WESTAR ENERGY INC /KS
Form 10-K
February 23, 2012
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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, 2011
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
First Mortgage Bonds, 6.10% Series due 2047	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:
Preferred Stock, 4-1/2% Series, $100 par value
(Title of Class)
Indicate by check mark whether the registrant is a well-known seasoned issuer (as defined in Rule 405 of the Act). Yes X No
Indicate by check mark whether the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No X
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes X No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Act). Check one:
Large accelerated filer X Accelerated filer Non-accelerated filer Smaller reporting company

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $3,113,953,754 at June 30, 2011.

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	126,037,601 shares
(Class)	(Outstanding at February 15, 2012)

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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 2012 Annual Meeting of Shareholders	Part III (Item 10 through Item 14) (Portions of Item 10 are not incorporated by reference and are provided herein)

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GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
BACT	Best Available Control Technology
BNSF	BNSF Railway Company
Btu	British thermal units
CAMR	Clean Air Mercury Rule
CCB	Coal combustion byproduct
CO	Carbon monoxide
CO2	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
DOJ	Department of Justice
DSPP	Direct Stock Purchase Plan
ECRR	Environmental Cost Recovery Rider
EGU	Electric generating unit
EPA	Environmental Protection Agency
EPS	Earnings per share
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gas
INPO	Institute of Nuclear Power Operations
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
kV	Kilovolt
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
ONEOK	ONEOK, Inc.

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OTC	Over-the-counter
PCB	Polychlorinated biphenyl
PM	Particulate matter
PRB	Powder River Basin
Protection One	Protection One, Inc.
PSD	Prevention of Significant Deterioration program
RCRA	Resource Conservation and Recovery Act
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
SO2	Sulfur dioxide
SPP	Southwest Power Pool
SSCGP	Southern Star Central Gas Pipeline
VaR	Value-at-Risk
VIE	Variable interest entity
Wolf Creek	Wolf Creek Generating Station

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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,
- 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,
- reduced demand for coal-based energy because of potential climate impacts and development of alternate energy sources,
- current and future litigation, regulatory investigations, proceedings or inquiries,

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- 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.

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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 688,000 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 are making environmental upgrades to our coal-fired power plants, developing renewable generation, and building and upgrading transmission facilities, in addition to developing systems and programs to help customers use energy more efficiently. Following is a summary of recent progress we have made on significant elements of our strategy.

- During 2011, we invested $220.0 million at our power plants to reduce regulated emissions.
- We have entered into two separate agreements with third parties to purchase under 20-year supply contracts renewable energy produced from approximately 370 megawatts (MW) of wind generation beginning in late 2012. These contracts, along with our prior development of wind generation, will provide for approximately 670 MW of total wind generation, which satisfies present statutory requirements.
- In late 2011, we began installing advanced metering infrastructure for SmartStar Lawrence. The project will enable customers to better monitor their energy use. We qualified to receive a matching grant of approximately $19.0 million from the Department of Energy (DOE). We expect to complete equipment installation in early 2012 and anticipate total project costs of approximately $39.3 million.

Our plans and expectations for 2012 and beyond are as follows.

- We plan to invest approximately $1.0 billion at our power plants over the next three years to reduce regulated emissions.
- We expect to complete construction of a 50-mile 345 kilovolt (kV) transmission line in south central Kansas in mid 2012.
- Prairie Wind Transmission, LLC, a joint venture company of which we own 50%, has under development 110 miles of transmission facilities running from near Wichita, Kansas, southwest to a location near Medicine Lodge, Kansas, and then south to the Oklahoma border. The project is scheduled for completion in 2014.
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In addition to the transmission lines described above, subject to regulatory approvals, we intend to make further investments to strengthen and improve Kansas' electrical transmission network.

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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. In addition, we engage in energy marketing, and purchase and sell electricity in the wholesale market.

Following is the percentage of our revenues by 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,					
	2011		2010		2009	
Residential	32	%	32	%	31	%
Commercial	28	%	28	%	28	%
Industrial	16	%	16	%	16	%
Wholesale	16	%	16	%	17	%
Transmission	7	%	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,					
	2011		2010		2009	
Residential	35	%	35	%	34	%
Commercial	37	%	38	%	39	%
Industrial	28	%	27	%	27	%
Total	100	%	100	%	100	%

Generation Capacity

We have 6,784 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 5 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	3,452	51	%	21,183,939	77	%
Nuclear	547	8	%	3,439,880	13	%
Natural gas, oil, diesel	2,780	41	%	2,305,034	8	%
Wind	5	<1		454,036	2	%
Total	6,784	100	%	27,382,889	100	%

In addition to owning and leasing the generating capacity identified in the table above, we also have two agreements under which we purchase wind generation from facilities with an installed design capacity totaling 146 MW. In 2011, we purchased 425,370 megawatt hours (MWh) of energy under these agreements.

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Our aggregate 2011 peak system net load of 5,549 MW occurred on August 2, 2011. 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 2011 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
Mid-Kansas Electric Company, LLC	173	January 2019
Kansas Power Pool	50	March 2020
Midwest Energy, Inc.	150	May 2025
Other	8	December 2013 – May 2015
Total	637	

(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 2011, 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.

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 2011 fuel mix was 79% coal, 12% nuclear and 9% natural gas, with diesel and oil 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 2,179 MW, of which we own or consolidate through a variable interest entity (VIE) a combined 92% share, or 2,005 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 next re pricing for those quantities over the scheduled annual minimum will occur in 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. 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 2011 was approximately $1.69 per MMBtu, or $27.82 per ton.

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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 unit 1 uses a blended fuel mix containing approximately 90% PRB coal and 10% local coal, the latter of which is purchased from time to time from Kansas and Missouri producers. La Cygne unit 2 uses exclusively PRB coal. The operator of La Cygne, Kansas City Power & Light Company (KCPL), arranges coal purchases and transportation services for La Cygne. Approximately 100% of La Cygne unit 1 and unit 2 PRB coal requirements is under contract for 2012. Approximately 95% of the 2013 requirements, 80% of the 2014 requirements and 20% of the 2015 requirements are also under contract. About 90% of those commitments are fixed price contracts. 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. As the PRB coal contracts expire, we anticipate that KCPL will negotiate new supply contracts or purchase coal on the spot market.

During 2011, the average delivered cost of our share of coal consumed at La Cygne unit 1 was approximately $1.98 per MMBtu, or $33.64 per ton. The average delivered cost of our share of coal consumed at La Cygne unit 2 was approximately $1.80 per MMBtu, or $30.90 per ton.

Lawrence and Tecumseh Energy Centers: Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 736 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 2012. BNSF transports coal for these energy centers under a contract that expires in December 2013.

During 2011, the average delivered cost of coal consumed in the Lawrence units was approximately $1.80 per MMBtu, or $31.89 per ton. The average delivered cost of coal consumed in the Tecumseh units was approximately $1.72 per MMBtu, or $30.68 per ton.

Natural Gas

We use natural gas as a primary fuel at our Gordon Evans, Murray Gill, Neosho, Abilene, 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 2011, we consumed 25.4 million MMBtu of natural gas for a total cost of $122.0 million, or approximately $4.81 per MMBtu. Natural gas accounted for approximately 9% of the total MMBtu of fuel we consumed and approximately 22% of our total fuel expense in 2011. 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 natural gas transportation arrangements for Abilene and Hutchinson Energy Centers with Kansas Gas Service. Abilene Energy Center is covered under a standard tariff as a large industrial transportation customer while Hutchinson Energy Center is covered under a rate agreement that 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 natural gas 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 1, 2016, 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 natural gas transportation agreement with ONEOK Gas Transportation, LLC.

Diesel and Oil

Once started with natural gas, the steam units at our Gordon Evans, Murray Gill, Neosho and Hutchinson Energy Centers have the capability to burn No. 6 oil or natural gas. Due to the environmental impact of burning No. 6 oil, we use No. 6 oil when natural gas is unavailable.

We also 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, satisfy emergency requirements and protect against the possibility of reduced availability of natural gas for limited periods.

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During 2011, we consumed 0.2 million MMBtu of diesel at a total cost of $4.4 million. Diesel accounted for less than 1% of our total MMBtu of fuel consumed and approximately 1% of our total fuel expense in 2011.

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, which represents 8% of our total generating capacity. 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.

Fuel Supply

Wolf Creek has on hand or under contract all of the uranium and conversion services needed to operate through March 2014 and approximately 78% of the uranium and conversion services needed after that date through March 2020. The owners also have under contract all of the uranium enrichment and fabrication services required to operate Wolf Creek through March 2026. All such agreements have been entered into in the ordinary course of business.

Outages

Wolf Creek operates on an 18-month planned refueling and maintenance outage schedule. The next outage is scheduled for fall 2012. During outages at the plant, we meet our electric demand primarily with our other generating units and by purchasing power. As authorized by regulators, we defer and amortize to expense ratably over an 18-month operating cycle the incremental maintenance costs incurred for planned refueling and maintenance outages.

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.

The NRC evaluates, monitors and rates various inspection findings and performance indicators for Wolf Creek based on their 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 mandates that our capacity consists of a certain amount of renewable sources. For us, wind has been the primary source of renewable energy. During 2011, our wind generation facilities produced 454,036 MWh of electricity and we purchased an additional 425,370 MWh of renewable energy from wind generation facilities through purchase power agreements. In addition, we have entered into two separate agreements with third parties to purchase under 20-year supply contracts the renewable energy produced from approximately 370 MW of wind generation beginning in late 2012.

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Other Fuel Matters

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

	2011	2010	2009
Per MMBtu:			
Nuclear	$0.68	$0.63	$0.47
Coal	1.74	1.56	1.51
Natural gas	4.81	5.12	4.22
Diesel/oil	19.33	15.76	15.58
All generating stations	1.92	1.70	1.58
Per MWh Generation:			
Nuclear	$7.15	$6.50	$4.87
Coal	19.30	17.45	16.79
Natural gas/diesel/oil	52.65	56.37	48.52
All generating stations	20.60	18.37	17.18

Our wind production has no fuel costs and is therefore excluded from the table above.

Purchased Power

We purchase electricity in addition to generating it. 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 own 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 2011, purchased power comprised approximately 15% of our total fuel and purchased power expense. Our weighted average cost of purchased power per MWh was $34.27 in 2011, $36.23 in 2010 and $35.62 in 2009.

Energy Marketing Activities

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.

Competition and Deregulation

The Federal Energy Regulatory Commission (FERC) requires owners of regulated transmission assets to allow third parties nondiscriminatory access to their transmission systems. FERC also requires us to provide transmission services to others on the same basis as we use those assets ourselves. Furthermore, FERC issued an order encouraging the formation of RTOs under which transmission service is aggregated and coordinated across broad regions to better enable competitive wholesale power markets.

Regional Transmission Organization

We are a member of the SPP, the RTO in our region. 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 its administrative expenses.

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Real-Time Energy Imbalance Market

The SPP 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 participate in this market.

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 certain 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 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 making and recovering expenditures. 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 power plants are overlapping, complex, subject to changes in interpretation and implementation, have become more stringent over time and are expensive to implement. Such laws and regulations relate primarily to discharges into the air, air quality, discharges of effluents into water, 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) and mercury.

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

Sulfur Dioxide

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 SO_2 we can emit. If we exceed these limits we could be subject to fines and penalties. In order to meet SO_2 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.

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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 2011, we had SO_2 allowances adequate to meet planned generation and we expect to have enough to cover emissions under this program in 2012. If we need to purchase additional air emission allowances in the future, our operating costs will increase. We collect, and expect to continue to collect, the cost of these allowances through the retail energy cost adjustment (RECA).

Cross-State Air Pollution Rule

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) which requires 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 1, 2012, with further reductions required beginning January 1, 2014. The EPA issued federal implementation plans for each state covered by CSAPR, but would allow these states to submit their own implementation plans starting as early as 2013.

In October 2011, the EPA issued a proposed amendment to CSAPR that, according to the EPA, would slightly ease the new emission standards and defer the effective date of certain penalty provisions from January 1, 2012, to January 1, 2014.

In December 2011, the EPA published a final supplemental rule to CSAPR requiring five states to make summertime reductions in NOx emissions under an ozone-season control program implemented under CSAPR. Reductions in ozone-season NOx under this rule begin May 1, 2012. Although Kansas was included in the original proposed rule, the final supplemental rule instead calls for the EPA to revisit Kansas' status under this supplemental rule once Kansas submits an ozone state implementation plan, which must occur within 12 to 18 months from the date the EPA issues a state implementation call to Kansas. The EPA has not yet issued such a call.

In October 2011, we filed legal challenges to CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the court issued its ruling to stay CSAPR, including the final supplemental rule, pending judicial review, which delays CSAPR's implementation date beyond January 1, 2012. The court is scheduled to hear the cases starting in April 2012. Under this timeframe, the court could issue its decision by summer or early fall 2012. As the outcome of the judicial review and any other possible legal or Congressional challenges are uncertain, we are unable to determine what impact CSAPR may ultimately have on our operations and consolidated financial results, but it could be material. See "Item 1A. Risk Factors" for additional information.

National Ambient Air Quality Standards

Under the federal Clean Air Act, the EPA sets National Ambient Air Quality Standards (NAAQS) for six criteria emissions considered harmful to public health and the environment, including PM, NOx, CO and SO_2, which result from coal combustion. Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS. NAAQS must be reviewed by the EPA at five-year intervals. In 2009, KDHE proposed to designate portions of the Kansas City area nonattainment for the 8-hour ozone standard, which has the potential to impact our operations.

In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. We 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.

PM, principally ash, is a byproduct of coal combustion. The EPA is currently reviewing the PM NAAQS. We cannot at this time predict the impact of this review and any possible new standards on our operations or consolidated financial results, but it could be material.

The EPA had been in the process of revising the NAAQS for ozone. However, in September 2011, the President of the United States ordered the EPA to withdraw its proposal. Work is currently underway to support the EPA's planned reconsideration of the standards in 2013.

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Mercury and Other Air Emissions

The operation of power plants results in emissions of mercury and other air toxics. In December 2011, the EPA finalized Mercury and Air Toxics Standards (MATS) for power plants, which replaces the prior federal Clean Air Mercury Rule (CAMR) and requires significant reductions in emissions of mercury and other air toxics. Companies impacted by the new standards will have up to four years, and in certain limited circumstances up to five years, to comply. We are currently evaluating the new standards and cannot at this time determine the impact they may have on our operations and consolidated financial results, but we believe the cost of compliance could be material.

Carbon Dioxide and 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 future. 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 December 2010, the EPA announced that it would be proposing GHG New Source Performance Standard (NSPS) rules for electric generating units (EGUs) and refineries. The rules will apply to new and existing facilities. The EPA had announced that it would propose the new rules by September 30, 2011, but has postponed the proposed rules for new and modified EGUs. It is unclear when the EPA will propose new rules for existing EGUs and how stringent they may be, but the rules are expected. Because these regulations have yet to be proposed or finalized, we cannot predict the impact they may have on our operations or consolidated financial results, but it could be material.

Under EPA regulations finalized in May 2010, 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: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications, which is referred to as the Prevention of Significant Deterioration program (PSD). Obligations relating to Title V permits include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors), are required to implement best available control technology (BACT). 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. The EPA is expected to issue a proposed rule in 2012 that may reduce the 75,000 and 100,000 ton thresholds noted above. 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.

Wastewater Effluent

Some water used in our operations is discharged as wastewater effluent. This wastewater may contain substances deemed to be pollutants. The EPA plans to propose revisions to the rules governing such wastewater effluent from coal-fired power plants by July 2012 with final action on the proposed rules expected to occur by January 2014. Although we cannot at this time determine the impact of any new regulations, more stringent regulations could have a material impact on our operations and consolidated financial results.

In April 2011, the EPA issued a proposed rule that would set stricter technology standards for cooling water intake structures at power plants. We are currently evaluating the proposal. The EPA is expected to finalize the proposal in

2012; however, because the rule has yet to be finalized, we cannot predict the impact it may have on our operations or consolidated financial results, but it could be material.

Regulation of Coal Combustion Byproducts

In the course of operating our coal generation plants, we produce coal combustion byproducts (CCBs), including fly ash and bottom ash, which we must handle, dispose, recycle or process. We recycle some of our fly ash and bottom ash production, principally by selling to the aggregate industry. This is referred to as beneficial use. In June 2010, the EPA proposed a rule to regulate CCBs under the Resource Conservation and Recovery Act (RCRA). The proposed rule provides two possible options for CCB regulation, both of which technically would allow for the continued beneficial use of CCBs, but we believe might actually curtail or impair beneficial use to the extent we are able to recycle it today. The first option would subject CCBs to regulation as special waste under Subtitle C of RCRA when disposed of in landfills or surface impoundments. The second option would regulate CCBs as non-hazardous solid waste under Subtitle D of RCRA. The EPA is expected to issue a final rule in 2012. 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.

Agreement with Regulators

We have entered into an agreement with the EPA and Department of Justice (DOJ) to resolve alleged violations of the federal Clean Air Act at JEC. The terms of the agreement require us to install additional equipment as well as perform environmental mitigation projects to further reduce air emissions. See "—EPA Lawsuit" below for additional information regarding the terms of the agreement.

Renewable Energy Standard

Kansas law mandates that our capacity consists of a certain amount of renewable sources. In years 2011 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. We met the 2011 requirement using our existing approximately 300 MW of qualifying wind generation facilities along with renewable energy credits. Beginning in late 2012, we will purchase under 20-year supply contracts the renewable energy produced from an additional approximately 370 MW of wind generation, which 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 power plants 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 interpretation of existing regulations, new regulations, legislation and the manner in which we operate the 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.

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 our approximately $600.0 million share of the costs associated with the $1.2 billion of environmental upgrades at La Cygne. We must file for a general review of our rates or an abbreviated rate review with the KCC in order to collect these costs. This 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.

Our estimated capital expenditures associated with environmental improvements for 2012-2014 appear in the following table. We prepare these estimates for planning purposes and revise them from time to time.

Year	La Cygne	Total
	(In Thousands)	
2012	$215,800	$435,100
2013	205,900	327,700
2014	122,300	229,700
Total	$544,000	$992,500

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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. In order to change our prices to recognize increased operating and maintenance costs, we must file a general rate review with the KCC.

Manufactured Gas Sites

We have been identified as being partially responsible for remediating a number of former manufactured gas sites located in Kansas. We and KDHE entered into a consent agreement governing all future work at these sites. Under terms of the consent agreement, we agreed to investigate and, if necessary, remediate these sites. Pursuant to an environmental indemnity agreement, ONEOK Inc. (ONEOK) assumed total liability for remediation of seven sites and we share liability for remediation with ONEOK for five sites. Our total liability for the five shared sites is capped at $3.8 million and terminates in November 2012.

EPA Lawsuit

In 2010, we settled a lawsuit filed by the DOJ on behalf of the EPA. We agreed to certain initial requirements as part of the settlement and also agreed to take further steps contingent on the outcome of the effectiveness of the initial requirements. As part of the initial requirements, we will install a selective catalytic reduction (SCR) on one of three JEC coal units by the end of 2014, which we estimate will cost approximately $240.0 million. Depending on the NOx emission reductions attained by the single SCR and attainable through the installation of other controls on the other two JEC coal units, we may have to install an SCR on another JEC unit by the end of 2016, if needed to meet plant-wide NOx reduction targets. We plan to recover the capital 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 be compliant with such laws and regulations.

