we are exposed to credit risks associated with the financial condition of counterparties, product location (basis) pricing differentials, physical liquidity constraints and other risks. Declines in the creditworthiness of our counterparties could have a material impact on our overall exposure to credit risk. We maintain credit policies with regard to our counterparties intended to reduce our overall credit risk exposure to a level we deem acceptable and include the right to offset derivative assets and liabilities by counterparty.

We have derivative instruments with commodity exchanges and other counterparties that do not contain objective credit-risk-related contingent features. However, certain of our derivative instruments contain collateral provisions subject to certain of our debt ratings. If such debt ratings were to decrease or fall below investment grade, the counterparties to the derivative instruments, pursuant to the provisions, could require collateralization on derivative instruments. The aggregate fair value of all derivative instruments with objective credit-risk-related contingent features that were in a liability position as of December 31, 2012 and 2011, was $0.8 million and $3.1 million, respectively, for which we had posted no collateral as of either date, including independent amounts. If all credit-risk-related contingent features underlying these agreements had been triggered as of December 31, 2012 and 2011, we would have been required to provide to our counterparties $0.1 million and $0.5 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

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 $30.0 million and $29.4 million as of December 31, 2012 and 2011, respectively. For additional information on our benefit obligations, see Note 11, "Employee Benefit Plans."

As of December 31, 2012 and 2011, we measured the fair value of trust assets at $43.5 million and $40.2 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, 2012, 2011 and 2010, we recorded unrealized gains of $4.1 million, $0.3 million and $4.3 million, respectively.

Available-for-Sale Securities

We hold investments in equity, debt and real estate securities 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, 2012 and 2011. As of December 31, 2012, the fair value of available-for-sale debt securities in the core, high-yield and emerging market bond funds was $43.6 million. As of December 31, 2012, the NDT did not have investments in debt securities outside of investment funds.

Using the specific identification method to determine cost, we realized gains on our available-for-sale securities of $0.6 million in 2012, $1.3 million in 2011 and $13.2 million in 2010. 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, 2012 and 2011.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Allocation
	(Dollars In Thousands)				
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%
As of December 31, 2011					
Domestic equity	$ 55,357	$ 1,760	$ —	$ 57,117	44%
International equity	24,501	—	(2,194)	22,307	17%
Core bonds	19,771	400	—	20,171	16%
High-yield bonds	11,046	—	(77)	10,969	8%
Emerging market bonds	5,301	8	—	5,309	4%
Combination debt/equity fund	7,524	—	(273)	7,251	6%
Real estate securities	9,662	—	(2,567)	7,095	5%
Cash equivalents	51	—	—	51	<1%
Total	$ 133,213	$ 2,168	$ (5,111)	$ 130,270	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, 2012 and 2011.

	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, 2012						
Real estate securities	$ —	$ —	$ 7,865	$ (2,116)	$ 7,865	$ (2,116)
As of December 31, 2011						
International equity	$ 22,307	$ (2,194)	$ —	$ —	$ 22,307	$ (2,194)
High-yield bonds	10,969	(77)	—	—	10,969	(77)
Combination debt/equity fund	7,251	(273)	—	—	7,251	(273)
Real estate securities	—	—	7,095	(2,567)	7,095	(2,567)
Total	$ 40,527	$ (2,544)	$ 7,095	$ (2,567)	$ 47,622	$ (5,111)

6. PROPERTY, PLANT AND EQUIPMENT

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

	As of December 31, 2012	As of December 31, 2011
	(In Thousands)	
Electric plant in service	$ 9,389,192	$ 8,703,278
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,791,545)	(3,703,372)
	6,399,965	5,802,224
Construction work in progress	532,332	534,003
Nuclear fuel, net	81,468	75,695
Net property, plant and equipment	$ 7,013,765	$ 6,411,922

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

	As of December 31, 2012	As of December 31, 2011
	(In Thousands)	
Electric plant of VIEs	$ 543,548	$ 543,548
Accumulated depreciation of VIEs	(221,573)	(210,054)
Net property, plant and equipment of VIEs	$ 321,975	$ 333,494

We revised our depreciation rates to reflect changes in the estimated useful lives of some of our assets. We recorded depreciation expense on property, plant and equipment of $247.8 million in 2012, $262.6 million in 2011 and $249.2 million in 2010. Approximately $9.8 million, $9.8 million and $9.7 million of depreciation expense in 2012, 2011 and 2010, 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, 2012, 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	$ 331,964	$ 156,722	$ 185,875	368	50
JEC unit 1 (a)	July 1978	528,478	196,511	80,217	661	92
JEC unit 2 (a)	May 1980	498,929	182,444	121	658	92
JEC unit 3 (a)	May 1983	703,393	282,481	1,000	664	92
Wolf Creek (b)	Sept. 1985	1,524,831	756,218	99,357	547	47
State Line (c)	June 2001	114,093	49,099	34	201	40
Total		$ 3,701,688	$ 1,623,475	$ 366,604	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 343 MW of net capacity. The VIE's investment in the 50% interest was $392.1 million and accumulated depreciation was $180.2 million as of December 31, 2012. 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 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 described below. 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 December 31, 2012, Westar Energy had issued $339.2 million of commercial paper. Westar Energy had no commercial paper outstanding as of December 31, 2011.

In September 2011, Westar Energy refinanced its existing $730.0 million revolving credit facility with a new facility in the same amount. The commitments under the new facility terminate in September 2016. As long as there is no default under the facility, Westar Energy may extend the facility up to an additional two years 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, 2012, no amounts had been borrowed and $13.8 million of letters of credit had been issued under this revolving credit facility. As of December 31, 2011, $286.3 million had been borrowed and an additional $12.2 million of letters of credit had been issued under this revolving credit facility.

In February 2011, Westar Energy entered into a revolving credit facility with a syndicate of banks for $270.0 million. In February 2013, Westar Energy extended this facility by one year. This facility now terminates in February 2016. As long as there is no default under the facility, Westar Energy may extend the facility one additional year and may increase the aggregate amount of borrowings under the facility to $400.0 million, both subject to lender participation. All borrowings under the facility are secured by KGE first mortgage bonds. As of December 31, 2012 and 2011, Westar Energy had no borrowed amounts or letters of credit outstanding under this revolving credit facility.

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 was 0.46% and 1.49% as of December 31, 2012 and 2011, respectively. Additional information regarding our short-term debt is as follows.

	As of December 31,	
	2012	2011
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$ 298,907	$ 362,946
Weighted daily average interest rates during the year, excluding fees	0.55%	0.82%

Our interest expense on short-term debt was $3.2 million in 2012, $3.9 million in 2011 and $1.9 million in 2010.