Information Technology

The safeguarding of our information technology networks and systems is important to our business. There is risk associated with the unauthorized access or accidental release of electronic data, which may result in the misappropriation or corruption of our information or cause operational disruptions. We believe that we have appropriate levels of security measures in place to secure our information infrastructure from cybersecurity attacks or breaches and from accidental release of information, but notwithstanding such measures, this infrastructure may be vulnerable to damage or disruptions. See Item 1A, "Risk Factors," for additional information.

SEASONALITY

As a summer peaking utility, 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 15, 2012, we had 2,424 employees. In 2011, we negotiated a two year contract extension with Locals 304 and 1523 of the International Brotherhood of Electrical Workers that extends through June 30, 2013. The contract covered 1,322 employees as of February 15, 2012.

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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	50	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	53	Executive Vice President, Public Affairs and Consumer Services (since July 2007)	Westar Energy, Inc. Vice President, Regulatory and Public Affairs (March 2006 to June 2007)
Douglas R. Sterbenz	48	Executive Vice President and Chief Operating Officer (since July 2007)	Westar Energy, Inc. Executive Vice President, Generation and Marketing (March 2006 to June 2007)
Greg A. Greenwood	46	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	48	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	53	Vice President, Corporate Compliance and Internal Audit (since September 2007)	Westar Energy, Inc. Executive Director, Corporate Compliance and Internal Audit (September 2006 to September 2007)
Larry D. Irick	55	Vice President, General Counsel and Corporate Secretary (since February 2003)	
Lee Wages	63	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.

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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, 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.

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 these 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 frequently take positions adverse to us. The decision making process used in these proceedings may or may not be subject to statutory timelines, and in any event 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. 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.

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, economic conditions, regulatory requirements, social pressures and the responsiveness of customers' electricity demand to conservation measures and prices. Actual future 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.

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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.

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.

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 2012 through 2014 are approximately $2.5 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.

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.

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, 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 for these benefit plans. 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.

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;
- 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;

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- result in lower worldwide demand for coal, oil and natural gas, which may decrease fossil fuel prices and put downward pressure on electricity prices; and
- reduce the credit available to our energy trading counterparties and correspondingly reduce our energy trading activity or increase our exposure to counterparty default.

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.

Deliveries of fuel for our plants may be interrupted or slowed, which may adversely impact our consolidated financial results.

We purchase fuel, including coal, natural gas and uranium, from a number of suppliers. Disruption in the delivery of fuel or environmental regulations affecting any of our fuel suppliers could limit our ability to operate our facilities. In addition, the markets for coal, natural gas and uranium are subject to price fluctuations, availability restrictions and counterparty default. It is not possible to predict the cost or availability of these commodities. Such costs, if not recovered in our prices, could have a material adverse affect on our consolidated financial results.

We are subject to complex governmental regulation that could require us to incur additional expenses or subject us to penalties.

Our operations are subject to extensive regulation and require numerous permits, approvals and certificates from various governmental agencies. New laws or regulations, the revision or reinterpretation of existing laws or regulations, or penalties imposed for non-compliance with existing laws or regulations may require us to incur additional expenses, which could have a material affect on our consolidated financial results.

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.

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 discharges into the air, air quality, discharges of effluents into water, 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 often become more restrictive, requires us to commit significant capital and operating resources toward permitting, emission fees, environmental monitoring, installation and operation of air 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.

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Security breaches, 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. Despite security measures and business continuity plans, 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 and energy marketing and trading functions; could expose us or our customers or 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.

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.

The effect of pending and/or proposed environmental laws, such as CSAPR and MATS for power plants, could have a material effect on our operations and consolidated financial results.

Laws and regulations governing the emissions of air pollutants from power plants are becoming increasingly stringent. For example, in July 2011, the EPA finalized CSAPR, which, if upheld, would require us and other power plants in 28 states including Kansas, Oklahoma and Missouri, to reduce NOx and SO_2 emissions. In December 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued its ruling to stay CSAPR pending judicial review. The court is scheduled to hear the cases in April 2012. Under this timeframe, the court could issue its decision by summer or early fall 2012. If CSAPR (or material aspects of it) survive legal and Congressional challenge, we expect that we could have to modify the way in which we use our power plants, purchase power or purchase emission allowances. If we are unable or choose not to reduce our emissions, there are no assurances there will be sufficient allowances or power from other utilities available in the market or, if available, they may be purchased only at a prohibitive cost. If we do not reduce our emissions or cannot buy sufficient allowances or other power, we may need to shut down certain generating units, which could have a material effect on our operations and consolidated financial results. Finally, if we do choose to reduce our emissions, given CSAPR's tight timelines, we may not be able to reduce emissions by the stated deadlines stated in CSAPR, which could result in fines, penalties or other sanctions. In addition, the EPA finalized MATS for power plants in December 2011. If that rule survives legal and Congressional challenges, it will require us to install costly pollution control technology or, if that is not possible or economically feasible, to shut down certain generating units, each of which could have a material effect on our operations and/or consolidated financial results. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Current Trends - Environmental Regulation - Air Emissions" for additional information.

We may be subject to legislative and regulatory responses to concerns about climate change, which could require us to incur substantial costs.

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 may in the future be introduced in Congress to regulate the emission of GHGs and numerous states have adopted programs to stabilize or reduce GHG emissions.

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Additionally, the EPA regulates GHGs under the Clean Air Act. Under EPA regulations finalized in May 2010, the EPA is regulating GHG emissions from certain stationary sources, such as power plants, in January 2011. 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. The EPA is expected to issue a proposed rule in 2012 that may reduce the 75,000 ton threshold. Sources that already have a Title V permit would have GHG provisions added to their permit upon renewal. Additionally, PSD 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.

Furthermore, in December 2010, the EPA announced that it would be proposing GHG NSPS rules for EGUs and refineries. The rules will apply to new and existing facilities. The EPA had announced that it would propose the new rules by September 30, 2011, but has postponed the proposed rules for new and modified EGUs. It is unclear when the EPA will propose new rules for existing EGUs and how stringent they may be, but the rules are expected. Because these regulations have yet to be proposed or finalized, we cannot predict the impact they may have on our operations or consolidated financial results, but it could be material.

Our cost of compliance with future federal regulations relating to the disposal of CCBs could require us to incur substantial costs.

In the course of operations, many of our facilities generate CCBs, including fly ash and bottom ash, which we must handle, dispose of, recycle or process. In June 2010, the EPA proposed a rule to regulate CCBs under RCRA. The proposed rule provides two possible options for CCB regulation, one of which would subject CCBs to increased regulation as special waste under Subtitle C of RCRA. The EPA is expected to issue a final rule in 2012. While the impact and cost associated with the potential future regulation of CCBs cannot be established until such regulations are finalized, such regulations could have a material impact on our operations and/or consolidated financial results.

Our risk management policies cannot eliminate price volatility and counterparty credit risks associated with our energy marketing activities.

We engage in energy marketing transactions with the goal of managing our commodity price risk, enhancing system reliability and increasing profits. We operate in an active wholesale market that exposes us to price volatility for electricity, fuel and other commodities. The prices we use to value these transactions reflect our best estimates of the fair value of these contracts. Results actually achieved from these activities could vary materially from intended results and could cause significant earnings variability. In addition, we are exposed to credit risks of our counterparties and the risk that one or more counterparties may fail to perform their obligations to make payments or deliveries. Defaults by suppliers or other counterparties may adversely affect our consolidated financial results.

We attempt to manage our exposure to price volatility and counterparty credit risk through application of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities.

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:

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- the risks associated with storing, handling and disposing of radioactive materials and the current lack of a long-term 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.

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The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements enacted by the NRC could necessitate substantial capital expenditures at Wolf Creek. In addition, the Institute of Nuclear Power Operations (INPO) reviews Wolf Creek operations and facilities. Compliance with INPO recommendations could result in substantial capital expenditures or a substantial increase in operating expenses at Wolf Creek being passed through to KGE.

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 shut down 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.

Events could occur that would change the accounting principles for regulated utilities currently applicable to our business, which would have an adverse impact on our consolidated financial results.

We currently apply accounting principles that are unique to regulated entities. As of December 31, 2011, we had recorded regulatory assets of $1.0 billion and regulatory liabilities of $271.4 million. In the event we determined that we could no longer apply these principles, either as: (i) a result of the establishment of retail competition in our service territory; (ii) a change in the regulatory approach for setting our prices from cost-based ratemaking to another form of ratemaking; (iii) a result of other regulatory actions that restrict cost recovery to a level insufficient to recover costs; or (iv) a change from current generally accepted accounting principles (GAAP) to another set of standards that does not recognize regulatory assets and/or liabilities, then we may be required to record a charge against income in an amount up to the remaining unamortized regulatory assets. Such an action would materially reduce our shareholders' equity. We review these criteria to ensure that the continuing application of these principles is appropriate each reporting period. Based upon our most current evaluation of the various factors that are expected to impact future cost recovery, we believe that our regulatory assets are probable of recovery.

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. Although we maintain our power plants and equipment, they are still 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
Abilene Energy Center:	Abilene, Kansas							
Combustion Turbine		1		1973	Gas	68	—	68
Central Plains Wind Farm	Wichita County, Kansas		(a)	2009	Wind	3	—	3
Emporia Energy Center:	Emporia, Kansas							
Combustion Turbines		1		2008	Gas	45	—	45
		2		2008	Gas	46	—	46
		3		2008	Gas	45	—	45
		4		2008	Gas	46	—	46
		5		2008	Gas	159	—	159
		6		2009	Gas	159	—	159
		7		2009	Gas	160	—	160
Flat Ridge Wind Farm	Barber County, Kansas		(a)	2009	Wind	2	—	2
Gordon Evans Energy Center:	Colwich, Kansas							
Steam Turbines		1		1961	Gas-Oil	—	155	155
		2		1967	Gas-Oil	—	372	372
Combustion Turbines		1		2000	Gas	73	—	73
		2		2000	Gas	71	—	71
		3		2001	Gas	150	—	150
Hutchinson Energy Center:	Hutchinson, Kansas							
Steam Turbine		4		1965	Gas-Oil	167	—	167
Combustion Turbines		1		1974	Gas	55	—	55
		2		1974	Gas	56	—	56
		3		1974	Gas	56	—	56
		4		1975	Diesel	62	—	62
Jeffrey Energy Center (92%):	St. Marys, Kansas							
Steam Turbines		1	(b)	1978	Coal	521	145	666
		2	(b)	1980	Coal	522	145	667
		3	(b)	1983	Coal	526	146	672
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	371	—	371
Murray Gill Energy Center:	Wichita, Kansas							
Steam Turbines		1		1952	Gas	—	40	40
		2		1954	Gas-Oil	—	56	56
		3		1956	Gas-Oil	—	102	102
		4		1959	Gas-Oil	—	95	95
Neosho Energy Center:	Parsons, Kansas							
Steam Turbine		3		1954	Gas-Oil	—	62	62
Spring Creek Energy Center:	Edmond, Oklahoma							
Combustion Turbines		1	(d)	2001	Gas	72	—	72

		2	(d)	2001	Gas	70	—	70
		3	(d)	2001	Gas	68	—	68
		4	(d)	2001	Gas	69	—	69
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	73	—	73
		8		1962	Coal	132	—	132
Wolf Creek Generating Station (47%):	Burlington, Kansas							
Nuclear		1	(b)	1985	Uranium	—	547	547
Total						4,208	2,576	6,784

(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.

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We own and have in service approximately 6,300 miles of transmission lines, approximately 23,800 miles of overhead distribution lines and approximately 4,400 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 other 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.

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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 15, 2012, Westar Energy had 21,231 common shareholders of record. For information regarding quarterly common stock price ranges for 2011 and 2010, see Note 20 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, 2006, and ended on December 31, 2011, 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 2006	Dec 2007	Dec 2008	Dec 2009	Dec 2010	Dec 2011
Westar Energy Inc.	$100	$104	$87	$98	$120	$144
S&P© 500	$100	$106	$66	$84	$97	$99
S&P© Electric Utilities	$100	$123	$91	$94	$98	$118

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DIVIDENDS

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

Quarterly dividends on preferred and 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 2011, Westar Energy's board of directors declared four quarterly dividends of $0.32 per share, reflecting an annual dividend of $1.28 per share, compared to four quarterly dividends of $0.31 per share in 2010, reflecting an annual dividend of $1.24 per share. On February 23, 2012, Westar Energy's board of directors declared a quarterly dividend of $0.33 per share payable to shareholders on April 2, 2012. The indicated annual dividend rate is $1.32 per share.

Westar Energy's articles of incorporation restrict the payment of dividends or other distributions on its common stock while any preferred shares remain outstanding unless it meets certain capitalization ratios and other conditions. Westar Energy was not limited by any such restrictions during 2011. Further information on these restrictions is included in Note 16 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock." Westar Energy does not expect these restrictions to have an impact on its ability to pay dividends on its common stock.

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ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In Thousands)				
Income Statement Data:					
Total revenues	$2,170,991	$2,056,171	$1,858,231	$1,838,996	$1,726,834
Income from continuing operations	236,180	208,624	141,330	178,140	168,354
Net income attributable to common stock	229,269	202,926	174,105	177,170	167,384

	As of December 31,				
	2011	2010	2009	2008	2007
	(In Thousands)				
Balance Sheet Data:					
Total assets	$8,682,851	$8,079,638	$7,525,483	$7,443,259	$6,395,430
Long-term obligations (a)	2,818,030	2,808,560	2,610,315	2,465,968	2,022,493

	Year Ended December 31,				
	2011	2010	2009	2008	2007
Common Stock Data:					
Basic earnings per share available for common stock from continuing operations (b)	$1.95	$1.81	$1.28	$1.69	$1.83
Basic earnings per share available for common stock (b)	$1.95	$1.81	$1.58	$1.69	$1.83
Dividends declared per share	$1.28	$1.24	$1.20	$1.16	$1.08
Book value per share	$22.03	$21.25	$20.59	$20.18	$19.14
Average equivalent common shares outstanding (in thousands) (c) (d) (e) (f)	116,891	111,629	109,648	103,958	90,676

(a) Includes long-term debt, net, current maturities of long-term debt, capital leases and, for 2011 and 2010, long-term debt of VIEs, net and current maturities of long-term debt of VIEs. See Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," for additional information regarding VIEs.

(b) Earnings per share (EPS) amounts previously reported for 2008 and 2007 were adjusted to reflect the use of the two-class method. See Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies—Earnings Per Share," for additional information regarding the two-class method.

(c) In 2007, Westar Energy issued and sold approximately 8.1 million shares of common stock realizing proceeds of $195.4 million.

(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.

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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 688,000 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. In addition, we engage in energy marketing and purchase and sell electricity in areas outside of our retail service territory.

Summary of Significant Items

Following is a summary of our net income and basic EPS for the years ended December 31, 2011 and 2010.

	Year Ended December 31,		
	2011	2010	Change
	(Dollars In Thousands, Except Per Share Amounts)		
Net income attributable to common stock	$229,269	$202,926	$26,343
Earnings per common share, basic	1.95	1.81	0.14

The increases shown in the above table were due principally to the reversal of $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 a $7.2 million gain on the sale of a non-utility investment. See the discussion under "—Operating Results" below for additional factors that affected our net income attributable to common stock for the year ended December 31, 2011.

Following is a summary of significant items relating to our operations for the year ended December 31, 2011:

- We believe improving economic conditions are why some of our industrial customers experienced increased production during 2011, which resulted in more electricity sales to them. As a result, industrial electricity sales increased 2% in 2011. In addition, as measured by cooling degree days, the weather in 2011 was about 7% warmer than in 2010 and 30% warmer than the 20-year average. Warmer weather typically results in more electricity sales to residential and, to a lesser extent, commercial and industrial customers. However, we believe energy efficiency measures, energy conservation and a lack of retail customer growth partially offset some of the impact of the aforementioned factors as total retail electricity sales increased just 1% in 2011. Our retail customer count for 2011 was essentially flat to that of 2010;

- We made capital expenditures of $697.5 million during 2011. See "Liquidity and Capital Resources" below for additional information; and

- Westar Energy delivered approximately 12.7 million shares of common stock for proceeds of approximately $289.2 million as settlement of forward sale transactions entered into in 2010. See Note 16 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock," for additional information.

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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 are making environmental upgrades to our coal-fired power plants, developing renewable generation, and building and upgrading transmission facilities, in addition to developing systems and programs to help customers use energy more efficiently. Following is a summary of recent progress we have made on significant elements of our strategy.

- During 2011, we invested $220.0 million at our power plants to reduce regulated emissions.
- We have entered into two separate agreements with third parties to purchase under 20-year supply contracts renewable energy produced from approximately 370 MW of wind generation beginning in late 2012. These contracts, along with our prior development of wind generation, will provide for approximately 670 MW of total wind generation, which satisfies present statutory requirements.
- In late 2011, we began installing advanced metering infrastructure for SmartStar Lawrence. The project will enable customers to better monitor their energy use. We qualified to receive a matching grant of approximately $19.0 million from the DOE. We expect to complete equipment installation in early 2012 and anticipate total project costs of approximately $39.3 million.

Our plans and expectations for 2012 and beyond are as follows.

- We plan to invest approximately $1.0 billion at our power plants over the next three years to reduce regulated emissions.
- We expect to complete construction of a 50-mile 345 kV transmission line in south central Kansas in mid 2012.
- Prairie Wind Transmission, LLC, a joint venture company of which we own 50%, has under development 110 miles of transmission facilities running from near Wichita, Kansas, southwest to a location near Medicine Lodge, Kansas, and then south to the Oklahoma border. The project is scheduled for completion in 2014.
- In addition to the transmission lines described above, subject to regulatory approvals, we intend to make further investments to strengthen and improve Kansas' electrical transmission network.

Current Trends

Environmental Regulation

Environmental laws and regulations affecting power plants, which relate primarily to discharges into the air, air quality, discharges of effluents into water, 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 that all such costs will be reflected in the prices we are allowed to charge customers, we cannot assure that all such costs 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.

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Air Emissions

The operation of power plants results in emissions of PM, mercury and other air toxics. In December 2011, the EPA finalized MATS for power plants, which replaces the prior federal CAMR and requires significant reductions in emissions of mercury and other air toxics. Companies impacted by the new standards will have up to four years, and in certain limited circumstances up to five years, to comply. We are currently evaluating the new standards and cannot at this time determine the impact they may have on our operations and consolidated financial results, but we believe the cost of compliance could be material.

In July 2011, the EPA finalized CSAPR which requires 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 1, 2012, with further reductions required beginning January 1, 2014. The EPA issued federal implementation plans for each state covered by CSAPR, but would allow these states to submit their own implementation plans starting as early as 2013.

In October 2011, the EPA issued a proposed amendment to CSAPR that, according to the EPA, would slightly ease the new emission standards and defer the effective date of certain penalty provisions from January 1, 2012, to January 1, 2014.

In December 2011, the EPA published a final supplemental rule to CSAPR requiring five states to make summertime reductions in NOx emissions under an ozone-season control program implemented under CSAPR. Reductions in ozone-season NOx under this rule begin May 1, 2012. Although Kansas was included in the original proposed rule, the final supplemental rule instead calls for the EPA to revisit Kansas' status under this supplemental rule once Kansas submits an ozone state implementation plan, which must occur within 12 to 18 months from the date the EPA issues a state implementation call to Kansas. The EPA has not yet issued such a call.

In October 2011, we filed legal challenges to CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the court issued its ruling to stay CSAPR, including the final supplemental rule, pending judicial review, which delays CSAPR's implementation date beyond January 1, 2012. The court is scheduled to hear the cases starting in April 2012. Under this timeframe, the court could issue its decision by summer or early fall 2012. As the outcome of the judicial review and any other possible legal or Congressional challenges are uncertain, we are unable to determine what impact CSAPR may ultimately have on our operations and consolidated financial results, but it could be material. See "Item 1A. Risk Factors" for additional information.

Greenhouse Gases

Under EPA regulations finalized in May 2010, 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: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications, which is referred to as PSD. Obligations relating to Title V permits include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors), are required to implement BACT. 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. The EPA is expected to issue a proposed rule in 2012 that may reduce the 75,000 and 100,000 ton thresholds noted above. 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.

In December 2010, the EPA announced that it would be proposing GHG NSPS rules for EGUs and refineries. The rules will apply to new and existing facilities. The EPA had announced that it would propose the new rules by September 30, 2011, but has postponed the proposed rules for new and modified EGUs. It is unclear when the EPA will propose new rules for existing EGUs and how stringent they may be, but the rules are expected. Because these regulations have yet to be proposed or finalized, we cannot predict the impact they may have on our operations or consolidated financial results, but it could be material.

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Regulation of Coal Combustion Byproducts

In the course of operating our coal generation plants, we produce CCBs, including fly ash and bottom ash, which we must handle, dispose, recycle or process. We recycle some of our fly ash and bottom ash production, principally by selling to the aggregate industry. This is referred to as beneficial use. In June 2010, the EPA proposed a rule to regulate CCBs under RCRA. The proposed rule provides two possible options for CCB regulation, both of which technically would allow for the continued beneficial use of CCBs, but we believe might actually curtail or impair beneficial use to the extent we are able to recycle it today. The first option would subject CCBs to regulation as special waste under Subtitle C of RCRA when disposed of in landfills or surface impoundments. The second option would regulate CCBs as non-hazardous solid waste under Subtitle D of RCRA. The EPA is expected to issue a final rule in 2012. 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 six criteria emissions considered harmful to public health and the environment, including PM, NOx, CO and SO_2, which result from coal combustion. Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS. NAAQS must be reviewed by the EPA at five-year intervals. In 2009, KDHE proposed to designate portions of the Kansas City area nonattainment for the 8-hour ozone standard, which has the potential to impact our operations.

In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. We 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.

PM, principally ash, is a byproduct of coal combustion. The EPA is currently reviewing the PM NAAQS. We cannot at this time predict the impact of this review and any possible new standards on our operations or consolidated financial results, but it could be material.

The EPA had been in the process of revising the NAAQS for ozone. However, in September 2011, the President of the United States ordered the EPA to withdraw its proposal. Work is currently underway to support the EPA's planned reconsideration of the standards in 2013.

Wastewater Effluent

Some water used in our operations is discharged as wastewater effluent. This wastewater may contain substances deemed to be pollutants. The EPA plans to propose revisions to the rules governing such wastewater effluent from coal-fired power plants by July 2012 with final action on the proposed rules expected to occur by January 2014. Although we cannot at this time determine the impact of any new regulations, more stringent regulations could have a material impact on our operations and consolidated financial results.

In April 2011, the EPA issued a proposed rule that would set stricter technology standards for cooling water intake structures at power plants. We are currently evaluating the proposal. The EPA is expected to finalize the proposal in 2012; however, because the rule has yet to be finalized, we cannot predict the impact it may have on our operations or consolidated financial results, but it could be material.

Renewable Energy Standard

Kansas law mandates that our capacity consists of a certain amount of renewable sources. In years 2011 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. We met the 2011 requirement using our existing approximately 300 MW of qualifying wind generation facilities along with renewable energy credits. Beginning in late 2012, we will purchase under 20-year supply contracts the renewable energy produced from an additional approximately 370 MW of wind generation, which 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.

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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 March 2011, the NRC established a task force to conduct a review of U.S. nuclear power plant safety in the aftermath of an earthquake and tsunami that eventually resulted in station blackout and a very serious event at Japan's Fukushima Daiichi nuclear power plant. The task force has provided a report and proposed improvements to the NRC which has the responsibility for making decisions regarding the task force recommendations. The timing and effects of any NRC action with respect to regulations, safety initiatives and licensing process cannot be determined at this time.

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,		
	2011	2010	2009
	(In Thousands)		
Borrowed funds	$5,589	$4,295	$4,857
Equity funds	5,550	3,104	5,031
Total	$11,139	$7,399	$9,888
Average AFUDC Rates	3.6 %	2.6 %	4.2 %

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 persist.

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 due principally to the effects of the economic downturn. 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.

2012 Outlook

In 2012, 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, and expect a decision from the KCC regarding our general rate review as discussed under "Other Information" below. As we have no way of predicting the weather, we assume for planning purposes normal weather in line with its historical average, which means for 2012 that we anticipate lower residential and commercial electricity sales than in 2011. We expect a slight increase in industrial electricity sales under the assumption that economic conditions will continue to improve and because industrial customers generally are less affected by weather. We expect retail customer growth in 2012 to be below the long-term historical average.

In addition, we anticipate higher operating and maintenance expense, 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 $79.7 million to our pension and post-retirement benefit plans and Wolf Creek's pension plan in 2012. To help fund our increased capital spending as provided under "—Future Cash Requirements" below, we plan to issue long-term debt in addition to utilizing commercial paper and revolving credit facilities. Moreover, we expect a decision from the U.S. Court of Appeals for the District of Columbia Circuit regarding CSAPR, which is discussed under "Current Trends" above.

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 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, 2011, we had recorded regulatory assets currently subject to recovery in future prices of approximately $1.0 billion and regulatory liabilities of $271.4 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.

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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	$71,826	$6,043
	0.5% increase	(67,148)	(5,920)
Salary scale	0.5% decrease	(18,139)	(3,291)
	0.5% increase	18,480	3,388
Rate of return on plan assets	0.5% decrease	—	2,805
	0.5% increase	—	(2,784)

(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	$8,660	$386
	0.5% increase	(8,216)	(402)
Rate of return on plan assets	0.5% decrease	—	445
	0.5% increase	—	(443)
Annual medical trend	1.0% decrease	(1,261)	(150)
	1.0% increase	1,361	161

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

Revenue Recognition

Electricity Sales

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

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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 $54.0 million as of December 31, 2011, and $53.8 million as of December 31, 2010.

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 as current energy marketing assets and 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.

The following table shows the net fair value of energy marketing contracts outstanding as of December 31, 2011.

	Fair Value of Contracts (In Thousands)
Net fair value of contracts outstanding as of December 31, 2010 (a)	$12,797
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	(2,867)
Changes in fair value of contracts outstanding at the beginning and end of the period	(1,591)
Fair value of new contracts entered into during the period	1,039
Net fair value of contracts outstanding as of December 31, 2011 (b)	$9,378

(a) Approximately $7.8 million of the fair value of energy marketing contracts was recognized as a regulatory liability.
(b) Approximately $0.4 million and $6.2 million of the fair value of energy marketing contracts were recognized as a regulatory asset and regulatory liability, respectively.

The sources of the fair values of the financial instruments related to these contracts and the maturity periods of the contracts as of December 31, 2011, are summarized in the following table

	Fair Value of Contracts at End of Period				
Sources of Fair Value	Total Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity Over 5 Years
	(Dollars In Thousands)				
Prices provided by other external sources (swaps and forwards)	$9,525	$1,906	$7,619	$—	$—
Prices based on option pricing models (options and other) (a)	(147)	(79)	(68)	—	—
Total fair value of contracts outstanding	$9,378	$1,827	$7,551	$—	$—

(a) Options are priced using a series of techniques, such as the Black option pricing model.

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Normal Purchases and Normal Sales Exception

Determining whether a contract qualifies for the normal purchases and normal sales exception requires that we exercise judgment on whether the contract will physically deliver and requires that we ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and price is not tied to an unrelated underlying derivative.

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, 2011 and 2010, we have recorded AROs of $142.5 million and $126.0 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, 2011 and 2010, we had $82.3 million and $70.3 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability.

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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 Note 13 and 15 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies" and "Legal Proceedings," for more detailed 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. This category also includes changes in valuations of contracts for the sale of such electricity that have yet to settle. 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, customer conservation efforts, 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.

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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) Transmission: 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.

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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, 2011 and 2010.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars In Thousands)			
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	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
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.

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

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	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 No. 6 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 from continuing operations before income taxes.

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2010 Compared to 2009

Below we discuss our operating results for the year ended December 31, 2010, compared to the results for the year ended December 31, 2009. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$661,177	$576,896	$84,281	14.6
Commercial	572,062	529,847	42,215	8.0
Industrial	318,249	291,754	26,495	9.1
Other retail	(12,703)	(18,516)	5,813	31.4
Total Retail Revenues	1,538,785	1,379,981	158,804	11.5
Wholesale	334,669	308,269	26,400	8.6
Transmission (a)	144,513	132,450	12,063	9.1
Other	38,204	37,531	673	1.8
Total Revenues	2,056,171	1,858,231	197,940	10.7
OPERATING EXPENSES:				
Fuel and purchased power	583,361	534,864	48,497	9.1
Operating and maintenance	520,409	516,930	3,479	0.7
Depreciation and amortization	271,937	251,534	20,403	8.1
Selling, general and administrative	207,607	199,961	7,646	3.8
Total Operating Expenses	1,583,314	1,503,289	80,025	5.3
INCOME FROM OPERATIONS	472,857	354,942	117,915	33.2
OTHER INCOME (EXPENSE):				
Investment earnings (losses)	7,026	12,658	(5,632)	(44.5)
Other income	5,369	7,128	(1,759)	(24.7)
Other expense	(16,655)	(17,188)	533	3.1
Total Other Income	(4,260)	2,598	(6,858)	(264.0)
Interest expense	174,941	157,360	17,581	11.2
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	293,656	200,180	93,476	46.7
Income tax expense	85,032	58,850	26,182	44.5
INCOME FROM CONTINUING OPERATIONS	208,624	141,330	67,294	47.6
Results of discontinued operations, net of tax	—	33,745	(33,745)	(100.0)
NET INCOME	208,624	175,075	33,549	19.2
Less: Net income attributable to noncontrolling interests	4,728	—	4,728	(b)
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY	203,896	175,075	28,821	16.5
Preferred dividends	970	970	—	—
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$202,926	$174,105	$28,821	16.6
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY:				
Earnings available from continuing operations	$1.81	$1.28	$0.53	41.4
Discontinued operations, net of tax	—	0.30	(0.30)	(100.0)

Earnings per common share	$1.81	$1.58	$0.23	14.6

(a) Transmission: Reflects revenue from an SPP network transmission tariff. In 2010 and 2009, our SPP network transmission costs were $116.4 million and $105.4 million, respectively. These amounts, less administration costs of $14.4 million and $11.2 million, respectively, were returned to us as revenue.

(b) Cannot divide by zero.

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Gross Margin

The following table summarizes our gross margin for the years ended December 31, 2010 and 2009.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars In Thousands)			
REVENUES:				
Residential	$661,177	$576,896	$84,281	14.6
Commercial	572,062	529,847	42,215	8.0
Industrial	318,249	291,754	26,495	9.1
Other retail	(12,703)	(18,516)	5,813	31.4
Total Retail Revenues	1,538,785	1,379,981	158,804	11.5
Wholesale	334,669	308,269	26,400	8.6
Transmission	144,513	132,450	12,063	9.1
Other	38,204	37,531	673	1.8
Total Revenues	2,056,171	1,858,231	197,940	10.7
Less: Fuel and purchased power expense	583,361	534,864	48,497	9.1
SPP network transmission costs	116,449	105,401	11,048	10.5
Gross Margin	$1,356,361	$1,217,966	$138,395	11.4

The following table reflects changes in electricity sales for the years ended December 31, 2010 and 2009. 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,			
	2010	2009	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,957	6,404	553	8.6
Commercial	7,519	7,235	284	3.9
Industrial	5,468	5,145	323	6.3
Other retail	89	88	1	1.1
Total Retail	20,033	18,872	1,161	6.2
Wholesale	8,712	8,788	(76)	(0.9)
Total	28,745	27,660	1,085	3.9

Gross margin increased due principally to an increase in total retail revenues. Of the $158.8 million increase in total retail revenues, 53% was attributable to higher electricity sales and 47% was due to higher prices as discussed in Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation." Retail electricity sales increased due primarily to the effects of warmer weather, which particularly impacted residential electricity sales, and for reasons we believe to be principally related to improved economic conditions. As measured by cooling degree days, the weather during 2010 was 47% warmer than 2009 and 25% warmer than the 20-year average. While weather also affects commercial and industrial customers, those electricity sales typically are not as sensitive to weather as residential electricity sales. We believe improving economic conditions are why some of our commercial and industrial customers experienced increased orders and production in 2010, which lead to increased electricity sales to them. Economic conditions generally have not recovered to levels experienced prior to the economic downturn.

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The following table reconciles income from operations with gross margin for the years ended December 31, 2010 and 2009.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars In Thousands)			
Gross margin	$1,356,361	$1,217,966	$138,395	11.4
Add: SPP network transmission costs	116,449	105,401	11,048	10.5
Less: Operating and maintenance expense	520,409	516,930	3,479	0.7
Depreciation and amortization expense	271,937	251,534	20,403	8.1
Selling, general and administrative expense	207,607	199,961	7,646	3.8
Income from operations	$472,857	$354,942	$117,915	33.2

Operating Expenses and Other Income and Expense Items

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Operating and maintenance expense	$520,409	$516,930	$3,479	0.7

Operating and maintenance expense increased due primarily to higher SPP network transmission costs of $11.0 million, which were offset by higher SPP network transmission revenues of $7.9 million, higher power plant maintenance costs of $7.6 million and higher maintenance costs of $5.6 million for our electrical distribution system. The higher power plant maintenance costs were due primarily to higher costs at Wolf Creek and our wind generation facilities while the increase in maintenance costs for our electrical distribution system was due principally to additional tree trimming and other line clearance activities in 2010. Offsetting these increases was a $20.4 million reduction resulting from the consolidation of VIEs as discussed in Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," and a $5.0 million reduction in our liability for environmental remediation costs associated with assets we divested many years ago.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Depreciation and amortization expense	$271,937	$251,534	$20,403	8.1

Depreciation and amortization expense increased primarily to reflect the addition of wind generation facilities, new generating plant, air quality controls at our power plants and other plant additions. We also recorded additional depreciation expense of $6.1 million as a result of consolidating VIEs as discussed in Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities."

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Selling, general and administrative expense	$207,607	$199,961	$7,646	3.8

A significant amount of our non-union, non-executive employee compensation is at-risk to employees and, therefore, payable only in the event we meet pre-established operating and financial objectives. Likewise, under our executive long-term incentive and share award plan, shares are issued only when certain service conditions are met and/or we meet pre-established financial objectives. In 2010 we adjusted these compensation plans to better align compensation with our financial performance. Selling, general and administrative expense increased due principally to higher compensation expense of $12.9 million that was primarily the result of the aforementioned plan adjustments and our improved financial performance. This increase was partially offset by our having recorded a $4.0 million expense in 2009 related to the settlement of the EPA lawsuit discussed in Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies."

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	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Investment earnings	$7,026	$12,658	$(5,632)	(44.5)

Investment earnings decreased due principally to our having recorded lower gains on investments held in a trust to fund retirement benefits. We recorded gains on these investments of $4.8 million in 2010 compared to gains of $8.4 million recorded in 2009.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Interest expense	$174,941	$157,360	$17,581	11.2

Interest expense increased due primarily to our having recorded additional interest expense of $12.2 million as a result of consolidating VIEs as discussed in Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," and interest on additional debt issued in June 2009 to fund capital investments.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Income tax expense	$85,032	$58,850	$26,182	44.5

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

Financial Condition

A number of factors affected amounts recorded on our balance sheet as of December 31, 2011, compared to December 31, 2010.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Fuel inventory and supplies	$229,118	$206,867	$22,251	10.8

Fuel inventory and supplies increased due principally to a $15.5 million increase in storeroom inventory largely resulting from additional materials and replacement parts for new air quality controls. Coal inventory increased $8.3 million due to a 15% increase in the delivered cost of coal resulting primarily from a new long-term transportation contract at La Cygne.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Property, plant and equipment, net	$6,411,922	$5,964,439	$447,483	7.5

Property, plant and equipment, net increased due to additions of $499.4 million at our power plants, including the installation of air quality controls, distribution and transmission projects.

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	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Regulatory assets	$1,046,090	$861,065	$185,025	21.5
Regulatory liabilities	271,387	267,074	4,313	1.6
Net regulatory assets	$774,703	$593,991	$180,712	30.4

Total regulatory assets increased due primarily to the following reasons:

- a $129.9 million increase in deferred employee benefits;
- a $41.5 million decrease in the fair value of treasury yield hedges;
- a $15.4 million increase in net amounts deferred for the Wolf Creek outage; and
- a $19.6 million increase in deferred fuel costs; however,
- partially offsetting increases was a $9.0 million decrease in previously deferred storm costs.

Regulatory liabilities increased due principally to a $12.0 million increase in removal costs and an $8.8 million increase in our refund obligation related to the RECA. Offsetting increases was the $9.9 million revision in our estimated costs to decommission Wolf Creek.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Short-term debt	$286,300	$226,700	$59,600	26.3

Short-term debt increased due principally to increased borrowings under Westar Energy's revolving credit facility. We used borrowings under the revolving credit facility to fund our capital and on-going operating needs on an interim basis.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Other current liabilities	$148,347	$171,222	$(22,875)	(13.4)

Other current liabilities decreased due principally to the following reasons:

- our having reached settlement agreements with former officers as discussed in Note 15 of the Notes to Consolidated Financial Statements, "Legal Proceedings"; and
- our having accrued $7.6 million less in 2011 for non-union, non-executive, at-risk employee compensation than in 2010; however,
- partially offsetting decreases was the change in the fair value of treasury yield hedges.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Net deferred income tax liabilities	$1,110,463	$1,102,625	$7,838	0.7

Net deferred income taxes increased due primarily to recording $168.5 million of tax benefits resulting from the use of bonus and accelerated depreciation methods. However, the following partially offset this increase:

- the tax effect of a deferred net operating loss for the current year of $86.7 million; and
- a net state tax credit carryforward benefit of $70.2 million including the reversal of a valuation allowance of $51.9 million. The valuation allowance relates to the state tax credit carryforwards that are now more likely than not to be realized due to a state law change which extends the state tax credit carryforward period from 10 to 16 years.