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9. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

	As of December 31,			
	2012		2011	
	(In Thousands)			
Westar Energy				
First mortgage bond series:				
6.00% due 2014	$	250,000	$	250,000
5.15% due 2017		125,000		125,000
5.95% due 2035		125,000		125,000
5.10% due 2020		250,000		250,000
5.875% due 2036		150,000		150,000
6.10% due 2047		—		150,000
8.625% due 2018		300,000		300,000
4.125% due 2042		550,000		—
		1,750,000		1,350,000
Pollution control bond series:				
Variable due 2032, 0.32% as of December 31, 2012; 0.22% as of December 31, 2011		45,000		45,000
Variable due 2032, 0.26% as of December 31, 2012; 0.24% as of December 31, 2011		30,500		30,500
5.00% due 2033		—		57,245
		75,500		132,745
KGE				
First mortgage bond series:				
6.53% due 2037		175,000		175,000
6.15% due 2023		50,000		50,000
6.64% due 2038		100,000		100,000
6.70% due 2019		300,000		300,000
		625,000		625,000
Pollution control bond series:				
5.10% due 2023		—		13,318
Variable due 2027, 0.26% as of December 31, 2012; 0.28% as of December 31, 2011		21,940		21,940
5.30% due 2031		108,600		108,600
5.30% due 2031		18,900		18,900
Variable due 2032, 0.26% as of December 31, 2012; 0.28% as of December 31, 2011		14,500		14,500
Variable due 2032, 0.26% as of December 31, 2012; 0.28% as of December 31, 2011		10,000		10,000
4.85% due 2031		50,000		50,000
5.60% due 2031		50,000		50,000
6.00% due 2031		50,000		50,000
5.00% due 2031		50,000		50,000
		373,940		387,258
Total long-term debt		2,824,440		2,495,003
Unamortized debt discount (a)		(5,169)		(3,894)
Long-term debt due within one year		—		—
Long-term debt, net	$	2,819,271	$	2,491,109
Variable Interest Entities				
7.77% due 2012 (b)	$	—	$	2,583
6.99% due 2014 (b)		866		2,094
5.92 % due 2019 (b)		17,630		22,748
5.647% due 2021 (b)		229,128		248,313
Total long-term debt of variable interest entities		247,624		275,738
Unamortized debt premium (a)		1,061		1,659
Long-term debt of variable interest entities due within one year		(25,942)		(28,114)
Long-term debt of variable interest entities, net	$	222,743	$	249,283

(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, 2012, approximately $830.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage, except in connection with certain refundings. As of December 31, 2012, approximately $870.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

As of December 31, 2012, 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 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. Proceeds from these issuances of $541.4 million 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.

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. The bonds were redeemed using short-term debt.

Debt Covenants

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, 2012.

Maturities

The principal amounts of our long-term debt maturities as of December 31, 2012, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2013	$ —	$ 25,942
2014	250,000	27,479
2015	—	27,933
2016	—	28,309
2017	125,000	26,842
Thereafter	2,449,440	111,119
Total maturities	$ 2,824,440	$ 247,624

Interest expense on long-term debt was $145.6 million in 2012, $142.6 million in 2011 and $144.1 million in 2010. Interest expense on long-term debt of VIEs was $15.1 million in 2012, $16.8 million in 2011 and $18.7 million in 2010.

10. TAXES

Income tax expense is comprised of the following components.

	Year Ended December 31,		
	2012	2011	2010
	(In Thousands)		
Income Tax Expense (Benefit):			
Current income taxes:			
Federal	$ (691)	$ (8,575)	$ (32,107)
State	579	196	(3,030)
Deferred income taxes:			
Federal	102,960	93,089	102,568
State	26,300	21,337	20,305
Investment tax credit amortization	(3,012)	(2,703)	(2,704)
Income tax expense	$ 126,136	$ 103,344	$ 85,032

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

	As of December 31,	
	2012	2011
	(In Thousands)	
Other current liabilities (assets)	$ 8,654	$ (394)
Non-current deferred tax liabilities	1,197,837	1,110,463
Deferred tax liabilities	$ 1,206,491	$ 1,110,069

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,	
	2012	2011
	(In Thousands)	
Deferred tax assets:		
Tax credit carryforward (a)	$ 199,160	$ 159,163
Deferred employee benefit costs	191,997	202,687
Net operating loss carryforward (b)	111,869	84,365
Deferred state income taxes	55,577	42,209
Deferred regulatory gain on sale-leaseback	40,543	42,962
Alternative minimum tax carryforward (c)	36,471	36,471
Deferred compensation	28,319	28,286
Accrued liabilities	15,969	16,912
Disallowed costs	12,083	12,717
Capital loss carryforward (d)	11,509	12,554
Other	20,897	13,031
Total gross deferred tax assets	724,394	651,357
Less: Valuation allowance (e)	13,812	13,712
Deferred tax assets	$ 710,582	$ 637,645
Deferred tax liabilities:		
Accelerated depreciation	$ 1,255,892	$ 1,088,727
Deferred employee benefit costs	191,997	202,687
Acquisition premium	179,920	187,934
Amounts due from customers for future income taxes, net	169,091	168,804
Deferred state income taxes	50,134	39,512
Pension expense tracker	22,437	14,600
Debt reacquisition costs	22,313	21,683
Storm costs	4,373	10,176
Other	20,916	13,591
Total deferred tax liabilities	$ 1,917,073	$ 1,747,714
Net deferred tax liabilities	$ 1,206,491	$ 1,110,069

(a) Based on filed tax returns and amounts expected to be reported in current year tax returns (December 31, 2012), we had available federal general business tax credits of $39.3 million and state investment tax credits of $159.8 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 2032. The state investment tax credits expire beginning in 2013 and ending in 2028. As we do not expect to realize sufficient state taxable income in 2013, a valuation allowance of $1.3 million has been established for the state investment tax credits that expire in 2013 (see item (e) below).

(b) As of December 31, 2012, we had a federal net operating loss carryforward of $276.9 million, which is available to offset federal taxable income. The net operating losses will expire beginning in 2030 and ending in 2032.

(c) As of December 31, 2012, we had available an alternative minimum tax credit carryforward of $36.5 million, which has an unlimited carryforward period.

(d) As of December 31, 2012, we had an unused capital loss carryforward of $29.1 million that is available to offset future capital gains. The capital losses will expire beginning in 2013 and ending in 2016.

(e) As we do not expect to realize any significant capital gains in the future, we have established a valuation allowance of $11.5 million. In addition, we have established a valuation allowance of $2.3 million for certain deferred tax assets related to the write-down of other investments and state investment tax credits. The total valuation allowance related to the deferred tax assets was $13.8 million as of December 31, 2012, and $13.7 million as of December 31, 2011.