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	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Unamortized investment tax credits	$164,175	$101,345	$62,830	62.0

Unamortized investment tax credits increased due primarily to reversing $51.9 million of valuation allowances on state investment tax credits as discussed in the prior paragraph.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Accrued employee benefits	$592,617	$483,769	$108,848	22.5

Accrued employee benefits increased due primarily to a higher projected benefit obligation for our and Wolf Creek's pension plans. We recognize as a regulatory asset or regulatory liability the difference between the fair value of pension and post-retirement benefit plan assets and the liabilities for pension and post-retirement benefit plans. See Notes 11 and 12 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans" and "Wolf Creek Employee Benefit Plans," respectively, for additional information.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Other long-term liabilities	$74,138	$66,888	$7,250	10.8

Other long-term liabilities increased due primarily to a power supply agreement classified as a capital lease during the year offset by legal settlements with former executive officers. See Notes 15 and 18 of the Notes to Consolidated Financial Statements, "Legal Proceedings" and "Leases," respectively, for further information.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(Dollars in Thousands)			
Common stock	$628,492	$560,640	$67,852	12.1
Paid-in capital	1,639,503	1,398,580	240,923	17.2
Total	$2,267,995	$1,959,220	$308,775	15.8

Common stock and paid-in capital increased due to the issuance of 13.6 million shares of common stock. See Note 16 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock," for additional information.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Available sources of funds to operate our business include internally generated cash, Westar Energy's revolving credit facilities and commercial paper program, 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, borrowings under the revolving credit facilities and commercial paper issuances. To meet the cash requirements for our capital investments, we expect to use internally generated cash, temporary borrowings under the revolving credit facilities and commercial paper issuances, as well as 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, when such balances are of sufficient size and it makes economic sense to do so, and for working capital and general corporate purposes. The aforementioned sources and uses of cash are similar to our historical activities. For additional information on our future cash requirements, see "-Future Cash Requirements" below.

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During 2012, we plan to increase our capital spending and expect to continue contributing 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, 2011 and 2010, our capital structure, excluding short-term debt, was as follows:

	2011	2010
Common equity	50%	46%
Preferred stock	<1%	<1%
Noncontrolling interests	<1%	<1%
Long-term debt, including VIEs	50%	54%

Short-Term Borrowings

On December 9, 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 repay borrowings under Westar Energy's revolving credit facilities, for capital expenditures and/or for other general corporate purposes. As of February 15, 2012, Westar Energy had issued $414.7 million of commercial paper.

Westar Energy has two revolving credit facilities in the amounts of $730.0 million and $270.0 million, which terminate on September 29, 2016, and February 18, 2015, respectively. As long as there is no default under the facilities, each may be extended up to an additional two years 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. As of February 15, 2012, no amounts were borrowed and $13.9 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. In addition, total combined borrowings under the revolving credit facilities and the commercial paper program may not exceed $1.0 billion at any given time.

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, 2011, our ratio was 51%. See Note 8 of the Notes to Consolidated Financial Statements, "Short-Term Debt," for additional information regarding our short-term borrowings.

Debt Financing

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, 2011, approximately $1.0 billion 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, 2011, based on an assumed interest rate of 4.125%, approximately $436.2 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. We use these ratios solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2011.

As of December 31, 2011, we had $121.9 million of variable rate, tax-exempt bonds. Interest rates payable under these bonds had historically been set by auctions, which occur every 35 days. However, auctions for these bonds have failed over the past few years, resulting in volatile alternative index-based interest rates for these bonds. While the interest rates for these bonds have been extremely low, we continuously monitor the credit markets and evaluate our options with respect to our auction rate bonds.

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.

On May 31, 2011, Fitch upgraded its credit ratings for Westar Energy and KGE first mortgage bonds/senior secured debt to A- from BBB+. Fitch also upgraded its credit rating for Westar Energy unsecured debt to BBB+ from BBB and changed its outlook for the ratings from positive to stable. On December 22, 2011, Fitch assigned its F2 rating to Westar Energy's commercial paper program and also affirmed its other ratings provided in the table below with a stable outlook. On December 20, 2011, S&P assigned its A-2 short-term credit rating to Westar Energy's commercial paper program. Additionally, on January 6, 2012, 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.

As of February 15, 2012, our ratings with the agencies are as shown in the table below.

	Westar	KGE	Westar		Rating

	Energy First Mortgage Bond Rating	First Mortgage Bond Rating	Energy Unsecured Debt Rating	Westar Energy Commercial Paper	Outlook
Moody’s	A3	A3	Baa2	P-2	Stable
S&P	BBB+	BBB+	BBB	A-2	Stable
Fitch	A-	A-	BBB+	F2	Stable

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Certain of our derivative instruments contain collateral provisions subject to credit agency ratings of our senior unsecured debt. If our senior unsecured 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, 2011 and 2010, was $3.1 million and $1.6 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, 2011 and 2010, we would have been required to provide to our counterparties $0.5 million and $1.6 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

Common Stock Issuance

On May 19, 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, 2011, Westar Energy had 125.7 million shares issued and outstanding.

In November 2010, Westar Energy entered into a 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, which increased the total number of shares under the forward sale agreement to approximately 8.5 million shares. The underwriters receive a commission equal to 3.5% of the sales price of all shares sold under the agreement. Westar Energy agreed to settle the forward sale agreement within 18 months of the transaction date. On November 17, 2011, Westar Energy delivered approximately 8.5 million shares of common stock for proceeds of approximately $197.3 million as settlement of this forward sale agreement.

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 a year of the date each transaction is entered. Westar Energy has entered into forward sale transactions with respect to an aggregate of approximately 5.4 million shares of common stock. In late 2010, Westar Energy delivered approximately 1.2 million shares of common stock for proceeds of $26.4 million as partial settlement of the forward sale transactions. Westar Energy delivered approximately 4.2 million shares of common stock in 2011 for proceeds of approximately $91.9 million as complete settlement of this forward sale agreement.

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

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Summary of Cash Flows

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Cash flows from (used in):			
Operating activities	$462,696	$607,702	$478,905
Investing activities	(701,516)	(556,045)	(572,431)
Financing activities	241,431	(54,589)	97,222
Investing activities of discontinued operations	—	—	(22,750)
Net increase (decrease) in cash and cash equivalents	$2,611	$(2,932)	$(19,054)

Cash Flows from Operating Activities

Operating activities provided $462.7 million of cash in 2011 compared with cash provided from operating activities of $607.7 million during 2010. The decrease 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.

Operating activities provided $607.7 million of cash in 2010 compared with cash provided from operating activities of $478.9 million during 2009. This increase was due primarily to our having received $237.2 million more in customer receipts and our having received $27.1 million more in net tax refunds. With the consolidation of the VIEs discussed in Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," a portion of lease payments reported as operating cash flows in 2009 was reported as financing cash flows in 2010, which resulted in about a $23.0 million increase in operating cash flows in 2010. In addition, we contributed $16.2 million less to the Westar Energy pension trust, Westar Energy post-retirement benefit plan and Wolf Creek pension trust; and during 2009, we paid $16.2 million more for our share of Wolf Creek's refueling outage. Partially offsetting these increases was our having paid in 2010 $94.7 million more for fuel and purchased power and $61.9 million more for interest on corporate-owned life insurance (COLI) policies, which was the result of a policy change in the second quarter of 2009 under which we no longer pay interest on such policies in advance.

Cash Flows used in Investing Activities

Our principal use of cash for investing purposes relates to growing and improving our utility plant. The utility business is capital intensive and requires significant ongoing investment in plant. We invested $697.5 million in 2011, $540.1 million in 2010 and $555.6 million in 2009 in additions to property, plant and equipment. The increase from 2010 to 2011 was due principally to additions at our power plants, including air quality controls, and the addition of transmission facilities, which required significant amounts of cash.

Cash Flows from (used in) Financing Activities

Financing activities provided $241.4 million of cash in 2011 compared to using $54.6 million of cash in 2010. The increase 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 on-going 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.

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Financing activities used $54.6 million of cash in 2010. We used cash to pay $129.1 million in dividends, repay $30.3 million of long-term debt including VIEs and repay $16.1 million of short-term debt. Borrowings from COLI provided $74.1 million and proceeds from the issuance of common stock provided $54.7 million.

We received net cash flows from financing activities of $97.2 million in 2009. Proceeds from the issuance of long-term debt provided $347.5 million and proceeds from short-term debt provided $67.9 million. We used cash to repay $196.8 million of long-term debt and to pay $122.9 million in dividends.

Cash Flows used in Investing Activities of Discontinued Operations

In 2009, we paid Protection One, Inc. (Protection One) $22.8 million for its share of the net tax benefit related to the net operating loss carryforward arising from our sale of Protection One.

Future Cash Requirements

Our business requires significant capital investments. Through 2014, 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, borrowings under Westar Energy's revolving credit facilities, commercial paper 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 our company and 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 2011 and anticipated capital expenditures, including costs of removal, for 2012 through 2014 are shown in the following table.

	Actual 2011	2012	2013	2014
	(In Thousands)			
Generation:				
Replacements and other	$132,849	$159,800	$172,300	$164,600
Environmental	219,973	435,100	327,700	229,700
Nuclear fuel	18,506	21,900	44,200	20,600
Transmission (a)	188,840	136,500	200,700	197,400
Distribution:				
Replacements and other	58,159	48,200	33,500	26,500
Smart grid (b)	17,865	3,700	—	—
New customers	37,693	44,600	73,200	61,600
Other	23,566	21,500	23,600	12,100
Total capital expenditures	$697,451	$871,300	$875,200	$712,500

(a) In addition to amounts listed, we are investing in our Prairie Wind Transmission joint venture. In 2011, we incurred $2.0 million of expenditures related to this investment. In 2012, 2013 and 2014, we plan to incur expenditures

related to this joint venture of $1.8 million, $27.4 million and $3.4 million, respectively.
(b) Net of DOE matching grant.

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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 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 potentially new environmental requirements.

Over the next several years, we will also need significant amounts of cash to meet our long-term debt obligations. The principal amounts of our long-term debt maturities as of December 31, 2011, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2012	$—	$28,114
2013	—	25,941
2014	250,000	27,479
2015	—	27,933
2016	—	28,309
Thereafter	2,245,003	137,962
Total maturities	$2,495,003	$275,738

Pension Obligation

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 to our pension trust $50.0 million in 2011 and $22.4 million in 2010. We expect to contribute approximately $57.4 million in 2012. In 2011 and 2010, we also funded $10.0 million and $6.0 million, respectively, of Wolf Creek's pension plan contributions. In 2012, we expect to fund $11.5 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 all open forward sale transactions in 2011. The forward sale agreements were 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, 2011.

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. The amounts listed below include on-going needs for which contractual obligations existed as of December 31, 2011.

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Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2011.

	Total	2012	2013- 2014	2015 - 2016	Thereafter
	(In Thousands)				
Long-term debt (a)	$2,495,003	$—	$250,000	$—	$2,245,003
Long-term debt of VIEs (a)	275,738	28,114	53,420	56,242	137,962
Interest on long-term debt (b)	2,171,483	148,031	296,062	266,062	1,461,328
Interest on long-term debt of VIEs	80,314	16,214	26,074	19,128	18,898
Long-term debt, including interest	5,022,538	192,359	625,556	341,432	3,863,191
Pension and post-retirement benefit expected contributions (c)	79,700	79,700	—	—	—
Capital leases (d)	92,799	5,452	10,403	9,114	67,830
Operating leases (e)	77,620	16,247	25,739	18,114	17,520
Other obligations of VIEs (f)	20,699	3,296	3,461	3,626	10,316
Fossil fuel (g)	1,031,906	276,103	307,384	133,954	314,465
Nuclear fuel (h)	309,285	21,523	52,369	56,368	179,025
Unconditional purchase obligations	410,801	263,076	126,234	21,491	—
Unrecognized income tax benefits including interest (i)	120	120	—	—	—
Total contractual obligations	$7,045,468	$857,876	$1,151,146	$584,099	$4,452,347

(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, 2011.
(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 railcars 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) We have an additional $2.6 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, 2011.

Commercial Commitments

Our commercial commitments as of December 31, 2011, consist of outstanding letters of credit that expire in 2012, some of which automatically renew annually. The letters of credit are comprised of $0.7 million related to workers' compensation, $7.9 million related to new transmission projects, $1.9 million related to energy marketing and trading activities, and $2.3 million related to other operating activities, for a total outstanding balance of $12.8 million.

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OTHER INFORMATION

Changes in Prices

KCC Proceedings

We plan to file an application with the KCC in late February 2012 to adjust our prices to include updated transmission costs as reflected in our transmission formula rate effective January 1, 2012, discussed below. If approved, we estimate that the new prices will increase our annual retail revenues by approximately $36.7 million. We expect the KCC to issue an order on our request in April 2012.

On December 30, 2011, the KCC issued a final order approving a price adjustment we made earlier in 2011 to increase retail revenues to reflect adjustments to our transmission formula rate effective January 1, 2011, as discussed below. The new prices were effective April 14, 2011, and are expected to increase our annual retail revenues by approximately $17.4 million.

On October 27, 2011, 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 November 2011 and are expected to increase our annual retail revenues by approximately $4.9 million.

On August 25, 2011, we filed an application with the KCC proposing a $90.8 million increase in our annual retail prices. The primary drivers for the proposed increase were higher costs related to tree trimming, regulatory compliance, operating Wolf Creek and employee benefits. On February 6, 2012, we entered into a definitive Stipulation and Agreement agreed to or not opposed by all parties to this proceeding, with the exception of a consumer advocate. The settlement provides for a $50.0 million increase in our annual retail prices and is subject to KCC approval. Technical hearings commenced on February 13, 2012. We expect the KCC to issue an order on our request in April 2012.

On February 23, 2011, KCPL filed an application requesting that the KCC predetermine the ratemaking principles for and determine the appropriateness of approximately $1.2 billion of environmental upgrades proposed for La Cygne to comply with environmental regulations. We have a 50% interest in La Cygne and intervened in the proceeding. On August 19, 2011, the KCC issued an order ruling that the decision to make the upgrades is prudent and the $1.2 billion project cost estimate is reasonable. The KCC denied our request to collect our approximately $600.0 million share of the costs of the environmental upgrades through our ECRR. However, in the Stipulation and Agreement noted above, all parties to the agreement agreed that we may file an abbreviated rate review to update our prices to include capital costs associated with the project, which we plan to do.

On May 27, 2011, the KCC issued an order allowing us to adjust our prices to include costs associated with investments in air quality equipment made in 2010. The new prices were effective June 1, 2011, and are expected to increase our annual retail revenues by approximately $10.4 million.

FERC Proceedings

On October 15, 2011, we posted our updated transmission formula rate that includes projected 2012 transmission capital expenditures and operating costs. The updated rate was effective January 1, 2012, and is expected to increase our annual transmission revenues by approximately $38.2 million.

Our transmission formula rate that includes projected 2011 transmission capital expenditures and operating costs was effective January 1, 2011, and was expected to increase our annual transmission revenues by approximately

$15.9 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

On January 13, 2012, a breaker in a substation located at Wolf Creek failed. This failure was immediately followed by a loss of station power to Wolf Creek resulting in an unscheduled shutdown of Wolf Creek. We currently expect Wolf Creek to resume normal operations in late February to mid-March 2012 following the completion of repairs. This schedule assumes no discovery during the course of repairs of additional significant required work, and that all requirements of the NRC for resumption of normal operations are satisfied. Additional maintenance expenses and capital expenditures will be incurred as a result of this unscheduled outage.

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New Financial Regulation

In July 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 many of the implementing 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 more 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, 2011, and we expect to recognize these costs over a remaining weighted-average period of 1.9 years. Total unrecognized compensation cost related to RSU awards with performance measures was $3.3 million as of December 31, 2011, 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, diesel and oil, 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 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.

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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 2011 and 2010 were as follows:

	2011	2010
	(In Thousands)	
High	$272	$613
Low	31	26
Average	113	121

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 credit agency ratings of our senior unsecured debt. If our senior unsecured 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, 2011 and 2010, was $3.1 million and $1.6 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, 2011 and 2010, we would have been required to provide to our counterparties $0.5 million and $1.6 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

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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 variable interest rate exposure, utilizing various 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 $436.4 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2011. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $4.2 million. As of December 31, 2011, 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 lead 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 and negatively affect investment returns.

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 treasury yield hedge transactions with a total notional amount of $125.0 million. These transactions were measured at fair value by estimating the net present value of a series of payments using models with inputs such as the spread between the 30-year U.S. Treasury bill yield and the contracted, fixed yield. On January 20, 2012, we settled the Treasury yield hedge transactions for a total cost of $27.5 million. The cost of the hedge transactions will be amortized to interest expense over the term of the related debt.

Security Price Risk

We maintain the NDT, as required by the NRC and Kansas statue, to fund certain costs of nuclear plant decommissioning. As of December 31, 2011, investments in the NDT were allocated 61% to equity securities, 28% to debt securities, 6% to combination debt/equity securities, 5% to real estate securities and less than 1% to cash equivalents. The fair value of the NDT investments was $130.3 million as of December 31, 2011, and $127.0 million as of December 31, 2010. 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 $13.0 million decrease in the value of the NDT as of December 31, 2011.

We also maintain a trust to fund non-qualified retirement benefits. As of December 31, 2011, 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 $40.2 million as of December 31, 2011, and $39.4 million as of December 31, 2010. 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 $4.0 million decrease in the value of the trust as of December 31, 2011.

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.

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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.

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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, 2011. 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, 2011, 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, 2011, 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, 2011, 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 as of and for the year ended December 31, 2011 of the Company and our report dated February 23, 2012, which includes an explanatory paragraph related to the adoption of a new accounting standard in 2010, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 23, 2012

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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, 2011 and 2010 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, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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.

As discussed in Note 17 to the consolidated financial statements, the Company adopted a new accounting standard with respect to the consolidation of variable interest entities effective January 1, 2010.

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, 2011, 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 23, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 23, 2012

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

	As of December 31,	
	2011	2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$3,539	$928
Accounts receivable, net of allowance for doubtful accounts of $7,384 and $5,729, respectively	226,428	227,700
Fuel inventory and supplies	229,118	206,867
Energy marketing contracts	8,180	13,005
Taxes receivable	5,334	16,679
Deferred tax assets	394	30,248
Prepaid expenses	13,078	12,413
Regulatory assets	123,818	73,480
Other	23,696	20,289
Total Current Assets	633,585	601,609
PROPERTY, PLANT AND EQUIPMENT, NET	6,411,922	5,964,439
PROPERTY, PLANT AND EQUIPMENT OF VARIABLE INTEREST ENTITIES, NET	333,494	345,037
OTHER ASSETS:		
Regulatory assets	922,272	787,585
Nuclear decommissioning trust	130,270	126,990
Other	251,308	253,978
Total Other Assets	1,303,850	1,168,553
TOTAL ASSETS	$8,682,851	$8,079,638
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$—	$61
Current maturities of long-term debt of variable interest entities	28,114	30,155
Short-term debt	286,300	226,700
Accounts payable	187,428	187,954
Accrued taxes	52,451	45,534
Energy marketing contracts	6,353	9,670
Accrued interest	77,437	77,771
Regulatory liabilities	40,857	33,779
Other	148,347	171,222
Total Current Liabilities	827,287	782,846
LONG-TERM LIABILITIES:		
Long-term debt, net	2,491,109	2,490,871
Long-term debt of variable interest entities, net	249,283	278,162
Deferred income taxes	1,110,463	1,102,625
Unamortized investment tax credits	164,175	101,345
Regulatory liabilities	230,530	233,295
Accrued employee benefits	592,617	483,769
Asset retirement obligations	142,508	125,999
Other	74,138	66,888
Total Long-Term Liabilities	5,054,823	4,882,954

COMMITMENTS AND CONTINGENCIES (See Notes 13 and 15)		
TEMPORARY EQUITY (See Note 11)	—	3,465
EQUITY:		
Westar Energy Shareholders' Equity:		
Cumulative preferred stock, par value $100 per share; authorized 600,000 shares; issued and outstanding 214,363 shares	21,436	21,436
Common stock, par value $5 per share; authorized 275,000,000 and150,000,000 shares, respectively; issued and outstanding 125,698,396 shares and 112,128,068 shares, respectively	628,492	560,640
Paid-in capital	1,639,503	1,398,580
Retained earnings	501,216	423,647
Total Westar Energy Shareholders' Equity	2,790,647	2,404,303
Noncontrolling Interests	10,094	6,070
Total Equity	2,800,741	2,410,373
TOTAL LIABILITIES AND EQUITY	$8,682,851	$8,079,638

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

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

	Year Ended December 31,		
	2011	2010	2009
REVENUES	$2,170,991	$2,056,171	$1,858,231
OPERATING EXPENSES:			
Fuel and purchased power	630,793	583,361	534,864
Operating and maintenance	557,752	520,409	516,930
Depreciation and amortization	285,322	271,937	251,534
Selling, general and administrative	184,695	207,607	199,961
Total Operating Expenses	1,658,562	1,583,314	1,503,289
INCOME FROM OPERATIONS	512,429	472,857	354,942
OTHER INCOME (EXPENSE):			
Investment earnings	9,301	7,026	12,658
Other income	8,652	5,369	7,128
Other expense	(18,398)	(16,655)	(17,188)
Total Other (Expense) Income	(445)	(4,260)	2,598
Interest expense	172,460	174,941	157,360
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	339,524	293,656	200,180
Income tax expense	103,344	85,032	58,850
INCOME FROM CONTINUING OPERATIONS	236,180	208,624	141,330
Results of discontinued operations, net of tax	—	—	33,745
NET INCOME	236,180	208,624	175,075
Less: Net income attributable to noncontrolling interests	5,941	4,728	—
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY	230,239	203,896	175,075
Preferred dividends	970	970	970
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$229,269	$202,926	$174,105
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY (see Note 2):			
Basic earnings available from continuing operations	$1.95	$1.81	$1.28
Discontinued operations, net of tax	—	—	0.30
Basic earnings per common share	$1.95	$1.81	$1.58
Diluted earnings available from continuing operations	$1.93	$1.80	$1.28
Discontinued operations, net of tax	—	—	0.30
Diluted earnings per common share	$1.93	$1.80	$1.58
Average equivalent common shares outstanding	116,890,552	111,629,292	109,647,689
DIVIDENDS DECLARED PER COMMON SHARE	$1.28	$1.24	$1.20
AMOUNTS ATTRIBUTABLE TO WESTAR ENERGY:			
Income from continuing operations	$230,239	$203,896	$141,330
Results of discontinued operations, net of tax	—	—	33,745
Net income	$230,239	$203,896	$175,075

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

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

	Year Ended December 31,		
	2011	2010	2009
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$236,180	$208,624	$175,075
Discontinued operations, net of tax	—	—	(33,745)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	285,322	271,937	251,534
Amortization of nuclear fuel	21,151	25,089	16,161
Amortization of deferred regulatory gain from sale leaseback	(5,495)	(5,495)	(5,495)
Amortization of corporate-owned life insurance	25,650	20,650	22,116
Non-cash compensation	8,422	11,373	5,133
Net changes in energy marketing assets and liabilities	926	(1,284)	8,972
Net deferred income taxes and credits	111,723	120,169	46,447
Stock-based compensation excess tax benefits	(1,180)	(641)	(448)
Allowance for equity funds used during construction	(5,550)	(3,104)	(5,031)
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	(1,638)	(11,434)	(17,159)
Fuel inventory and supplies	(21,485)	(12,266)	10,466
Prepaid expenses and other	(50,138)	8,475	(10,635)
Accounts payable	3,008	30,330	(15,115)
Accrued taxes	18,633	27,565	30,493
Other current liabilities	(107,012)	(80,660)	13,572
Changes in other assets	(10,167)	(42,544)	73,784
Changes in other liabilities	(16,369)	40,918	(87,220)
Cash Flows from Operating Activities	462,696	607,702	478,905
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(697,451)	(540,076)	(555,637)
Purchase of securities within trusts	(49,737)	(192,350)	(64,016)
Sale of securities within trusts	47,534	191,603	61,096
Investment in corporate-owned life insurance	(19,214)	(19,162)	(17,724)
Proceeds from investment in corporate-owned life insurance	1,295	2,204	1,748
Proceeds from federal grant	8,561	3,180	—
Investment in affiliated company	(1,943)	(280)	(818)
Proceeds from sale of non-utility investments	9,246	—	—
Investment in non-utility investments	(3,656)	—	—
Other investing activities	3,849	(1,164)	2,920
Cash Flows used in Investing Activities	(701,516)	(556,045)	(572,431)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	54,081	(16,060)	67,860
Proceeds from long-term debt	—	—	347,507
Retirements of long-term debt	(371)	(1,695)	(196,821)
Retirements of long-term debt of variable interest entities	(30,159)	(28,610)	—
Repayment of capital leases	(2,233)	(2,981)	(10,190)

Borrowings against cash surrender value of corporate-owned life insurance	67,562	74,134	10,299
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(3,421)	(3,430)	(3,531)
Stock-based compensation excess tax benefits	1,180	641	448
Issuance of common stock	294,942	54,651	4,587
Distributions to shareholders of noncontrolling interests	(1,917)	(2,093)	—
Cash dividends paid	(138,233)	(129,146)	(122,937)
Cash Flows from (used in) Financing Activities	241,431	(54,589)	97,222
CASH FLOWS USED IN INVESTING ACTIVITIES OF DISCONTINUED OPERATIONS:			
Payment of settlement to former subsidiary	—	—	(22,750)
Cash Flows used in Investing Activities of Discontinued Operations	—	—	(22,750)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,611	(2,932)	(19,054)
CASH AND CASH EQUIVALENTS:			
Beginning of period	928	3,860	22,914
End of period	$3,539	$928	$3,860

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

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

	Westar Energy 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, 2008	214,363	$21,436	108,311,135	$541,556	$1,326,391	$318,197	$ —	$2,207,580
Net income	—	—	—	—	—	175,075	—	175,075
Issuance of common stock	—	—	760,865	3,804	10,569	—	—	14,373
Preferred dividends	—	—	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	—	—	(132,103)	—	(132,103)
Transfer to temporary equity	—	—	—	—	(20)	—	—	(20)
Amortization of restricted stock	—	—	—	—	4,524	—	—	4,524
Stock compensation and tax benefit	—	—	—	—	(1,674)	—	—	(1,674)
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 common stock	—	—	3,056,068	15,280	50,759	—	—	66,039
Preferred dividends	—	—	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	—	—	(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 common stock	—	—	13,570,328	67,852	243,081	—	—	310,933
Preferred dividends	—	—	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	—	—	(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

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

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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 688,000 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 on-going basis, including those related to valuation of commodity contracts, depreciation, unbilled revenue, valuation of investments, valuation of our energy marketing portfolio, 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.

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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,	
	2011	2010
	(In Thousands)	
Fuel inventory	$86,408	$79,938
Supplies	142,710	126,929
Total	$229,118	$206,867

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,		
	2011	2010	2009
	(Dollars In Thousands)		
Borrowed funds	$5,589	$4,295	$4,857
Equity funds	5,550	3,104	5,031
Total	$11,139	$7,399	$9,888
Average AFUDC Rates	3.6%	2.6%	4.2%

We charge maintenance costs and replacement 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 an 18-month operating cycle the 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. These rates are based on an average annual composite basis using group rates that approximated 3.0% in 2011, 2.9% in 2010 and 3.0% in 2009.

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

	Years
Fossil fuel generating facilities	7 to 78
Nuclear fuel generating facility	33 to 62
Wind generating facilities	19 to 20
Transmission facilities	15 to 67
Distribution facilities	15 to 70
Other	6 to 28

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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 $44.8 million as of December 31, 2011, and $48.0 million as of December 31, 2010. The cost of nuclear fuel charged to fuel and purchased power expense was $24.6 million in 2011, $29.2 million in 2010 and $20.1 million in 2009.

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,	
	2011	2010
	(In Thousands)	
Cash surrender value of policies	$1,345,443	$1,280,615
Borrowings against policies	(1,208,389)	(1,144,248)
Corporate-owned life insurance, net	$137,054	$136,367

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 $54.0 million as of December 31, 2011, and $53.8 million as of December 31, 2010.

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 as current energy marketing assets and 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.

Normal Purchases and Normal Sales Exception

Determining whether a contract qualifies for the normal purchases and normal sales exception requires that we exercise judgment on whether the contract will physically deliver and requires that we ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and price is not tied to an unrelated underlying derivative.

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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 Taxes

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 as declared on an equal basis with 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.

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

	Year Ended December 31,		
	2011	2010	2009
	(Dollars In Thousands, Except Per Share Amounts)		
Income from continuing operations	$236,180	$208,624	$141,330
Less: Income attributable to noncontrolling interests	5,941	4,728	—
Income from continuing operations attributable to Westar Energy	230,239	203,896	141,330
Less: Preferred dividends	970	970	970
Income from continuing operations allocated to RSUs	772	1,259	541
Income from continuing operations attributable to common stock	$228,497	$201,667	$139,819
Weighted average equivalent common shares outstanding – basic	116,890,552	111,629,292	109,647,689
Effect of dilutive securities:			
RSUs	188,025	140,077	—
Forward sale agreements	1,211,645	245,496	—
Employee stock options	—	59	481
Weighted average equivalent common shares outstanding – diluted (a)	118,290,222	112,014,924	109,648,170
Earnings from continuing operations per common share, basic	$1.95	$1.81	$1.28
Earnings from continuing operations per common share, diluted	$1.93	$1.80	$1.28

(a) For the years ended December 31, 2011, 2010 and 2009, we had no antidilutive shares.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$145,570	$145,463	$144,964
Interest on financing activities of VIEs	18,167	20,191	—
Income taxes, net of refunds	(17,519)	(34,980)	(7,870)
NON-CASH INVESTING TRANSACTIONS:			
Property, plant and equipment additions	105,435	64,423	21,614
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	15,103	18,777	12,168
Debt of VIEs	—	337,951	—
Capital lease for JEC 8% leasehold interest	—	(106,423)	—
Assets acquired through capital leases	43,011	910	2,818

Investment Earnings - Sale of Non-utility Investment

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

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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,	
	2011	2010
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$560,915	$431,016
Amounts due from customers for future income taxes, net	168,804	172,181
Depreciation	76,298	79,770
Debt reacquisition costs	66,856	73,099
Treasury yield hedges	33,753	—
Storm costs	25,747	34,741
Wolf Creek outage	25,033	9,637
Asset retirement obligations	22,196	21,546
Retail energy cost adjustment	19,587	—
Energy efficiency program costs	16,521	10,980
Disallowed plant costs	16,236	16,354
Ad valorem tax	6,622	5,680
Other regulatory assets	7,522	6,061
Total regulatory assets	$1,046,090	$861,065
Regulatory Liabilities:		
Deferred regulatory gain from sale leaseback	$97,541	$103,036
Removal costs	82,338	70,342
Retail energy cost adjustment	25,225	16,402
La Cygne dismantling costs	15,680	13,268
Nuclear decommissioning	12,544	25,467
Other post-retirement benefits costs	11,125	6,943
Kansas tax credits	8,497	3,565
Fuel supply and electricity contracts	6,177	7,800
Ad valorem tax	—	4,934
Treasury yield hedges	—	7,711
Other regulatory liabilities	12,260	7,606
Total regulatory liabilities	$271,387	$267,074

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 $512.5 million for pension and post-retirement benefit obligations and $48.4 million for actual pension expense in excess of the amount of such expense recognized in setting our prices. During 2012, we will amortize to expense approximately $47.0 million of the benefit obligations. We expect to amortize the excess pension expense as part of resetting base prices. We do not earn a return on this asset.

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- 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 the 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.

- 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.

- Wolf Creek outage: Wolf Creek incurs a refueling and maintenance outage approximately every 18 months. The expenses associated with these refueling and maintenance outages are deferred and amortized over the period between such planned outages. We do not earn a return on this asset.

- Asset retirement obligations: Represents amounts associated with our AROs as discussed in Note 14, "Asset Retirement Obligations." We recover these amounts over the life of the related plant. We do not earn a return on this asset.

- Retail energy cost adjustment: We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. This item represents the actual cost of fuel consumed in producing electricity and the cost of purchased power in excess of the amounts we have collected from customers. We expect to recover in our prices this shortfall over a one-year period. For the reporting period, we had two retail jurisdictions, each with a separate cost of fuel. 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.

- 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.

- 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 on one-year period. We do not earn a return on this asset.

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- Other regulatory assets: Includes various regulatory assets that individually are small in relation to the total regulatory asset balance. Other regulatory assets have various recovery periods. We do not earn a return on any of these assets.

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

- Deferred regulatory gain from sale leaseback: Represents the gain KGE recorded on the 1987 sale and leaseback of its 50% interest in La Cygne Generating Station (La Cygne) unit 2. We amortize the gain over the lease term.

- Removal costs: Represents amounts collected, but not yet spent, to dispose of plant assets that do not represent legal retirement obligations. This liability will be discharged as removal costs are incurred.

- 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. For the reporting period, we had two retail jurisdictions, each with a separate cost of fuel. This resulted in us simultaneously reporting both a regulatory asset and a regulatory liability for this item.

- 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.

- Nuclear decommissioning: We have a legal obligation to decommission Wolf Creek at the end of its useful life. This item represents the difference between the fair value of the assets held in a decommissioning trust and the fair value of our ARO. See Note 5, "Financial Investments" and Note 14, "Asset Retirement Obligations," for information regarding our nuclear decommissioning trust (NDT) and our ARO.

- 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. At the time of a future rate review, we expect to credit this excess to customers as part of resetting our base prices.

- 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.

- 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.

- Ad valorem tax: Represents amounts collected in our prices in excess of actual costs incurred for property taxes. We will refund to customers this excess recovery over a one-year period.

- Treasury yield hedges: Represents the effective portion of the gains 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.

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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.

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KCC Proceedings

General and Abbreviated Rate Reviews

On August 25, 2011, we filed an application with the KCC proposing a $90.8 million increase in our annual retail prices. The primary drivers for the proposed increase were higher costs related to tree trimming, regulatory compliance, operating Wolf Creek and employee benefits. On February 6, 2012, we entered into a definitive Stipulation and Agreement agreed to or not opposed by all parties to this proceeding, with the exception of a consumer advocate. The settlement provides for a $50.0 million increase in our annual retail prices and is subject to KCC approval. Technical hearings commenced on February 13, 2012. We expect the KCC to issue an order on our request in April 2012.

On January 27, 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 February 2010 and were expected to increase our annual retail revenues by approximately $17.1 million.

On January 21, 2009, the KCC issued an order expected to increase our annual retail revenues by approximately $130.0 million to reflect investments in natural gas generation facilities, wind generation facilities and other capital projects, costs to repair damage to our electrical system, which were previously deferred as a regulatory asset, higher operating costs in general and an updated capital structure. The new prices were effective February 3, 2009.

Environmental Costs

On February 23, 2011, Kansas City Power & Light Company (KCPL) filed an application requesting that the KCC predetermine the ratemaking principles for and determine the appropriateness of approximately $1.2 billion of environmental upgrades proposed for La Cygne to comply with environmental regulations. We have a 50% interest in La Cygne and intervened in the proceeding. On August 19, 2011, the KCC issued an order ruling that the decision to make the upgrades is prudent and the $1.2 billion project cost estimate is reasonable. The KCC denied our request to collect our approximately $600.0 million share of the costs of the environmental upgrades through our environmental cost recovery rider (ECRR). However, in the Stipulation and Agreement noted above, all parties to the agreement agreed that we may file an abbreviated rate review to update our prices to include capital costs associated with the project, which we plan to do.

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. Following is additional information regarding such price adjustments.

- On May 27, 2011, the KCC issued an order allowing us to increase our annual retail revenues by approximately $10.4 million effective June 1, 2011.
- On May 25, 2010, the KCC issued an order allowing us to increase our annual retail revenues by approximately $13.8 million effective June 1, 2010.
- On May 29, 2009, the KCC issued an order allowing us to increase our annual retail revenues by approximately $32.5 million effective June 1, 2009.

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. Following is information regarding such price adjustments.

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On December 30, 2011, the KCC issued an order allowing us to increase our annual retail revenues by approximately $17.4 million effective April 14, 2011.

- On June 11, 2010, the KCC issued an order allowing us to increase our annual retail revenues by approximately $6.4 million effective March 16, 2010.
- On March 6, 2009, the KCC issued an order allowing us to increase our annual retail revenues by approximately $31.8 million effective March 13, 2009.

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Energy Efficiency

We make annual filings with the KCC to adjust our prices to include previously deferred amounts associated with various energy efficiency programs. Following is information regarding such price adjustments.

- On October 27, 2011, the KCC issued an order allowing us to increase our annual retail revenues by approximately $4.9 million to recover additional deferred amounts effective November 2011.
- On October 29, 2010, the KCC issued an order allowing us to recover approximately $5.8 million of previously deferred amounts effective November 2010.

Other

On September 11, 2009, the KCC issued an order, effective January 1, 2009, allowing us to establish 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 will accumulate such regulatory asset or liability between general rate reviews and expect to amortize the accumulated amount as part of resetting our base prices during general rate reviews.

FERC Proceedings

On October 15 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. Below is additional information regarding our transmission formula rates posted over the last few years.

- Our transmission formula rate that includes projected 2012 costs was effective January 1, 2012, and is expected to increase our annual transmission revenues by approximately $38.2 million.
- Our transmission formula rate that included projected 2011 costs was effective January 1, 2011, and was expected to increase our annual transmission revenues by approximately $15.9 million.
- Our transmission formula rate that included projected 2010 costs was effective January 1, 2010, and was expected to increase our annual transmission revenues by approximately $16.8 million.

On January 12, 2010, the Federal Energy Regulatory Commission (FERC) issued an order accepting our request to implement a cost-based formula rate for electricity sales to wholesale customers. The use of a cost-based formula rate allows us to annually adjust our prices to reflect changes in our cost of service. The cost-based formula rate was effective December 1, 2009.

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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, real estate investments 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 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 as reported by the trustee. In addition, we maintain certain level 3 investments in private equity and real estate securities 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.

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. See "-Recurring Fair Value

Measurements" and "-Derivative Instruments" below for additional information.

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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 financial instruments.

	Carrying Value		Fair Value	
	As of December 31,			
	2011	2010	2011	2010
	(In Thousands)			
Fixed-rate debt	$2,373,063	$2,373,373	$2,623,993	$2,570,648
Fixed-rate debt of VIEs	275,738	308,317	306,027	341,328

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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, 2011	Level 1	Level 2	Level 3	Total
	(In Thousands)			
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
As of December 31, 2010				
Assets:				
Energy Marketing Contracts	$2,432	$6,258	$13,787	$22,477
Nuclear Decommissioning Trust:				
Domestic equity	—	60,586	2,867	63,453
International equity	—	18,966	—	18,966
Core bonds	—	31,906	—	31,906
High-yield bonds	—	9,267	305	9,572
Real estate securities	—	—	3,049	3,049
Cash equivalents	44	—	—	44
Total Nuclear Decommissioning Trust	44	120,725	6,221	126,990
Trading Securities:				
Domestic equity	—	21,207	—	21,207
International equity	—	5,128	—	5,128
Core bonds	—	13,077	—	13,077
Total Trading Securities	—	39,412	—	39,412
Treasury Yield Hedges	—	7,711	—	7,711

Total Assets Measured at Fair Value	$2,476	$174,106	$20,008	$196,590
Liabilities:				
Energy Marketing Contracts	$1,888	$5,820	$1,972	$9,680

We do not offset the fair value of energy marketing contracts executed with the same counterparty. 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. As of December 31, 2010, we had no right to reclaim cash collateral and had recorded $0.7 million for our obligation to return cash collateral.