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,		
	2012	2011	2010
Statutory federal income tax rate	35.0 %	35.0 %	35.0 %
Effect of:			
Corporate-owned life insurance policies	(4.9)	(4.5)	(6.1)
State income taxes	4.3	4.1	3.8
Production tax credits	(2.4)	(2.9)	(3.4)
Flow through depreciation for plant-related differences	1.4	1.8	2.6
AFUDC equity	(1.0)	(0.6)	(0.4)
Amortization of federal investment tax credits	(0.7)	(0.8)	(0.9)
Capital loss utilization	(0.3)	(0.5)	(0.7)
Liability for unrecognized income tax benefits	0.2	—	(0.2)
Other	(0.7)	(1.2)	(0.7)
Effective income tax rate	30.9 %	30.4 %	29.0 %

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.

In the first and second quarters of 2011, the IRS completed its separate examinations of our federal income tax returns filed for tax years 2008 and 2009, respectively, without significant changes.

In May 2012, the IRS commenced an examination of our 2010 federal income tax return and the amended federal income tax returns we filed for years 2007, 2008 and 2009. The examination was completed in January 2013 and resulted in a refund which is subject to formal review and approval by the IRS and the Joint Committee on Taxation of the U.S. Congress. The examination results will not have a significant impact on our consolidated statements of income or cash flows. We believe that it is reasonably possible that the administrative reviews will be completed in 2013.

The liability for unrecognized income tax benefits decreased from $2.5 million at December 31, 2011, to $1.2 million at December 31, 2012. The net decrease in the liability for unrecognized income tax benefits resulted from the reversal of a liability for unrecognized income tax benefits related to the capitalization of plant expenditures. The reversal was based on additional IRS guidance regarding deduction and capitalization of expenditures related to tangible property. 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:

	2012	2011	2010
		(In Thousands)	
Liability for unrecognized income tax benefits as of January 1	$ 2,483	$ 1,888	$ 8,357
Additions based on tax positions related to the current year	373	967	608
Additions for tax positions of prior years	—	939	2,323
Reductions for tax positions of prior years	(1,637)	(563)	(1,241)
Settlements	—	(748)	(8,159)
Liability for unrecognized income tax benefits as of December 31	$ 1,219	$ 2,483	$ 1,888

The liability for unrecognized income tax benefits, as disclosed above, is net of reductions to deferred tax assets for tax loss and credit carryforwards of $0.3 million, $0.2 million and $1.0 million as of December 31, 2012, 2011 and 2010, respectively. The amounts of unrecognized income tax benefits that, if recognized, would favorably impact our effective income tax rate, were $2.0 million, $1.2 million and $1.3 million (net of tax) as of December 31, 2012, 2011 and 2010, respectively.

Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. During 2011 and 2010, we reversed interest expense previously recorded for income tax uncertainties of $0.2 million and $1.0 million, respectively. As of December 31, 2012 and 2011, 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, 2012, or December 31, 2011.

As of December 31, 2012 and 2011, we had recorded $1.5 million for probable assessments of taxes other than income taxes.

11. EMPLOYEE BENEFIT PLANS

Pension and Post-Retirement Benefit Plans

We maintain a qualified non-contributory defined benefit pension plan covering substantially all of our employees. For the majority of our employees, pension benefits are based on years of service and an employee's compensation during the 60 highest paid consecutive months out of 120 before retirement. Non-union employees hired after December 31, 2001, and union employees hired after December 31, 2011, are covered by the same defined benefit pension plan; however, their benefits are derived from a cash balance account formula. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain current and retired executive officers. With the exception of one current executive officer, 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 fund the portion of net periodic costs for post-retirement benefits included in our prices.

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,	2012	2011	2012	2011
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 876,308	$ 747,460	$ 150,078	$ 137,759
Service cost	19,556	16,076	2,057	1,803
Interest cost	39,576	40,045	6,298	6,793
Plan participants' contributions	—	—	2,987	3,390
Benefits paid (a)	(60,229)	(31,107)	(9,799)	(10,114)
Actuarial losses (gains)	53,497	94,161	943	5,246
Amendments	—	—	—	4,451
Other (b)	—	9,673	—	750
Benefit obligation, end of year (c)	$ 928,708	$ 876,308	$ 152,564	$ 150,078
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 481,077	$ 432,233	$ 91,858	$ 86,984
Actual return on plan assets	67,328	27,819	10,673	(174)
Employer contributions	56,700	50,000	10,803	10,793
Plan participants' contributions	—	—	2,845	3,244
Benefits paid (a)	(57,174)	(28,975)	(9,386)	(9,739)
Other (b)	—	—	—	750
Fair value of plan assets, end of year	$ 547,931	$ 481,077	$ 106,793	$ 91,858
Funded status, end of year	$ (380,777)	$ (395,231)	$ (45,771)	$ (58,220)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (2,870)	$ (2,741)	$ (298)	$ (115)
Noncurrent liability	(377,907)	(392,490)	(45,473)	(58,105)
Net amount recognized	$ (380,777)	$ (395,231)	$ (45,771)	$ (58,220)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 383,365	$ 397,691	$ 12,436	$ 18,178
Prior service cost	3,994	4,606	16,467	18,991
Transition obligation	—	—	325	4,236
Net amount recognized	$ 387,359	$ 402,297	$ 29,228	$ 41,405

(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, 2011, Other includes the $9.7 million reclassification of a contractual obligation related to the legal settlement with a former executive officer and $0.8 million of proceeds received as a result of the Early Retiree Reinsurance Program.
(c) As of December 31, 2012 and 2011, pension benefits include non-qualified benefit obligations of $30.0 million and $29.4 million, respectively, which are funded by a trust containing assets of $43.5 million and $40.2 million, respectively, classified as trading securities as discussed in Notes 4 and 5, "Financial and Derivative Instruments, Trading Securities, Energy marketing and Risk Management" and "Financial Investments," respectively.