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The following table provides reconciliations of assets and liabilities measured at fair value using significant level 3 inputs for the years ended December 31, 2011 and 2010.

	Energy Marketing Contracts, net	Nuclear Decommissioning Trust Domestic Equity	High-yield Bonds	Real Estate Securities	Net Balance
	(In Thousands)				
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
Balance as of December 31, 2009	$4,310	$2,262	$5,741	$3,635	$15,948
Total realized and unrealized gains (losses) included in:					
Earnings (a)	(2,585)	—	—	—	(2,585)
Regulatory assets	3,311 (b)	—	—	—	3,311
Regulatory liabilities	8,148 (b)	16	367	(586)	7,945
Purchases, issuances and settlements, net	(1,369)	589	(5,803)	—	(6,583)
Balance as of December 31, 2010	$11,815	$2,867	$305	$3,049	$18,036

(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.

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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, 2011 and 2010, attributed to level 3 assets and liabilities.

	Year Ended December 31, 2011				
	Energy	Nuclear Decommissioning Trust			
	Marketing Contracts, net	Domestic Equity	High-yield Bonds	Real Estate Securities	Net Balance
	(In Thousands)				
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
	Year Ended December 31, 2010				
Total unrealized gains (losses) included in:					
Earnings (a)	$(1,441)	$—	$—	$—	$(1,441)
Regulatory assets	180 (b)	—	—	—	180
Regulatory liabilities	2,633 (b)	23	(31)	(586)	2,039
Total	$1,372	$23	$(31)	$(586)	$778

(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.

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Some of our investments in the NDT and our trading securities portfolio 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, 2011		As of December 31, 2010		As of December 31, 2011	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
	(In thousands)					
Nuclear Decommissioning Trust:						
Domestic equity	$3,931	$1,914	$2,867	$2,523	(a)	(a)
High-yield bonds	—	—	305	—	(b)	(b)
Real estate securities	7,095	—	3,049	—	(c)	(c)
Total Nuclear Decommissioning Trust	$11,026	$1,914	$6,221	$2,523		
Trading Securities:						
Domestic equity	$21,175	$—	$21,207	$—	Upon Notice	1 day
International equity	4,896	—	5,128	—	Upon Notice	1 day
Core bonds	13,961	—	13,077	—	Upon Notice	1 day
Total Trading Securities	40,032	—	39,412	—		
Total	$51,058	$1,914	$45,633	$2,523		

(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.

(b) We completely settled this fund 2011.

(c) The nature of this investment requires relatively long holding periods which do not necessarily accommodate ready liquidity. In addition, adverse financial conditions affecting residential and commercial real estate markets have further limited liquidity associated with this investment.

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 2010 we did not incur any additional AROs. In 2011, we incurred $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.

The fair value is measured 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, we must estimate the cost of basic inputs such as labor, energy, materials and disposal and make assumptions on the method of disposal or decommissioning. To determine the appropriate discount rate, we use inputs such as inflation rates, short and long-term yields for U.S. government securities and our nonperformance risk. The current estimate to decommission Wolf Creek assumes that the Department of Energy will have removed all of Wolf Creek's spent nuclear fuel and high-level radioactive waste by the time the rest of the plant has been decommissioned. 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."

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Derivative Instruments

Cash Flow Hedges

We have entered into treasury yield hedge transactions for a total notional amount of $125.0 million in an attempt to manage our interest rate risk associated with a future anticipated issuance of fixed rate debt. Such transactions are designated and qualify as cash flow hedges and are 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 will 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 of the losses on these transactions. During 2011, we recorded $0.2 million of hedge ineffectiveness losses in interest expense on our consolidated statements of income. As of December 31, 2010, we had recorded $7.7 million in other assets to reflect the fair value of these transactions and recorded this same amount in long-term regulatory liabilities to reflect the effective portion of the gains on these transactions. On January 20, 2012, we settled the treasury yield hedge transactions for a total cost of $27.5 million. The cost of the hedge transactions will be amortized to interest expense over the term of the related debt.

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 energy marketing contracts 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, 2011

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

Commodity Derivatives Not Designated as Hedging Instruments as of December 31, 2010

Asset Derivatives		Liability Derivatives	
Balance Sheet Location	Fair Value (In Thousands)	Balance Sheet Location	Fair Value (In Thousands)

Current assets:		Current liabilities:	
Energy marketing contracts	$13,005	Energy marketing contracts	$9,670
Other assets:		Long-term liabilities:	
Other	9,472	Other	10
Total	$22,477	Total	$9,680

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The following table presents how changes in the fair value of commodity derivative instruments affected our consolidated financial statements for the years ended December 31, 2011 and 2010.

Location	Year Ended December 31, 2011		Year Ended December 31, 2010
	Net Gain Recognized	Net Loss Recognized	Net Gain Recognized
	(In Thousands)		
Revenues increase	$1,569	$—	$712
Regulatory assets increase (decrease)	—	374	(7,604)
Regulatory liabilities (decrease) increase	—	(1,623)	1,799

As of December 31, 2011 and 2010, we had under contract the following commodity derivatives.

	Unit of Measure	Net Quantity as of December 31, 2011	December 31, 2010
Electricity	MWh	1,834,253	2,791,966
Natural Gas	MMBtu	1,467,500	1,150,000

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, diesel and oil, 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 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.

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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 credit agency ratings of our senior unsecured debt. If our senior unsecured 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, 2011 and 2010, was $3.1 million and $1.6 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, 2011 and 2010, we would have been required to provide to our counterparties $0.5 million and $1.6 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

5. FINANCIAL INVESTMENTS

We report some of 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 in a trust used to fund retirement benefits that we classify as trading securities. We include unrealized gains or losses on these securities in investment earnings on our consolidated statements of income. For the years ended December 31, 2011, 2010 and 2009, we recorded unrealized gains of $0.3 million, $4.3 million and $11.3 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, 2011 and 2010. The core bond fund has a requirement that at least 80% of funds are invested in investment grade U.S. corporate and government fixed income securities, including mortgage-backed securities. As of December 31, 2011, the fair value of available-for-sale debt securities in the core, high-yield and emerging market bond funds was $36.4 million. As of December 31, 2011, the NDT did not have investments in debt securities outside of investment funds.

Using the specific identification method to determine cost, we realized a $1.3 million gain in 2011, a $13.2 million gain in 2010 and a $7.8 million loss in 2009 on our available-for-sale securities. 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.

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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, 2011 and 2010.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Allocation
	(In Thousands)				
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 %
As of December 31, 2010					
Domestic equity	$58,592	$4,972	$(111)	$63,453	50 %
International equity	17,249	1,717	—	18,966	15 %
Core bonds	32,054	—	(148)	31,906	25 %
High-yield bonds	9,086	486	—	9,572	8 %
Real estate securities	6,207	—	(3,158)	3,049	2 %
Cash equivalents	44	—	—	44	<1%
Total	$123,232	$7,175	$(3,417)	$126,990	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, 2011 and 2010.

	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, 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)
As of December 31, 2010						
Domestic equity	$2,867	$(111)	$—	$—	$2,867	$(111)
Core bonds	31,906	(148)	—	—	31,906	(148)
Real estate securities	—	—	3,049	(3,158)	3,049	(3,158)
Total	$34,773	$(259)	$3,049	$(3,158)	$37,822	$(3,417)

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6. PROPERTY, PLANT AND EQUIPMENT

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

	As of December 31, 2011	2010
	(In Thousands)	
Electric plant in service	$8,703,278	$8,254,884
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,703,372)	(3,563,566)
	5,802,224	5,493,636
Construction work in progress	534,003	392,701
Nuclear fuel, net	75,695	78,102
Net property, plant and equipment	$6,411,922	$5,964,439

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

	As of December 31, 2011	2010
	(In Thousands)	
Electric plant of VIEs	$543,548	$543,593
Accumulated depreciation of VIEs	(210,054)	(198,556)
Net property, plant and equipment of VIEs	$333,494	$345,037

We recorded depreciation expense on property, plant and equipment of $262.6 million in 2011, $249.2 million in 2010 and $228.6 million in 2009. Approximately $9.8 million and $9.7 million of depreciation expense in 2011 and 2010, respectively, was attributable to property, plant and equipment of VIEs.

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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, 2011, 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	$332,862	$148,890	$68,724	368	50
JEC unit 1 (a)	July 1978	488,180	207,206	49,755	666	92
JEC unit 2 (a)	May 1980	508,327	186,660	—	667	92
JEC unit 3 (a)	May 1983	677,277	268,909	6,770	672	92
Wolf Creek (b)	Sept. 1985	1,515,165	732,651	37,740	547	47
State Line (c)	June 2001	112,024	45,841	1,579	201	40
Total		$3,633,835	$1,590,157	$164,568	3,121	

(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 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 $173.1 million as of December 31, 2011. 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

On December 9, 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 repay borrowings under Westar Energy's revolving credit facilities, for capital expenditures and/or for other general corporate purposes. As of December 31, 2011, Westar Energy had no commercial paper outstanding.

On September 29, 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 on September 29, 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, 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. As of December 31, 2010, $226.7 million had been borrowed and an additional $21.5 million of letters of credit had been issued under Westar Energy's previous $730.0 million revolving credit facility.

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On February 18, 2011, Westar Energy entered into a revolving credit facility with a syndicate of banks for $270.0 million. The commitments under this facility terminate on February 18, 2015. 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 $400.0 million, both subject to lender participation. All borrowings under the facility are secured by KGE first mortgage bonds. As of December 31, 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 1.49% and 0.61% as of December 31, 2011 and 2010, respectively. Additional information regarding our short-term debt is as follows.

	As of December 31,	
	2011	2010
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$362,946	$213,041
Weighted daily average interest rates during the year, excluding fees	0.82 %	0.63 %

Our interest expense on short-term debt was $3.9 million in 2011, $1.9 million in 2010 and $2.2 million in 2009.

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9. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

	As of December 31,	
	2011	2010
	(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	150,000
8.625% due 2018	300,000	300,000
	1,350,000	1,350,000
Pollution control bond series:		
Variable due 2032, 0.22% as of December 31, 2011; 0.60% as of December 31, 2010	45,000	45,000
Variable due 2032, 0.24% as of December 31, 2011; 0.54% as of December 31, 2010	30,500	30,500
5.00% due 2033	57,245	57,530
	132,745	133,030
Other long-term debt:		
4.36% equipment financing loan due 2011	—	61
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	13,343
Variable due 2027, 0.28% as of December 31, 2011; 0.54% as of December 31, 2010	21,940	21,940
5.30% due 2031	108,600	108,600
5.30% due 2031	18,900	18,900
Variable due 2032, 0.28% as of December 31, 2011; 0.54% as of December 31, 2010	14,500	14,500
Variable due 2032, 0.28% as of December 31, 2011; 0.54% as of December 31, 2010	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
	387,258	387,283
Total long-term debt	2,495,003	2,495,374
Unamortized debt discount (a)	(3,894)	(4,442)
Long-term debt due within one year	—	(61)
Long-term debt, net	$2,491,109	$2,490,871
Variable Interest Entities		
7.77% due 2013 (b)	$2,583	$5,095
6.99% due 2014 (b)	2,094	3,237
5.92 % due 2019 (b)	22,748	31,171
5.647% due 2021 (b)	248,313	266,393
Total long-term debt of variable interest entities	275,738	305,896
Unamortized debt premium (a)	1,659	2,421
Long-term debt of variable interest entities due within one year	(28,114)	(30,155)
Long-term debt of variable interest entities, net	$249,283	$278,162

(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.

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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, 2011, approximately $1.0 billion 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, 2011, based on an assumed interest rate of 4.125%, approximately $436.2 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, 2011, we had $121.9 million of variable rate, tax-exempt bonds. Interest rates payable under these bonds had historically been set by auctions, which occur every 35 days. However, auctions for these bonds have failed over the past few years, resulting in volatile alternative index-based interest rates for these bonds. While the interest rates for these bonds have been extremely low, we continuously monitor the credit markets and evaluate our options with respect to our auction rate bonds.

On August 3, 2009, Westar Energy repaid $145.1 million principal amount of 7.125% unsecured senior notes with borrowings under Westar Energy's revolving credit facility.

On June 11, 2009, KGE issued $300.0 million principal amount of first mortgage bonds at a discount yielding 6.725%, bearing stated interest at 6.70% and maturing on June 15, 2019. KGE received net proceeds of $297.5 million.

Proceeds from the issuance of first mortgage bonds were used to repay borrowings under Westar Energy's revolving credit facility, with such borrowed amounts principally related to investments in capital equipment, as well as for working capital and general corporate purposes.

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. We use these ratios solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2011.

Maturities

The principal amounts of our long-term debt maturities as of December 31, 2011, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2012	$—	$28,114
2013	—	25,941
2014	250,000	27,479
2015	—	27,933

2016	—	28,309
Thereafter	2,245,003	137,962
Total maturities	$2,495,003	$275,738

Interest expense on long-term debt was $142.6 million in 2011, $144.1 million in 2010 and $139.6 million in 2009. Interest expense on long-term debt of VIEs was $16.8 million in 2011 and $18.7 million in 2010.

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10. TAXES

Income tax expense is comprised of the following components.

	Year Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Income Tax Expense (Benefit) from Continuing Operations:			
Current income taxes:			
Federal	$(8,575)	$(32,107)	$2,428
State	196	(3,030)	9,975
Deferred income taxes:			
Federal	93,089	102,568	46,148
State	21,337	20,305	3,003
Investment tax credit amortization	(2,703)	(2,704)	(2,704)
Income tax expense from continuing operations	$103,344	$85,032	$58,850
Income Tax Expense (Benefit) from Discontinued Operations:			
Current income taxes:			
Federal	$—	$—	$(25,528)
State	—	—	(10,418)
Deferred income taxes:			
Federal	—	—	(20,549)
Income tax expense from discontinued operations	$—	$—	$(56,495)
Total income tax expense	$103,344	$85,032	$2,355

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

	As of December 31,	
	2011	2010
	(In Thousands)	
Current deferred tax assets	$394	$30,248
Non-current deferred tax liabilities	1,110,463	1,102,625
Net deferred tax liabilities	$1,110,069	$1,072,377

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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,	
	2011	2010
	(In Thousands)	
Deferred tax assets:		
Deferred employee benefit costs	$202,687	$155,400
Business tax credit carryforward (a)	159,163	134,629
Net operating loss carryforward (b)	84,365	—
Deferred regulatory gain on sale-leaseback	42,962	45,381
Deferred state income taxes	42,209	14,215
Alternative minimum tax carryforward (c)	36,471	34,270
Deferred compensation	28,286	40,401
Accrued liabilities	16,912	35,714
Disallowed costs	12,717	13,357
Capital loss carryforward (d)	12,554	3,527
Other	13,031	33,577
Total gross deferred tax assets	651,357	510,471
Less: Valuation allowance (e)	13,712	59,415
Deferred tax assets	$637,645	$451,056
Deferred tax liabilities:		
Accelerated depreciation	$1,088,727	$920,229
Deferred employee benefit costs	202,687	161,035
Acquisition premium	187,934	195,947
Amounts due from customers for future income taxes, net	168,804	172,181
Deferred state income taxes	39,512	16,577
Debt reacquisition costs	21,683	23,864
Pension expense tracker	14,600	8,446
Storm costs	10,176	13,733
Other	13,591	11,421
Total deferred tax liabilities	$1,747,714	$1,523,433
Net deferred tax liabilities	$1,110,069	$1,072,377

(a) Based on filed tax returns and amounts expected to be reported in current year tax returns (December 31, 2011), we had available federal general business tax credits of $29.7 million and state investment tax credits of $129.5 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 2031. The state investment tax credits expire beginning in 2013 and ending in 2027. We believe these tax credits will be fully utilized prior to expiration.

(b) As of December 31, 2011, we had a federal net operating loss carryforward of $206.6 million, which is available to offset federal taxable income. The net operating losses will expire in 2030 and 2031.

(c) As of December 31, 2011, we had available an alternative minimum tax credit carryforward of $36.5 million, which has an unlimited carryforward period.

(d) As of December 31, 2011, we had an unused capital loss carryforward of $31.7 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 $12.5 million. In addition, we have established a valuation allowance of $1.2 million for certain deferred tax assets related to the write-down of other investments. The total valuation allowance related to the deferred tax assets was $13.7 million as of December 31, 2011, and $59.4 million as of December 31, 2010. The valuation allowance decreased $45.7 million in 2011 due to the reversal of a valuation allowance of $51.9 million that we had established against unused state investment tax credits. We reversed this valuation allowance because the state investment tax credits are now more likely than not to be realized due to a state law change which extended the state tax credit carryforward period from 10 to 16 years.

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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.

	For the Year Ended December 31,					
	2011		2010		2009	
Statutory federal income tax rate from continuing operations	35.0	%	35.0	%	35.0	%
Effect of:						
Corporate-owned life insurance policies	(4.5	)	(6.1	)	(8.2	)
State income taxes	4.1		3.8		4.3	
Production tax credits	(2.9	)	(3.4	)	(3.0	)
Accelerated depreciation flow through and amortization	1.8		2.6		3.7	
Amortization of federal investment tax credits	(0.8	)	(0.9	)	(1.4	)
AFUDC equity	(0.6	)	(0.4	)	(0.9	)
Capital loss utilization	(0.5	)	(0.7	)	(0.4	)
Liability for unrecognized income tax benefits	—		(0.2	)	0.2	
Other	(1.2	)	(0.7	)	0.1	
Effective income tax rate from continuing operations	30.4	%	29.0	%	29.4	%

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

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 November 2009, the IRS completed its examination of the federal income tax return and the amended federal income tax returns we filed for tax years 1999, 2005, 2006 and 2007. The examination resulted in a tax refund of $34.9 million. The examination results were approved by the Joint Committee on Taxation of the U.S. Congress and accepted by the IRS in April 2010.

In January 2009, we reached a settlement with the IRS for tax years 2003 and 2004 that included a determination of the amount of the net capital loss and net operating loss carryforwards available from the sale of a former subsidiary in 2004. This settlement resulted in our recording in 2009 a net earnings benefit from discontinued operations of approximately $33.7 million, net of $22.8 million paid to the former subsidiary under the sale agreement.