As of December 31,	Pension Benefits 2012	Pension Benefits 2011	Post-retirement Benefits 2012	Post-retirement Benefits 2011
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 928,708	$ 876,308	$ —	$ —
Fair value of plan assets	547,931	481,077	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 806,888	$ 750,263	—	—
Fair value of plan assets	547,931	481,077	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	—	—	$ 152,564	$ 150,078
Fair value of plan assets	—	—	106,793	91,858
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	4.13%	4.50%	3.99%	4.25%
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 (benefit) 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 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			Post-retirement Benefits		
Year Ended December 31,	2012	2011	2010	2012	2011	2010
	(Dollars in Thousands)					
Components of Net Periodic Cost (Benefit):						
Service cost	$ 19,556	$ 16,076	$ 13,926	$ 2,057	$ 1,803	$ 1,526
Interest cost	39,576	40,045	39,391	6,298	6,793	7,083
Expected return on plan assets	(32,283)	(31,087)	(38,384)	(5,491)	(5,002)	(5,197)
Amortization of unrecognized:						
Transition obligation, net	—	—	—	3,912	3,911	3,912
Prior service costs	612	1,213	2,729	2,524	2,524	2,154
Actuarial loss/(gain), net	32,778	23,659	17,183	1,503	702	321
Net periodic cost before regulatory adjustment	60,239	49,906	34,845	10,803	10,731	9,799
Regulatory adjustment (a)	(6,523)	(22,098)	(12,167)	23	1,344	1,868
Net periodic cost	$ 53,716	$ 27,808	$ 22,678	$ 10,826	$ 12,075	$ 11,667
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$ 18,451	$ 97,429	$ 65,690	$ (4,239)	$ 10,421	$ 3,298
Amortization of actuarial (loss)/gain	(32,778)	(23,659)	(17,183)	(1,503)	(702)	(321)
Current year prior service cost	—	—	676	—	4,451	—
Amortization of prior service costs	(612)	(1,213)	(2,729)	(2,524)	(2,524)	(2,154)
Amortization of transition obligation	—	—	—	(3,912)	(3,911)	(3,912)
Total recognized in regulatory assets	$ (14,939)	$ 72,557	$ 46,454	$ (12,178)	$ 7,735	$ (3,089)
Total recognized in net periodic cost and regulatory assets	$ 38,777	$ 100,365	$ 69,132	$ (1,352)	$ 19,810	$ 8,578
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):						
Discount rate	4.50%	5.35%	5.95%	4.25%	5.00%	5.65%
Expected long-term return on plan assets	6.50%	6.50%	8.25%	6.00%	6.00%	7.75%
Compensation rate increase	4.00%	4.00%	4.00%	—	—	—

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

We estimate that we will amortize the following amounts from regulatory assets into net periodic cost in 2013.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 33,914	$ 1,125
Prior service cost	601	2,524
Transition obligation	—	325
Total	$ 34,515	$ 3,974

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,	
	2012	2011
Health care cost trend rate assumed for next year	8.0%	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	2018

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	$ 67	$ (64)
Effect on post-retirement benefit obligation	1,489	(1,384)

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.

The target allocations for our pension plan assets are about 44% to debt securities, 42% to equity securities and the remaining 14% to other investments such as real estate securities, hedge funds and private equity investments. 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.

The 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 and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management," 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 $35.6 million as of December 31, 2012, invested directly in long-term U.S. Treasury securities. We also maintain certain level 3 investments in private equity, real estate securities and alternative funds that require significant unobservable market information to measure the fair value of the investments. The fair value of private equity investments is measured by utilizing both market- and income-based models, public company comparables, at cost or at 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. To measure the fair value of real estate securities we use a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity. Alternative funds are measured at fair value using net asset values as reported by the alternative fund managers. Since the underlying assets in alternative funds vary widely various methods are required, often utilizing significant management judgment.

The following table provides the fair value of our pension plan assets and the corresponding level of hierarchy as of December 31, 2012 and 2011.

As of December 31, 2012	Level 1	Level 2	Level 3	Total
	(In Thousands)			
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
Real estate securities	—	—	20,927	20,927
Alternative funds	—	—	45,535	45,535
Cash equivalents	—	2,852	—	2,852
Total Assets Measured at Fair Value	$ —	$ 462,976	$ 84,955	$ 547,931
As of December 31, 2011				
Assets:				
Domestic equity	$ —	$ 121,364	$ 15,375	$ 136,739
International equity	—	53,943	—	53,943
Core bonds	—	142,700	—	142,700
High-yield bonds	—	38,380	—	38,380
Combination debt/equity fund	—	47,151	—	47,151
Real estate securities	—	—	18,848	18,848
Alternative funds	—	—	40,716	40,716
Cash equivalents	—	2,600	—	2,600
Total Assets Measured at Fair Value	$ —	$ 406,138	$ 74,939	$ 481,077

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, 2012 and 2011.

	Domestic Equity	High-yield Bonds	Real Estate Securities	Alternative Funds	Total
	(In Thousands)				
Balance as of December 31, 2011	$ 15,375	$ —	$ 18,848	$ 40,716	$ 74,939
Actual gain (loss) on plan assets:					
Relating to assets still held at the reporting date	(25)	—	2,296	4,819	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	$ —	$ 20,927	$ 45,535	$ 84,955
Balance as of December 31, 2010	$ 11,575	$ 1,200	$ 16,411	$ 25,764	$ 54,950
Actual gain (loss) on plan assets:					
Relating to assets still held at the reporting date	1,910	—	2,652	(48)	4,514
Relating to assets sold during the period	—	—	(49)	—	(49)
Purchases, issuances and settlements, net	1,890	(1,200)	(166)	15,000	15,524
Balance as of December 31, 2011	$ 15,375	$ —	$ 18,848	$ 40,716	$ 74,939

The following table provides the fair value of our post-retirement benefit plan assets and the corresponding level of hierarchy as of December 31, 2012 and 2011.

As of December 31, 2012	Level 1	Level 2	Level 3	Total
	(In Thousands)			
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
As of December 31, 2011				
Assets:				
Domestic equity	$ —	$ 47,411	$ —	$ 47,411
International equity	—	11,500	—	11,500
Core bonds	—	32,192	—	32,192
Cash equivalents	—	755	—	755
Total Assets Measured at Fair Value	$ —	$ 91,858	$ —	$ 91,858

Cash Flows

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

Expected Cash Flows	Pension Benefits		Post-retirement Benefits	
	To/(From) Trust	(From) Company Assets	To/(From) Trust	(From) Company Assets
	(In Millions)			
Expected contributions:				
2013	$ 30.0		$ 6.0	
Expected benefit payments:				
2013	$ (31.3)	$ (2.9)	$ (7.9)	$ (0.3)
2014	(33.3)	(2.8)	(8.3)	(0.3)
2015	(35.3)	(2.8)	(8.8)	(0.3)
2016	(38.0)	(2.8)	(9.1)	(0.3)
2017	(41.1)	(2.8)	(9.5)	(0.3)
2018 - 2022	(247.1)	(13.0)	(49.6)	(1.2)

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 plans are deposited with a trustee and invested at the direction of plan participants into one or more of the investment alternatives we provide under the plan. Our contributions totaled $7.1 million in 2012, $7.0 million in 2011 and $7.4 million in 2010.