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The liability for unrecognized income tax benefits increased from $1.9 million at December 31, 2010, to $2.5 million at December 31, 2011. The net increase in the liability for unrecognized income tax benefits was largely attributable to tax positions taken with respect to the capitalization of plant related expenditures. We do not expect significant changes in the liability for unrecognized income tax benefits in the next 12 months. A reconciliation of the beginning and ending amounts of unrecognized income tax benefits is as follows:

	2011	2010	2009
	(In Thousands)		
Liability for unrecognized income tax benefits as of January 1	$1,888	$8,357	$38,980
Additions based on tax positions related to the current year	967	608	2,254
Additions for tax positions of prior years	939	2,323	—
Reductions for tax positions of prior years	(563)	(1,241)	(25,722)
Settlements	(748)	(8,159)	(7,155)
Liability for unrecognized income tax benefits as of December 31	$2,483	$1,888	$8,357

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 $0.2 million, $1.0 million and $23.7 million as of December 31, 2011, 2010, 2009, respectively. The amounts of unrecognized income tax benefits that, if recognized, would favorably impact our effective income tax rate, were $1.2 million, $1.3 million and $2.1 million (net of tax) as of December 31, 2011, 2010 and 2009, respectively.

Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. During 2011, 2010 and 2009, we reversed interest expense previously recorded for income tax uncertainties of $0.2 million, $1.0 million and $2.4 million, respectively. As of December 31, 2011 and 2010, we had $0.2 million and $0.4 million, respectively, accrued for interest on our liability related to unrecognized income tax benefits. We accrued no penalties at either December 31, 2011, or December 31, 2010.

As of December 31, 2011 and 2010, we had recorded $1.5 million and $3.6 million, respectively, 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.

We expect to fund our pension plan each year at least to a level equal to our 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.

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

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2011	2010	2011	2010
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$747,460	$662,495	$137,759	$128,998
Service cost	16,076	13,926	1,803	1,526
Interest cost	40,045	39,391	6,793	7,083
Plan participants' contributions	—	—	3,390	3,292
Benefits paid	(31,107)	(29,690)	(10,114)	(11,090)
Actuarial losses (gains)	94,161	60,662	5,246	7,950
Amendments	—	676	4,451	—
Other (a)	9,673	—	750	—
Benefit obligation, end of year	$876,308	$747,460	$150,078	$137,759
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$432,233	$404,243	$86,984	$74,114
Actual return on plan assets	27,819	33,359	(174)	9,849
Employer contributions	50,000	22,400	10,793	10,512
Plan participants' contributions	—	—	3,244	3,147
Part D reimbursements	—	—	—	317
Benefits paid	(28,975)	(27,769)	(9,739)	(10,955)
Other (a)	—	—	750	—
Fair value of plan assets, end of year	$481,077	$432,233	$91,858	$86,984
Funded status, end of year	$(395,231)	$(315,227)	$(58,220)	$(50,775)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$(2,741)	$(2,030)	$(115)	$(91)
Noncurrent liability	(392,490)	(313,197)	(58,105)	(50,684)
Net amount recognized	$(395,231)	$(315,227)	$(58,220)	$(50,775)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$397,691	$323,924	$18,178	$8,458
Prior service cost	4,606	5,819	18,991	17,065
Transition obligation	—	—	4,236	8,148
Net amount recognized	$402,297	$329,743	$41,405	$33,671

(a) 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.

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	Pension Benefits		Post-retirement Benefits	
As of December 31,	2011	2010	2011	2010
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$876,308	$747,460	$—	$—
Fair value of plan assets	481,077	432,233	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$750,263	$635,541	—	—
Fair value of plan assets	481,077	432,233	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	—	—	$150,078	$137,759
Fair value of plan assets	—	—	91,858	86,984
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	4.50 %	5.35 %	4.25 %	5.00 %
Compensation rate increase	4.00 %	4.00 %	—	—

We use a measurement date of December 31 for our pension and post-retirement benefit plans. In addition, we use an interest rate yield curve that is constructed based on the yields of over 500 high-quality, non-callable corporate bonds with maturities between zero and 30 years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of our pension plan and develop a single-point discount rate matching the plan's payout structure.

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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. Following is additional information regarding our pension and post-retirement benefit plans.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2011	2010	2009	2011	2010	2009
	(Dollars in Thousands)					
Components of Net Periodic Cost (Benefit):						
Service cost	$16,076	$13,926	$12,882	$1,803	$1,526	$1,529
Interest cost	40,045	39,391	38,162	6,793	7,083	6,917
Expected return on plan assets	(31,087)	(38,384)	(37,826)	(5,002)	(5,197)	(4,756)
Amortization of unrecognized:						
Transition obligation, net	—	—	—	3,911	3,912	3,912
Prior service costs	1,213	2,729	2,668	2,524	2,154	1,580
Actuarial loss/(gain), net	23,659	17,183	14,263	702	321	(38)
Net periodic cost before regulatory adjustment	49,906	34,845	30,149	10,731	9,799	9,144
Regulatory adjustment	(22,098)	(12,167)	(9,188)	1,344	1,868	2,280
Net periodic cost	$27,808	$22,678	$20,961	$12,075	$11,667	$11,424
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$97,429	$65,690	$(34,610)	$10,421	$3,298	$(26,205)
Amortization of actuarial (loss)/gain	(23,659)	(17,183)	(14,263)	(702)	(321)	38
Current year prior service cost	—	676	48	4,451	—	6,672
Amortization of prior service costs	(1,213)	(2,729)	(2,668)	(2,524)	(2,154)	(1,580)
Current year offset of initial transition asset due to plan change	—	—	—	—	—	(76)
Amortization of transition obligation	—	—	—	(3,911)	(3,912)	(3,912)
Total recognized in regulatory assets	$72,557	$46,454	$(51,493)	$7,735	$(3,089)	$(25,063)
Total recognized in net periodic cost and regulatory assets	$100,365	$69,132	$(30,532)	$19,810	$8,578	$(13,639)
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):						
Discount rate	5.35%	5.95%	6.10%	5.00%	5.65%	6.05%
Expected long-term return on plan assets	6.50%	8.25%	8.25%	6.00%	7.75%	7.75%
Compensation rate increase	4.00%	4.00%	4.00%	—	—	—

We estimate that we will amortize the following amounts from regulatory assets into net periodic cost in 2012.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$32,782	$1,509
Prior service cost	613	2,524
Transition obligation	—	3,911
Total	$33,395	$7,944

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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.

The Medicare Prescription Drug Improvement and Modernization Act of 2003 introduced a prescription drug benefit under Medicare as well as a federal subsidy that will be paid to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare. Prior to January 1, 2010, we believed that our retiree health care benefit plan was at least actuarially equivalent to Medicare and was, thus, eligible for the federal subsidy. However, due to plan changes effective January 1, 2010, we are no longer entitled to the federal subsidy. As a result, the subsidy did not have an effect on our accumulated post-retirement benefit obligation in 2011, 2010 or 2009, and did not impact our net period post-retirement benefit cost in 2011 or 2010. The subsidy decreased net periodic post-retirement benefit cost by approximately $1.9 million in 2009.

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

	As of December 31,	
	2011	2010
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	2018	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	$69	$(65)
Effect on post-retirement benefit obligation	1,465	(1,362)

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.

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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, we have established restrictions to reduce concentration of risk. For example, for domestic investments, no more than 5% of pension plan assets and 5% of post-retirement benefit plan assets should be invested in the securities of a single issuer, with the exception of the U.S. government and its agencies. In addition, the plans will neither acquire more than 10% of any one issuer nor invest more than 25% of their assets in any single industry. These restrictions do not apply to securities issued or guaranteed by the U.S. government or its agencies.

The target allocations for our pension plan assets are about 42% to equity securities, 44% to debt 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-state 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 $14.1 million as of December 31, 2011, invested directly in long-term U.S. Treasury securities. We also maintain certain level 3 investments in private equity, high-yield bonds, 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.

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The following table provides the fair value of our pension plan assets and the corresponding level of hierarchy as of December 31, 2011 and 2010.

As of December 31, 2011	Level 1 (In Thousands)	Level 2	Level 3	Total
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
As of December 31, 2010				
Assets:				
Domestic equity	$—	$117,250	$11,575	$128,825
International equity	—	44,834	—	44,834
Core bonds	—	183,361	—	183,361
High-yield bonds	—	28,819	1,200	30,019
Real estate securities	—	—	16,411	16,411
Alternative funds	—	—	25,764	25,764
Cash equivalents	—	3,019	—	3,019
Total Assets Measured at Fair Value	$—	$377,283	$54,950	$432,233

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, 2011 and 2010.

	Domestic Equity (In Thousands)	High-yield Bonds	Real Estate Securities	Alternative Funds	Net Balance
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
Balance as of December 31, 2009	$9,310	$22,519	$14,518	$—	$46,347
Actual gain (loss) on plan assets:					
Relating to assets still held at the reporting date	75	(3,963)	2,117	864	(907)
Relating to assets sold during the period	—	4,325	(77)	—	4,248
Purchases, issuances and settlements, net	2,190	(21,681)	(147)	24,900	5,262

Balance as of December 31, 2010	$11,575	$1,200	$16,411	$25,764	$54,950

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The following table provides the fair value of our post-retirement benefit plan assets and the corresponding level of hierarchy as of December 31, 2011 and 2010.

As of December 31, 2011	Level 1	Level 2	Level 3	Total
	(In Thousands)			
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
As of December 31, 2010				
Assets:				
Domestic equity	$—	$45,766	$—	$45,766
International equity	—	11,280	—	11,280
Core bonds	—	29,938	—	29,938
Total Assets Measured at Fair Value	$—	$86,984	$—	$86,984

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	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
	(In Millions)			
Expected contributions:				
2012	$57.4	$2.7	$10.8	$0.1
Expected benefit payments:				
2012	$(29.3)	$(2.7)	$(7.9)	$(0.1)
2013	(31.1)	(2.7)	(8.3)	(0.1)
2014	(33.1)	(2.8)	(8.7)	(0.1)
2015	(35.1)	(2.8)	(9.3)	(0.1)
2016	(37.8)	(2.8)	(9.6)	(0.1)
2017 - 2021	(231.9)	(13.2)	(51.3)	(0.7)

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 $7.0 million in 2011, $7.4 million in 2010 and $6.5 million in 2009.

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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. On May 19, 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, 2011, awards of approximately 4.5 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,		
	2011	2010	2009
	(In Thousands)		
Compensation expense	$8,367	$11,321	$5,080
Income tax benefits related to stock-based compensation arrangements	3,309	4,481	2,011

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 chief executive officer that were subject to forfeiture were modified to provide for the vesting upon his retirement on July 31, 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 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 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 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 the 2010 valuation, inputs for expected volatility and risk-free interest rates ranged from 25.2% to 30.1% and 0.3% to 1.4%, 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.

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During the years ended December 31, 2011, 2010 and 2009, our RSU activity for awards with only service requirements was as follows:

	As of December 31, 2011		2010		2009	
	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	600.4	$21.50	368.8	$21.98	727.4	$20.86
Granted	284.1	26.30	366.4	22.14	83.5	18.33
Vested	(187.3)	23.50	(118.1)	24.81	(439.0)	19.43
Forfeited	(328.7)	24.37	(16.7)	22.32	(3.1)	20.63
Nonvested balance, end of year	368.5	23.83	600.4	21.50	368.8	21.98

Total unrecognized compensation cost related to RSU awards with only service requirements was $4.2 million as of December 31, 2011. We expect to recognize these costs over a remaining weighted-average period of 1.9 years. The total fair value of RSUs with only service requirements that vested during the years ended December 31, 2011, 2010 and 2009, was $4.8 million, $2.7 million and $8.8 million, respectively.

During the years ended December 31, 2011, 2010 and 2009, our RSU activity for awards with performance measures was as follows:

	As of December 31, 2011		2010		2009	
	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	348.4	$24.98	—	$—	—	$—
Granted	244.4	31.26	366.0	24.96	—	—
Vested	(119.5)	24.12	(4.5)	23.32	—	—
Forfeited	(149.1)	28.72	(13.1)	24.99	—	—
Nonvested balance, end of year	324.2	28.31	348.4	24.98	—	—

Total unrecognized compensation cost related to RSU awards with performance measures was $3.3 million as of December 31, 2011. 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 year ended December 31, 2011 was $3.6 million. No performance RSUs vested in 2010 and 2009.

Previously, RSU awards that could be settled in cash upon a change in control were classified as temporary equity. However, all of these awards were forfeited in 2011. As of December 31, 2010, we had temporary equity of $3.5 million recorded on our consolidated balance sheet.

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.

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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 4,757 shares of common stock for dividends in 2011, 6,627 shares in 2010 and 7,106 shares in 2009. Participants received common stock distributions of 67,426 shares in 2011, 1,198 shares in 2010 and 563 shares in 2009.

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

12. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefit Plans

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

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As of December 31,	Pension Benefits 2011	2010	Post-retirement Benefits 2011	2010
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$131,460	$111,033	$10,144	$9,574
Service cost	4,957	4,144	165	179
Interest cost	7,370	6,941	458	519
Plan participants' contributions	—	—	614	554
Benefits paid	(3,033)	(2,799)	(979)	(1,045)
Actuarial losses (gains)	20,642	12,141	(360)	363
Other (a)	—	—	87	—
Benefit obligation, end of year	$161,396	$131,460	$10,129	$10,144
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$76,086	$62,516	$—	$—
Actual return on plan assets	(2,578)	10,082	—	—
Employer contributions	10,009	6,044	369	—
Plan participants' contribution	—	—	614	—
Benefits paid	(2,790)	(2,556)	(979)	—
Fair value of plan assets, end of year	$80,727	$76,086	$4	$—
Funded status, end of year	$(80,669)	$(55,374)	$(10,125)	$(10,144)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$(243)	$(256)	$(609)	$(689)
Noncurrent liability	(80,426)	(55,118)	(9,516)	(9,455)
Net amount recognized	$(80,669)	$(55,374)	$(10,125)	$(10,144)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$65,273	$39,735	$3,208	$3,796
Prior service cost	31	47	—	—
Transition obligation	—	52	58	115
Net amount recognized	$65,304	$39,834	$3,266	$3,911

As of December 31,	Pension Benefits 2011	2010	Post-retirement Benefits 2011	2010
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$161,396	$131,460	$—	$—
Fair value of plan assets	80,727	76,086	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$128,633	$106,684	$—	$—
Fair value of plan assets	80,727	76,086	—	—

Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:								
Accumulated post-retirement benefit obligation	$—		$—		$10,129		$10,144	
Fair value of plan assets	—		—		4		—	
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:								
Discount rate	4.55	%	5.45	%	4.10	%	4.90	%
Compensation rate increase	4.00	%	4.00	%	—		—	

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

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Wolf Creek uses a measurement date of December 31 for its pension and post-retirement benefit plans. In addition, Wolf Creek uses an interest rate yield curve that is constructed based on the yields on over 500 high-quality, non-callable corporate bonds with maturities between zero and 30 years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of Wolf Creek's pension plan and develop a single-point discount rate matching the plan's payout structure.

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,	2011	2010	2009	2011	2010	2009
	(Dollars in Thousands)					
Components of Net Periodic Cost (Benefit):						
Service cost	$4,957	$4,144	$3,643	$165	$179	$188
Interest cost	7,370	6,941	6,401	458	519	538
Expected return on plan assets	(5,904)	(5,453)	(4,976)	—	—	—
Amortization of unrecognized:						
Transition obligation, net	52	57	57	58	58	58
Prior service costs	16	29	43	—	—	—
Actuarial loss, net	3,586	2,636	2,538	227	276	257
Net periodic cost before regulatory adjustment	10,077	8,354	7,706	908	1,032	1,041
Regulatory adjustment	(2,546)	(1,498)	(945)	—	—	—
Net periodic cost	$7,531	$6,856	$6,761	$908	$1,032	$1,041
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$29,124	$7,514	$(3,407)	$(360)	$363	$708
Amortization of actuarial loss	(3,586)	(2,636)	(2,538)	(227)	(276)	(257)
Amortization of prior service cost	(16)	(29)	(43)	—	—	—
Amortization of transition obligation	(52)	(57)	(57)	(58)	(58)	(58)
Total recognized in regulatory assets	$25,470	$4,792	$(6,045)	$(645)	$29	$393
Total recognized in net periodic cost and regulatory assets	$33,001	$11,648	$716	$263	$1,061	$1,434
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:						
Discount rate	5.45%	6.05%	6.15%	4.90%	5.50%	6.05%
Expected long-term return on plan assets	7.50%	8.00%	8.00%	—	—	—
Compensation rate increase	4.00%	4.00%	4.00%	—	—	—

We estimate that we will amortize the following amounts from regulatory assets into net periodic cost in 2012.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$5,368	$233
Prior service cost	6	—
Transition obligation	—	58
Total	$5,374	$291

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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, 2011	2010
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	2018	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 (In Thousands)	One-Percentage-Point Decrease
Effect on total of service and interest cost	$(8)	$8
Effect on post-retirement benefit obligation	(107)	103

Plan Assets

The Wolf Creek pension plan investment strategy supports the objective of the trust, which is to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. Investments are diversified across classes, sectors and manager style to maximize returns and minimize the risk of large losses. Wolf Creek delegates investment management to specialists in each asset class and, where appropriate, provides the investment managers with specific guidelines, which include allowable and/or prohibited investment types. Prohibited investments include investments in the equity or debt securities of the companies that collectively own Wolf Creek or companies that control such companies, which includes our and KGE securities, except as may occur indirectly through investments in diversified mutual funds. Wolf Creek has also established restrictions for certain classes of plan assets including that international equity securities should not exceed 25% of total plan assets, no more than 5% of the market value of the plan assets should be invested in the common stock of one corporation and the equity investment in any one corporation should not exceed 1% of its outstanding common stock. Wolf Creek measures and monitors investment risk on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements. Wolf Creek post-retirement benefit plan assets are cash.

The target allocations for Wolf Creek's pension plan assets are 22% to international equity securities, 43% to domestic equity securities, 25% to debt securities, 5% to real estate securities and 5% to commodity 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.

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Wolf Creek's investments in equity, debt and commodity instruments are recorded at fair value using quoted market prices or valuation models utilizing observable market data when available. A portion of the investments is comprised of real estate securities that require significant unobservable market information to measure the fair value of the investments. Real estate securities 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.

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, 2011 and 2010.

As of December 31, 2011	Level 1	Level 2	Level 3	Total
	(In Thousands)			
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
As of December 31, 2010				
Assets:				
Domestic equity	$31,492	$—	$—	$31,492
International equity	9,036	9,597	—	18,633
Core bonds	—	14,156	—	14,156
High-yield bonds	3,319	—	—	3,319
Real estate securities	—	—	3,160	3,160
Commodities	—	4,558	—	4,558
Cash equivalents	1	767	—	768
Total Assets Measured at Fair Value	$43,848	$29,078	$3,160	$76,086

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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, 2011 and 2010.

	Real Estate Securities (In Thousands)
Balance as of December 31, 2010	$3,160
Actual gain (loss) on plan assets:	
Relating to assets still held at the reporting date	500
Relating to assets sold during the period	2
Purchases, issuances and settlements, net	(32)
Balance as of December 31, 2011	$3,630
Balance as of December 31, 2009	$2,416
Actual gain (loss) on plan assets:	
Relating to assets still held at the reporting date	393
Relating to assets sold during the period	(2)
Purchases, issuances and settlements, net	353
Balance as of December 31, 2010	$3,160

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	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
	(In Millions)			
Expected contributions:				
2012	$11.5	$0.2	$—	$0.6
Expected benefit payments:				
2012	$(3.4)	$(0.2)	$—	$(0.6)
2013	(3.9)	(0.2)	—	(0.7)
2014	(4.4)	(0.2)	—	(0.7)
2015	(5.1)	(0.2)	—	(0.7)
2016	(5.9)	(0.2)	—	(0.8)
2017 - 2021	(43.3)	(1.0)	—	(4.0)

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 2011, $1.1 million in 2010 and $1.1 million in 2009.

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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, which is discussed below under "- Purchased Power and Fuel Commitments," that had an unexpended balance of approximately $560.6 million as of December 31, 2011, of which $410.8 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, 2011, was as follows.

	Committed Amount (In Thousands)
2012	$263,076
2013	72,121
2014	54,113
Thereafter	21,491
Total amount committed	$410,801

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 pollutants generated from our operations, including sulfur dioxide (SO_2), particulate matter (PM), nitrogen oxides (NOx), carbon monoxide (CO) and mercury.

Emissions from our generating facilities, including PM, SO_2 and NOx, have been determined by regulation to reduce visibility by causing or contributing to regional haze. Under federal laws, such as the Clean Air Visibility Rule, and pursuant to an agreement with the Kansas Department of Health and Environment (KDHE) and Environmental Protection Agency (EPA), we are required to install 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 six criteria pollutants considered harmful to public health and the environment, including PM, NOx, CO and SO_2, which result from coal combustion. Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS. NAAQS must be reviewed by the EPA at five-year intervals. In 2009, KDHE proposed to designate portions of the Kansas City area nonattainment for the 8-hour ozone standard, which has the potential to impact our operations.

In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. We 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 interpretation of 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.

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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. As previously discussed, we are not allowed to use the ECRR to collect our approximately $600.0 million share of the costs associated with the $1.2 billion of environmental upgrades at La Cygne. We must file for a general review of our rates or an abbreviated rate review with the KCC in order to collect these costs. In order 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 PM, mercury and other air toxics. In December 2011, the EPA finalized Mercury and Air Toxics Standards for power plants, which replaces the prior federal Clean Air Mercury Rule and requires significant reductions in emissions of mercury and other air toxics. Companies impacted by the new standards will have up to four years, and in certain limited circumstances up to five years, to comply. We are currently evaluating the new standards and cannot at this time determine the impact they may have on our operations and consolidated financial results, but we believe the cost of compliance could be material.

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) which requires 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 scheduled to begin January 1, 2012, with further reductions required beginning January 1, 2014. The EPA issued federal implementation plans for each state covered by CSAPR, but would allow these states to submit their own implementation plans starting as early as 2013. In October 2011, we filed legal challenges to CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit.

In December 2011, the EPA published a final supplemental rule to CSAPR requiring five states to make summertime reductions in NOx emissions under an ozone-season control program implemented under CSAPR. Reductions in ozone-season NOx under this rule were scheduled to begin May 1, 2012. Although Kansas was included in the original proposed rules, the final supplemental rule instead calls for the EPA to revisit Kansas' status under this supplemental rule once Kansas submits an ozone state implementation plan, which must occur within 12 to 18 months from the date the EPA issues a state implementation call to Kansas. The EPA has not yet issued such a call.

On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued its ruling to stay CSAPR, including the final supplemental rule, pending judicial review, which delays CSAPR's implementation date beyond January 1, 2012. The court is scheduled to hear the cases starting in April 2012. Under this timeframe, the court could issue its decision by summer or early fall 2012. As the outcome of the judicial review and any other possible legal or Congressional challenges are uncertain, we are unable to determine what impact CSAPR may ultimately have on our operations and consolidated financial results, but it could be material.

Greenhouse Gases

Under EPA regulations finalized in May 2010, 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: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications, which is referred to as the Prevention of Significant Deterioration program (PSD). Obligations relating to Title V permits include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors), are required to implement best available control technology (BACT). 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 new regulations on our operations and consolidated financial results, but we believe the cost of compliance with new regulations could be material.

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Renewable Energy Standard

Kansas law mandates that our capacity consists of a certain amount of renewable sources. In years 2011 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. We met the 2011 requirement using our existing approximately 300 MW of qualifying wind generation facilities along with renewable energy credits. Beginning in late 2012, we will purchase under 20-year supply contracts the renewable energy produced from an additional approximately 370 MW of wind generation, which 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.

Manufactured Gas Sites

We have been identified as being partially responsible for remediating a number of former manufactured gas sites located in Kansas. We and KDHE entered into a consent agreement governing all future work at these sites. Under terms of the consent agreement, we agreed to investigate and, if necessary, remediate these sites. Pursuant to an environmental indemnity agreement, ONEOK Inc. (ONEOK) assumed total liability for remediation of seven sites and we share liability for remediation with ONEOK for five sites. Our total liability for the five shared sites is capped at $3.8 million and terminates in November 2012.

Our environmental liability for remediation of former manufactured gas sites in Missouri associated with assets we divested many years ago had been limited to $7.5 million by the terms of an environmental indemnity agreement with the purchaser of those assets. In June 2010, the purchaser agreed to reduce our liability to $2.5 million, which reflects our share of the purchaser's expected remediation costs. We settled this liability in 2010.

EPA Lawsuit

In 2010, we settled a lawsuit filed by the Department of Justice on behalf of the EPA. We agreed to certain initial requirements as part of the settlement and also agreed to take further steps contingent on the outcome of the effectiveness of the initial requirements. As part of the initial requirements, we will install a selective catalytic reduction (SCR) on one of three JEC coal units by the end of 2014, which we estimate will cost approximately $240.0 million. Depending on the NOx emission reductions attained by the single SCR and attainable through the installation of other controls on the other two JEC coal units, we may have to install an SCR on another JEC unit by the end of 2016, if needed to meet plant-wide NOx reduction targets. We plan to recover the costs to install these systems through our ECRR, but such recovery remains subject to the approval of our regulators.

FERC Investigation

A non-public investigation by FERC of our use of transmission service between July 2006 and February 2008 remains pending. 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. FERC staff first alleged we received $14.3 million of unjust profits through such activities. We sent a response to FERC staff disputing both the legal basis for its allegations and their factual underpinnings. Based on our response, FERC staff substantially revised downward its preliminary conclusions to allege that we received $3.0 million of unjust profits and failed to pay $3.2 million to the SPP for transmission service. In March 2010, we sent a response to FERC staff disputing its revised conclusions. Following additional communications with FERC staff, FERC staff further revised its preliminary conclusions to allege that we have received $0.9 million of unjust profits and failed to pay $0.8 million to the SPP for transmission service. Although we continue to believe our use of transmission service was in compliance with FERC orders and SPP tariffs, we recorded an estimated liability of $0.5 million as of December 31, 2011, related to the potential settlement of this investigation and the risks of litigating this matter to a final outcome. We are unable to predict the outcome of this investigation or its impact on our consolidated financial results, but an adverse outcome could result in payments for alleged unjust profits and unpaid transmission costs as well as penalties, the amounts of which could be material, and could potentially alter the manner in which we are permitted to buy and sell energy and use transmission service.

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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 2011, $3.1 million in 2010 and $2.9 million in 2009. We record our investment in the NDT fund at fair value, which approximated $130.3 million and $127.0 million as of December 31, 2011 and 2010, 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 $3.1 million in 2011, $4.0 million in 2010 and $3.7 million in 2009. 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. Oral argument to the court is expected in 2012. 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 store 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.

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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 scheduled 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, we may be subject to retrospective assessments under the current policies of approximately $30.9 million (our share is $14.5 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 and Purchased Power 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, 2011, our share of Wolf Creek's nuclear fuel commitments was approximately $38.4 million for uranium concentrates expiring in 2017, $5.8 million for conversion expiring in 2017, $116.1 million for enrichment expiring in 2024 and $43.0 million for fabrication expiring in 2024.

As of December 31, 2011, our coal and coal transportation contract commitments in 2011 dollars under the remaining terms of the contracts were approximately $886.0 million. The contracts are for plants that we operate and expire at various times through 2021.

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As of December 31, 2011, our natural gas transportation contract commitments in 2011 dollars under the remaining terms of the contracts were approximately $145.9 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 two separate wind generation facilities with installed design capacities of 146 MW. The agreements expire in late 2028 and early 2029. In addition, we have entered into two separate agreements with third parties to purchase under 20-year supply contracts the renewable energy produced from approximately 370 MW of wind generation beginning in late 2012. Each of the aforementioned 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 $31.7 million in 2012 and $68.2 million beginning in 2013.

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,	
	2011	2010
	(In Thousands)	
Beginning ARO	$125,999	$119,519
Liabilities incurred	—	—
Liabilities settled	(1,027)	(738)
Accretion expense	7,623	7,218
Increase in nuclear decommissioning ARO liability	9,913	—
Ending ARO	$142,508	$125,999

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 ash landfills retirement obligation 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.

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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, 2011 and 2010, we had $82.3 million and $70.3 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability.

15. LEGAL PROCEEDINGS

In late 2002, one of our former executive officers resigned from his position and another executive officer was placed on administrative leave from his position. Following the completion of an investigation and the publication of a report prepared by a special committee of our board of directors, our board of directors determined that their employment was terminated for cause. In June 2003, we filed a demand for arbitration with the American Arbitration Association asserting claims against them arising out of their previous employment and seeking to avoid payment of compensation not yet paid to them under various plans and agreements. They filed counterclaims against us alleging substantial damages related to the termination of their employment and the publication of the report of the special committee. The arbitration was stayed in August 2004 pending final resolution of criminal charges filed against them in U.S. District Court in the District of Kansas. In August 2010, these criminal charges were dismissed and subsequently the stay of the arbitration was lifted. As of December 31, 2010, we had accrued liabilities of $80.6 million for compensation not yet paid to the former executive officers and $8.3 million for legal fees and expenses they had incurred. In May 2011, we reached an agreement with Douglas T. Lake, one of the former executive officers, settling all contractual obligations. Pursuant to the agreement, we paid him approximately $21.0 million and we paid approximately $5.3 million for his legal fees and expenses. In July 2011, we reached an agreement with David C. Wittig, the other former executive officer, settling all contractual obligations and providing for payments totaling approximately $36.0 million, the release of deferred stock for compensation shares and the payment of $3.1 million for his legal fees and expenses. In the third quarter of 2011, we reversed the remaining approximately $22.0 million of previously accrued liabilities, 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 affect 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

On May 19, 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, 2011 and 2010, Westar Energy had issued and outstanding 125.7 million shares and 112.1 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 2011, 2010 and 2009, Westar Energy issued 0.8 million shares, 0.7 million shares and 0.8 million shares, respectively, through the DSPP and other stock-based plans operated under the LTISA Plan. As of December 31, 2011 and 2010, a total of 2.0 million shares and 2.6 million shares, respectively, were available under the DSPP registration statement.

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Issuances

In November 2010, Westar Energy entered into a 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, which increased the total number of shares under the forward sale agreement to approximately 8.5 million shares. The underwriters receive a commission equal to 3.5% of the sales price of all shares sold under the agreement. Westar Energy agreed to settle the forward sale agreement within 18 months of the transaction date. On November 17, 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.

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 one year of the date each transaction is entered. Westar Energy has entered into forward sale transactions with respect to an aggregate of approximately 5.4 million shares of common stock. In late 2010, Westar Energy delivered approximately 1.2 million shares of common stock for proceeds of $26.4 million as partial settlement of the forward sale transactions. Westar Energy delivered approximately 4.2 million shares of common stock in 2011 for proceeds of $91.9 million as complete settlement of this forward sale agreement.

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

Preferred Stock Not Subject to Mandatory Redemption

Westar Energy's cumulative preferred stock is redeemable in whole or in part on 30 to 60 days' notice at our option. The table below shows the redemption amounts for all series of our preferred stock not subject to mandatory redemption as of December 31, 2011.

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

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The provisions of Westar Energy's articles of incorporation, as amended, contain restrictions on the payment of dividends or the making of other distributions on its common stock while any preferred shares remain outstanding unless certain capitalization ratios and other conditions are met. If the ratio of the capital represented by Westar Energy's common stock, including premiums on its capital stock and its surplus accounts, to its total capital and its surplus accounts at the end of the second month immediately preceding the date of the proposed payment of dividends, adjusted to reflect the proposed payment (capitalization ratio), will be less than 20%, then the payment of the dividends on its common stock, including the proposed payment, during the 12-month period ending with and including the date of the proposed payment shall not exceed 50% of its net income available for dividends for the 12-month period ending with and including the second month immediately preceding the date of the proposed payment. If the capitalization ratio is 20% or more but less than 25%, then the payment of dividends on its common stock, including the proposed payment, during the 12-month period ending with and including the date of the proposed payment shall not exceed 75% of its net income available for dividends for the 12-month period ending with and including the second month immediately preceding the date of the proposed payment. Except to the extent permitted above, no payment or other distribution may be made that would reduce the capitalization ratio to less than 25%. The capitalization ratio is determined based on the unconsolidated balance sheet for Westar Energy. As of December 31, 2011, the capitalization ratio was greater than 25%.

So long as there are any outstanding shares of Westar Energy preferred stock, Westar Energy shall not without the consent of a majority of the shares of preferred stock or if more than one-third of the outstanding shares of preferred stock vote negatively and without the consent of a percentage of any and all classes required by law and Westar Energy's articles of incorporation, declare or pay any dividends (other than stock dividends or dividends applied by the recipient to the purchase of additional shares) or make any other distribution upon common stock unless, immediately after such distribution or payment the sum of Westar Energy's capital represented by its outstanding common stock and its earned and any capital surplus shall not be less than $10.5 million plus an amount equal to twice the annual dividend requirement on all the then outstanding shares of preferred stock.

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 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.

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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,	
	2011	2010
	(In Thousands)	
Assets:		
Property, plant and equipment of variable interest entities, net	$333,494	$345,037
Regulatory assets (a)	4,915	3,963
Liabilities:		
Current maturities of long-term debt of variable interest entities	$28,114	$30,155
Accrued interest (b)	4,448	5,064
Long-term debt of variable interest entities, net	249,283	278,162

(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 reported 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.

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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:	
2009	$38,096
2010 (a)	15,464
2011	17,577
Future commitments:	
2012	$16,247
2013	13,919
2014	11,820
2015	9,721
2016	8,393
Thereafter	17,520
Total future commitments	$77,620

(a) In 2010, we began consolidating certain trusts that hold assets we lease as VIEs as discussed in Note 17, "Variable Interest Entities." This eliminated the lease accounting we previously reported for these assets and, as a result, rental expense decreased significantly from 2009 to 2010.

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 four to five years.

On April 28, 2011, FERC issued an order approving a power supply agreement. The agreement extend through May 2039, the terms of which meet the criteria such that it is classified as a capital lease. Accordingly, we recorded a $40.0 million capital lease during the second quarter of 2011.

Assets recorded under capital leases are listed below.

	As of December 31,	
	2011	2010
	(In Thousands)	
Vehicles	$14,241	$12,504
Computer equipment	1,720	5,551

Power plant	40,048	—
Accumulated amortization	(6,485)	(8,744)
Total capital leases	$49,524	$9,311

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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)
2012	$5,452
2013	5,200
2014	5,203
2015	4,987
2016	4,127
Thereafter	67,830
	92,799
Amounts representing imputed interest	(43,275)
Present value of net minimum lease payments under capital leases	49,524
Less: Current portion	2,471
Total long-term obligation under capital leases	$47,053

19. DISCONTINUED OPERATIONS — Sale of Protection One, Inc.

In 2009, the Joint Committee on Taxation of the U.S. Congress approved a settlement with the IRS Office of Appeals regarding the re-characterization of a portion of the loss we incurred on the sale of Protection One, Inc. (Protection One), a former subsidiary, from a capital loss to an ordinary loss. The settlement involved a determination of the amount of the net capital loss and net operating loss carryforwards available as of December 31, 2004, to offset income in years after 2004. In 2009, we filed amended federal income tax returns for tax years 2005, 2006 and 2007 to claim a portion of the income tax benefits from the net operating loss carryforward. We expect to realize the remainder of the income tax benefits from the net operating loss carryforward in future years. We recorded a non-cash net earnings benefit of approximately $33.7 million, net of $22.8 million we paid Protection One, in discontinued operations in 2009 in recognition of this settlement.

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20. 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.

2011	First	Second	Third (a)	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues (b)	$481,720	$524,892	$678,152	$486,228
Net income (b)	32,957	45,525	136,392	21,306
Net income attributable to common stock (b)	31,342	43,887	134,708	19,335
Per Share Data (b):				
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) During the third quarter of 2011, we reversed $22.0 million of previously accrued liabilities as a result of the legal settlements discussed in Note 15,"Legal Proceedings," and recorded a $7.2 million gain on the sale of a non-utility investment. These two factors were the primary drivers for the increases in net income and net income attributable to common stock as compared to the third quarter of 2010.

(b) 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.

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2010	First	Second	Third (a)	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues (b)	$459,830	$495,181	$644,437	$456,723
Net income (b)	31,682	54,530	115,863	6,550
Net income attributable to common stock (b)	30,438	53,069	114,502	4,919
Per Share Data (b):				
Basic:				
Earnings available	$0.27	$0.47	$1.02	$0.04
Diluted:				
Earnings available	$0.27	$0.47	$1.01	$0.04
Cash dividend declared per common share	$0.31	$0.31	$0.31	$0.31
Market price per common share:				
High	$22.78	$23.93	$24.64	$25.90
Low	$20.56	$21.08	$21.22	$24.21

(a) In the third quarter of 2010, net income and net income attributable to common stock increased due principally to warmer than normal weather in our service territory. As measured by cooling degree days, the weather during the third quarter of 2010 was 20% warmer than the 20-year average.

(b) 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.

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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, 2011, 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

On February 20, 2012, we filed with the Secretary of State of the State of Kansas a certificate, the purpose of which was to amend our Restated Articles of Incorporation to eliminate reference to four series of our Preference Stock, shares of which series are no longer outstanding. Upon the effectiveness of the certificate, all shares of each such series became authorized but unissued shares of Preference Stock available for issuance. The certificate is attached hereto as Exhibit 3(n) and is incorporated into this Item 9B by this reference.

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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 2012 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (2012 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 2012 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 2012 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 2012 Proxy Statement under the captions "Compensation Discussion and Analysis," "Compensation Committee Report," "Compensation of Executive Officers," "Director Compensation" and "Compensation Committee Interlocks and Insider Participation," and that information is incorporated by reference in this Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 will be set forth in our 2012 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 2012 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 2012 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.

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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, 2011 and 2010
Consolidated Statements of Income for the years ended December 31, 2011, 2010 and 2009
Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009
Consolidated Statements of Changes in Equity for the years ended December 31, 2011, 2010 and 2009
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

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	#

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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

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

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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 Wards 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
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	#

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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, 2009				
Allowances deducted from assets for doubtful accounts	$4,810	$5,797	$(5,376)	$5,231
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

(a) Result from write-offs of accounts receivable.

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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 23, 2012

By: /s/ Anthony D. Somma
Anthony D. Somma
Senior Vice President, Chief Financial Officer and Treasurer

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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 23, 2012
/S/ ANTHONY D. SOMMA (Anthony D. Somma)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	February 23, 2012
/S/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 23, 2012
/S/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 23, 2012
/S/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 23, 2012
/S/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 23, 2012
/S/ RICHARD L. HAWLEY (Richard L. Hawley)	Director	February 23, 2012
/S/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 23, 2012
/S/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	February 23, 2012
/S/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 23, 2012
/S/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	February 23, 2012
/S/ S. CARL SODERSTROM JR. (S. Carl Soderstrom Jr.)	Director	February 23, 2012