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, 2012, awards of approximately 4.8 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,		
	2012	2011	2010
	(In Thousands)		
Compensation expense	$ 7,203	$ 8,367	$ 11,321
Income tax benefits related to stock-based compensation arrangements	2,849	3,309	4,481

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 2012 valuation, inputs for expected volatility ranged from 17.6% to 33.6% and the risk-free interest rate was approximately 0.4%. For the 2011 valuation, inputs for expected volatility and risk-free interest rates ranged from 24.5% to 28.5% and 0.1% to 1.3%, respectively. 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, 2012, 2011 and 2010, our RSU activity for awards with only service requirements was as follows:

	As of December 31,					
	2012		2011		2010	
	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	368.5	$ 23.83	600.4	$ 21.50	368.8	$ 21.98
Granted	131.0	27.82	284.1	26.30	366.4	22.14
Vested	(127.8)	23.34	(187.3)	23.50	(118.1)	24.81
Forfeited	(20.6)	24.40	(328.7)	24.37	(16.7)	22.32
Nonvested balance, end of year	351.1	25.47	368.5	23.83	600.4	21.50

Total unrecognized compensation cost related to RSU awards with only service requirements was $4.2 million as of December 31, 2012. 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, 2012, 2011 and 2010, was $3.7 million, $4.8 million and $2.7 million, respectively.

During the years ended December 31, 2012, 2011 and 2010, our RSU activity for awards with performance measures was as follows:

	As of December 31,					
	2012		2011		2010	
	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	324.2	$ 28.31	348.4	$ 24.98	—	$ —
Granted	122.3	28.84	244.4	31.26	366.0	24.96
Vested	(88.2)	25.46	(119.5)	24.12	(4.5)	23.32
Forfeited	(18.2)	29.00	(149.1)	28.72	(13.1)	24.99
Nonvested balance, end of year	340.1	29.20	324.2	28.31	348.4	24.98

As of December 31, 2012 and 2011, total unrecognized compensation cost related to RSU awards with performance measures was $3.5 million and $3.3 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, 2012 and 2011, was $3.6 million. No performance RSUs vested in 2010.

Stock options granted between 1998 and 2001 are completely vested and have expired. There were no options exercised and all remaining options were forfeited during the year ended December 31, 2010. We currently have no plans to issue new stock option awards.

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 666 shares of common stock for dividends in 2012, 4,757 shares in 2011 and 6,627 shares in 2010. Participants received common stock distributions of 1,461 shares in 2012, 67,426 shares in 2011 and 1,198 shares in 2010.

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.

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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,	2012	2011	2012	2011
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 161,396	$ 131,460	$ 10,129	$ 10,144
Service cost	6,062	4,957	191	165
Interest cost	7,537	7,370	411	458
Plan participants’ contributions	—	—	608	614
Benefits paid (a)	(8,569)	(3,033)	(988)	(979)
Actuarial losses (gains)	9,815	20,642	669	(360)
Amendments	650	—	—	—
Other (b)	—	—	—	87
Benefit obligation, end of year	$ 176,891	$ 161,396	$ 11,020	$ 10,129
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 80,727	$ 76,086	$ 4	$ —
Actual return on plan assets	11,764	(2,578)	—	—
Employer contributions	13,887	10,009	389	369
Plan participants' contributions	—	—	608	614
Benefits paid	(8,327)	(2,790)	(988)	(979)
Fair value of plan assets, end of year	$ 98,051	$ 80,727	$ 13	$ 4
Funded status, end of year	$ (78,840)	$ (80,669)	$ (11,007)	$ (10,125)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (243)	$ (243)	$ (625)	$ (609)
Noncurrent liability	(78,597)	(80,426)	(10,382)	(9,516)
Net amount recognized	$ (78,840)	$ (80,669)	$ (11,007)	$ (10,125)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 64,535	$ 65,273	$ 3,643	$ 3,208
Prior service cost	675	31	—	—
Transition obligation	—	—	1	58
Net amount recognized	$ 65,210	$ 65,304	$ 3,644	$ 3,266

(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.
(b) Includes proceeds received as a result of the Early Retiree Reinsurance Program.

As of December 31,	Pension Benefits 2012	Pension Benefits 2011	Post-retirement Benefits 2012	Post-retirement Benefits 2011
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 176,891	$ 161,396	$ —	$ —
Fair value of plan assets	98,051	80,727	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 141,722	$ 128,633	$ —	$ —
Fair value of plan assets	98,051	80,727	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 11,020	$ 10,129
Fair value of plan assets	—	—	13	4
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	4.16%	4.55%	3.78%	4.10%
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.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2012	2011	2010	2012	2011	2010
	(Dollars in Thousands)					
Components of Net Periodic Cost (Benefit):						
Service cost	$ 6,062	$ 4,957	$ 4,144	$ 191	$ 165	$ 179
Interest cost	7,537	7,370	6,941	411	458	519
Expected return on plan assets	(6,577)	(5,904)	(5,453)	—	—	—
Amortization of unrecognized:						
Transition obligation, net	—	52	57	57	58	58
Prior service costs	6	16	29	—	—	—
Actuarial loss, net	5,366	3,586	2,636	234	227	276
Net periodic cost before regulatory adjustment	12,394	10,077	8,354	893	908	1,032
Regulatory adjustment (a)	(1,776)	(2,546)	(1,498)	—	—	—
Net periodic cost	$ 10,618	$ 7,531	$ 6,856	$ 893	$ 908	$ 1,032
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$ 4,629	$ 29,124	$ 7,514	$ 669	$ (360)	$ 363
Amortization of actuarial loss	(5,366)	(3,586)	(2,636)	(234)	(227)	(276)
Current year prior service cost	650	—	—	—	—	—
Amortization of prior service cost	(6)	(16)	(29)	—	—	—
Amortization of transition obligation	—	(52)	(57)	(57)	(58)	(58)
Total recognized in regulatory assets	$ (93)	$ 25,470	$ 4,792	$ 378	$ (645)	$ 29
Total recognized in net periodic cost and regulatory assets	$ 10,525	$ 33,001	$ 11,648	$ 1,271	$ 263	$ 1,061
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:						
Discount rate	4.55%	5.45%	6.05%	4.10%	4.90%	5.50%
Expected long-term return on plan assets	7.50%	7.50%	8.00%	—	—	—
Compensation rate increase	4.00%	4.00%	4.00%	—	—	—

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

We estimate that we will amortize the following amounts from regulatory assets into net periodic cost in 2013.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 5,421	$ 264
Prior service cost	58	—
Transition obligation	—	1
Total	$ 5,479	$ 265

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,	
	2012	2011
Health care cost trend rate assumed for next year	8.0%	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	2018

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	$ (10)	$ 10
Effect on post-retirement benefit obligation	(129)	128

Plan Assets

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. See Note 4, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management," 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, 2012 and 2011.

As of December 31, 2012	Level 1	Level 2	Level 3	Total
	(In Thousands)			
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
As of December 31, 2011				
Assets:				
Domestic equity	$ 30,753	$ —	$ —	$ 30,753
International equity	9,953	8,070	—	18,023
Core bonds	—	17,877	—	17,877
High-yield bonds	4,102	—	—	4,102
Real estate securities	—	—	3,630	3,630
Commodities	—	4,377	—	4,377
Cash equivalents	—	1,965	—	1,965
Total Assets Measured at Fair Value	$ 44,808	$ 32,289	$ 3,630	$ 80,727

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, 2012 and 2011.

	Real Estate Securities	Alternative Investments	Total
	(In Thousands)		
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
Balance as of December 31, 2010	$ 3,160	$ —	$ 3,160
Actual gain (loss) on plan assets:			
Relating to assets still held at the reporting date	500	—	500
Relating to assets sold during the period	2	—	2
Purchases, issuances and settlements, net	(32)	—	(32)
Balance as of December 31, 2011	$ 3,630	$ —	$ 3,630

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.

Expected Cash Flows	Pension Benefits		Post-retirement Benefits	
	To/(From) Trust	(From) Company Assets	To/(From) Trust	(From) Company Assets
	(In Millions)			
Expected contributions:				
2013	$ 9.4		$ 0.6	
Expected benefit payments:				
2013	$ (3.7)	$ (0.2)	$ (0.6)	$ —
2014	(4.3)	(0.2)	(0.7)	—
2015	(5.0)	(0.2)	(0.7)	—
2016	(5.8)	(0.2)	(0.8)	—
2017	(6.7)	(0.2)	(0.8)	—
2018 - 2022	(46.9)	(0.9)	(4.5)	—

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 $1.3 million in 2012, $1.3 million in 2011 and $1.1 million in 2010.

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," that had an unexpended balance of approximately $588.3 million as of December 31, 2012, of which $278.1 million had been committed. 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, 2012, was as follows.

	Committed Amount
	(In Thousands)
2013	$ 159,546
2014	72,573
2015	29,271
Thereafter	16,727
Total amount committed	$ 278,117

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 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.

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 PM, NOx, 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 PM. The EPA anticipates making initial attainment/nonattainment designations under this rule by the end of 2014. 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. 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 cost associated with our approximately $610.0 million share of the projected capital investment associated with the $1.2 billion of environmental upgrades at La Cygne. We therefore must file for a general review of our rates or an abbreviated rate review with the KCC in order to collect these costs. As previously discussed, the KCC approved our request to file an abbreviated rate review within 12 months of the April 2012 order to update our prices to include capital costs related to environmental projects at La Cygne. 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 2011, the EPA published Mercury and Air Toxics Standards for power plants, which replaces the prior federal Clean Air Mercury Rule and requires significant reductions in mercury, acid gases and other emissions. Companies impacted by the new standards will have up to three years, or four years with approval from a state environmental regulatory agency, and in certain limited circumstances up to five years, to comply. We have obtained approval from our state environmental regulatory agency and expect to be compliant with the new standards within four years. We continue to evaluate the new standards and believe that our related investment will be less than $16.0 million.

In mid 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. Under CSAPR, reductions in annual SO_2 and NOx emissions were required to begin January 2012, with further reductions required beginning January 2014. The EPA also published a final supplemental rule to CSAPR later in 2011 requiring five states, including Missouri and Oklahoma, to make summertime reductions in NOx emissions beginning in May 2012. Although Kansas was included in the original proposed rule, the final supplemental rule instead called for the EPA to revisit Kansas' status once Kansas submitted an ozone state implementation plan. 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. In October 2012, the EPA filed a petition with the court requesting a rehearing before the full court. In January 2013, the court issued orders declining to rehear the case. We cannot at this time predict how the EPA may proceed with rulemaking; 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.

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 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 and contribute toward meeting the increased requirements beginning in 2016. 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 $240.0 million. The settlement also required that we determine whether we needed to install additional SCR equipment on another JEC unit or if we can meet agreed upon plant-wide NOx emissions reduction limits using other controls. We have informed the EPA that we believe we can meet the terms of the settlement by installing less expensive NOx reduction equipment rather than additional SCR equipment. 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 and 2011, we had recorded a liability of $1.6 million and $0.5 million, respectively, 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 resulting in payments totaling $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 $3.2 million in 2012, $3.2 million in 2011 and $3.1 million in 2010. We record our investment in the NDT fund at fair value, which approximated $150.8 million and $130.3 million as of December 31, 2012 and 2011, 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 $3.6 million in 2012, $3.1 million in 2011 and $4.0 million in 2010. We include these costs in fuel and purchased power expense on our consolidated statements of income.

In 2010, the DOE filed a motion with the NRC to withdraw its then pending application to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada. An NRC board denied the DOE's motion to withdraw its application and the DOE appealed that decision to the full NRC. In 2011, the NRC issued an evenly split decision on the appeal and also ordered the licensing board to close out its work on the DOE's application by the end of 2011 due to a lack of funding. These agency actions prompted the States of Washington and South Carolina, and a county in South Carolina, to file a lawsuit in a federal Court of Appeals asking the court to compel the NRC to resume its license review and to issue a decision on the license application. In August 2012, the court ordered the parties to report to it, no later than December 14, 2012 (later extended to January 4, 2013), whether Congress had provided funding for the NRC to proceed on the license application. By that date, Congress had not yet provided funding, and the parties filed their respective status reports and arguments on whether or not the court should order the NRC to resume its license review. The court has not yet acted on the pending request. 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 insurance for Wolf Creek in four areas: liability, worker radiation, property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear and war. The nuclear liability program subscribed to by members of the nuclear power generating industry no longer include industry aggregate limits for non-certified acts, as defined by the Terrorism Risk Insurance Act, of terrorism-related losses. An industry aggregate limit of $3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), our insurance provider, exists for property claims, including accidental outage power costs, for acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within 12 months from the date of the first act. These limits are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. 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 full limit of public liability, which is currently approximately $12.6 billion. This limit of liability consists of the maximum available commercial insurance of $375.0 million and the remaining $12.2 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, the owners of Wolf Creek are jointly and severally subject to an assessment of up to $117.5 million (our share is $55.2 million), payable at no more than $17.5 million (our share is $8.2 million) per incident per year per reactor. Both the total and yearly assessment is subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. This assessment also applies in excess of our worker radiation claims insurance. The next inflation adjustment is scheduled for 2013. In addition, Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property 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 (our share is $1.3 billion). This insurance is provided by NEIL. 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, decontamination expenses or, if certain requirements are met, including nuclear decommissioning the plant, toward a shortfall in the NDT fund.

Accidental Nuclear Outage Insurance

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, the owners of Wolf Creek may be subject to retrospective assessments under the current policies of approximately $30.2 million (our share is $14.2 million).

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, 2012, our share of Wolf Creek's nuclear fuel commitments was approximately $42.2 million for uranium concentrates expiring in 2017, $6.3 million for conversion expiring in 2017, $106.3 million for enrichment expiring in 2025 and $36.0 million for fabrication expiring in 2023.

As of December 31, 2012, our coal and coal transportation contract commitments under the remaining terms of the contracts were approximately $648.2 million. The contracts are for plants that we operate and expire at various times through 2021.

As of December 31, 2012, our natural gas transportation contract commitments under the remaining terms of the contracts were approximately $129.0 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 four separate wind generation facilities with installed design capacities of 515 MW. The agreements expire in 2028 through 2032. 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 beginning in 2013.

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, 2012, we are committed to spend approximately $34.3 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,	
	2012	2011
	(In Thousands)	
Beginning ARO	$ 142,508	$ 125,999
Liabilities settled	(1,389)	(1,027)
Accretion expense	8,454	7,623
Increase in nuclear decommissioning ARO liability	—	9,913
Revisions in estimated cash flows	3,075	—
Ending ARO	$ 152,648	$ 142,508

As discussed in Note 13, "Commitments and Contingencies—Nuclear Decommissioning," Wolf Creek filed a nuclear decommissioning study with the KCC in 2011. As a result of the study, we recorded a $9.9 million increase in our ARO to reflect revisions to the estimated costs to decommission Wolf Creek.

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

We have an obligation to retire our wind generation facilities and remove the foundations. The ARO related to our 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, 2012 and 2011, we had $129.0 million and $82.3 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 May 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, 2012 and 2011, Westar Energy had issued 126.5 million shares and 125.7 million shares, respectively.

Westar Energy has a direct stock purchase plan (DSPP). Shares of common stock sold pursuant to the DSPP may be either original issue shares or shares purchased in the open market. During 2012, 2011 and 2010, Westar Energy issued 0.8 million shares, 0.8 million shares and 0.7 million shares, respectively, through the DSPP and other stock-based plans operated under the LTISA Plan. As of December 31, 2012 and 2011, a total of 1.5 million shares and 2.0 million shares, respectively, were available under the DSPP registration statement.

Issuances

In April 2010, Westar Energy entered into a three-year Sales Agency Financing Agreement and forward sale agreement with a bank. The maximum amount that Westar Energy may offer and sell under the agreements is 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 may offer and sell shares of its common stock from time to time through the broker dealer subsidiary, as agent. The broker dealer receives 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 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 broker dealer. Westar Energy must settle the forward sale transactions within 18 months of the date each transaction is 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 2012, Westar Energy entered into additional forward sale transactions with respect to an aggregate of approximately 1.8 million shares of common stock. Assuming physical share settlement of these forward sale transactions as of December 31, 2012, Westar Energy would have received aggregate proceeds of approximately $48.1 million based on a forward price of $27.45 per share.

In November 2010, Westar Energy entered into a separate forward sale agreement with a bank. Under the terms of the agreement, the bank, as forward seller, borrowed 7.5 million shares of Westar Energy's common stock from third parties and sold them to a group of underwriters for $25.54 per share. Under an over-allotment option included in the agreement, the underwriters purchased approximately 1.0 million additional shares for $25.54 per share, increasing the total number of shares under the forward sale agreement to approximately 8.5 million shares. The underwriters received a commission equal to 3.5% of the sales price of all shares sold under the agreement. In November 2011, Westar Energy delivered approximately 8.5 million shares of common stock for proceeds of approximately $197.3 million as complete settlement of this forward sale agreement.

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. 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

Under two separate agreements that expire in May 2013 and November 2014, we lease railcars from trusts to transport coal to some of our power plants. The trusts were financed with equity contributions from owner participants and debt issued by the trusts. The trusts were created specifically to purchase the railcars and lease them to us, and do not hold any other assets. We meet the requirements to be considered the primary beneficiary of the trusts. In determining the primary beneficiary of the trusts, we concluded that the activities of the trusts that most significantly impact their 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 trusts that could potentially be significant if the fair value of the railcars at the end of the agreements is greater than the fixed amounts. Our agreements with these trusts also include renewal options during which time we would pay a fixed amount of rent. We have the potential to receive benefits from the trusts during the renewal periods 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,	
	2012	2011
	(In Thousands)	
Assets:		
Property, plant and equipment of variable interest entities, net	$ 321,975	$ 333,494
Regulatory assets (a)	5,810	4,915
Liabilities:		
Current maturities of long-term debt of variable interest entities	$ 25,942	$ 28,114
Accrued interest (b)	3,948	4,448
Long-term debt of variable interest entities, net	222,743	249,283

(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:		
2010	$	15,464
2011		17,577
2012		17,080
Future commitments:		
2013	$	14,453
2014		12,550
2015		10,142
2016		8,390
2017		6,694
Thereafter		18,049
Total future commitments	$	70,278

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.

In 2011, FERC issued an order approving a power supply agreement. The agreement extends through May 2039 and the terms meet the criteria to be classified as a capital lease. Accordingly, we recorded a $40.0 million capital lease in 2011.

Assets recorded under capital leases, including the 2012 and 2011 leases described above presented as generation plant, are listed below.

	As of December 31,			
	2012		2011	
	(In Thousands)			
Vehicles	$	12,594	$	14,241
Computer equipment		1,423		1,720
Generation plant		48,346		40,048
Accumulated amortization		(6,928)		(6,485)
Total capital leases	$	55,435	$	49,524

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)
2013	$ 6,538
2014	6,363
2015	5,840
2016	5,087
2017	4,708
Thereafter	76,800
	105,336
Amounts representing imputed interest	(48,461)
Present value of net minimum lease payments under capital leases	56,875
Less: Current portion	3,066
Total long-term obligation under capital leases	$ 53,809

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.

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.

2011	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues (a)	$ 481,720	$ 524,892	$ 678,152	$ 486,228
Net income (a)	32,957	45,525	136,392	21,306
Net income attributable to common stock (a)	31,342	43,887	134,708	19,335
Per Share Data (a):				
Basic:				
Earnings available	$ 0.27	$ 0.38	$ 1.15	$ 0.16
Diluted:				
Earnings available	$ 0.27	$ 0.38	$ 1.14	$ 0.16
Cash dividend declared per common share	$ 0.32	$ 0.32	$ 0.32	$ 0.32
Market price per common share:				
High	$ 26.60	$ 27.98	$ 27.29	$ 29.05
Low	$ 25.05	$ 25.58	$ 22.63	$ 25.02

(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.

There were no changes in our internal control over financial reporting during the three months ended December 31, 2012, 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 2013 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (2013 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 "Section 16(a) Beneficial Ownership Reporting Compliance" in our 2013 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 "Corporate Governance Matters" in our 2013 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 2013 Proxy Statement under the captions "Compensation Discussion and Analysis," "Compensation Committee Report," "Compensation of Executive Officers and Directors," "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 2013 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 2013 Proxy Statement under the caption "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 2013 Proxy Statement under the captions "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, 2012 and 2011
Consolidated Statements of Income for the years ended December 31, 2012, 2011 and 2010
Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010
Consolidated Statements of Changes in Equity for the years ended December 31, 2012, 2011 and 2010
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)	Underwriting Agreement, dated February 27, 2012, among Barclays Capital Inc., Mitsubishi UFJ Securities (USA), Inc. and Wells Fargo Securities, LLC as representatives of the several underwriters named therein, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on February 29, 2012)	I
1(b)	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(c)	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(d)	Underwriting Agreement, dated May 14, 2012, among BNP Paribas Securities Corp., Citigroup Global Markets Inc. and J.P. Morgan Securities LLC, as representatives of the several underwriters named therein, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on May 16, 2012)	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)	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
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, 2010				
Allowances deducted from assets for doubtful accounts	$ 5,231	$ 8,337	$ (7,839)	$ 5,729
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

(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 28, 2013	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 28, 2013
/s/ ANTHONY D. SOMMA (Anthony D. Somma)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	February 28, 2013
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 28, 2013
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 28, 2013
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 28, 2013
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 28, 2013
/s/ RICHARD L. HAWLEY (Richard L. Hawley)	Director	February 28, 2013
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 28, 2013
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	February 28, 2013
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 28, 2013
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	February 28, 2013
/s/ S. CARL SODERSTROM JR. (S. Carl Soderstrom Jr.)	Director	February 28, 2013

Exhibit 12(a)

WESTAR ENERGY, INC.
Computations of Ratio of Earnings to Fixed Charges and
Computations of Ratio of Earnings to Combined Fixed Charges
and Preferred Dividend Requirements
(Dollars in Thousands)

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Earnings from continuing operations (a)	$ 406,638	$ 339,274	$ 293,591	$ 200,226	$ 182,139
Fixed Charges:					
Interest (expensed and capitalized) (b)	186,736	178,049	179,272	162,217	126,986
Interest on corporate-owned life insurance borrowings	63,518	66,326	68,926	68,401	58,207
Interest applicable to rentals (b)	4,675	4,528	4,325	22,353	23,227
Total Fixed Charges (c)	254,929	248,903	252,523	252,971	208,420
Distributed income of equity investees	—	—	—	—	—
Preferred Dividend Requirements:					
Preferred dividends	1,616	970	970	970	970
Income tax required	723	424	396	404	22
Total Preferred Dividend Requirements (d)	2,339	1,394	1,366	1,374	992
Total Fixed Charges and Preferred Dividend Requirements	257,268	250,297	253,889	254,345	209,412
Earnings (e)	$ 661,567	$ 588,177	$ 546,114	$ 453,197	$ 390,559
Ratio of Earnings to Fixed Charges	2.60	2.36	2.16	1.79	1.87
Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements	2.57	2.35	2.15	1.78	1.87

(a) Earnings from continuing operations consist of income from continuing operations before income taxes, cumulative effects of accounting changes and preferred dividends adjusted for undistributed earnings from equity investees.

(b) As a result of consolidating variable interest entities as discussed in Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," amounts previously reported as interest applicable to rentals are reported as interest expense beginning in 2010.

(c) Fixed charges consist of all interest on indebtedness, interest on uncertain tax positions, interest on corporate-owned life insurance policies, amortization of debt discount and expense, and the portion of rental expense that represents an interest factor.

(d) Preferred dividend requirements consist of an amount equal to the pre-tax earnings that would be required to meet dividend requirements on preferred stock.

(e) Earnings are deemed to consist of earnings from continuing operations, fixed charges and distributed income of equity investees.

WESTAR ENERGY, INC.
Subsidiaries of the Registrant

Subsidiary	State of Incorporation	Date Incorporated
1) Kansas Gas and Electric Company (a)	Kansas	October 9, 1990

(a) Kansas Gas and Electric Company does business as Westar Energy.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-165889 on Form S-3, and Registration Statement Nos. 333-175293, 333-70891, and 333-151104 on Form S-8 of our reports dated February 28, 2013, relating to (1) the consolidated financial statements and financial statement schedule of Westar Energy, Inc. and subsidiaries, and (2) the effectiveness of Westar Energy, Inc. and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Westar Energy, Inc. for the year ended December 31, 2012.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 28, 2013

Exhibit 31(a)

WESTAR ENERGY, INC.
CHIEF EXECUTIVE OFFICER
CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark A. Ruelle, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2012, of Westar Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   a. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2013

By: /s/ Mark A. Ruelle

Mark A. Ruelle
Director, President and Chief Executive Officer
Westar Energy, Inc.
(Principal Executive Officer)

Exhibit 31(b)

WESTAR ENERGY, INC.
CHIEF FINANCIAL OFFICER
CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Anthony D. Somma, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2012, of Westar Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2013 By: /s/ Anthony D. Somma

Anthony D. Somma
Senior Vice President, Chief Financial Officer and Treasurer
Westar Energy, Inc.
(Principal Accounting Officer)

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Westar Energy, Inc. (the Company) on Form 10-K for the year ended December 31, 2012 (the Report), which this certification accompanies, Mark A. Ruelle, in my capacity as Director, President and Chief Executive Officer of the Company, and Anthony D. Somma, in my capacity as Senior Vice President, Chief Financial Officer and Treasurer of the Company, certify that the Report fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date:	February 28, 2013	By:	/s/ Mark A. Ruelle
			Mark A. Ruelle
			Director, President and Chief Executive Officer
Date:	February 28, 2013	By:	/s/ Anthony D. Somma
			Anthony D. Somma
			Senior Vice President, Chief Financial Officer and Treasurer