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, 2009

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 ___ 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 $2,040,718,228 at

June 30, 2009.

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 (Class)	110,426,540 shares (Outstanding at February 17, 2010)

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 2009 Annual Meeting of Shareholders	Part III (Item 10 through Item 14) (Portions of Item 10 are not incorporated by reference and are provided herein)

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GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AFUDC	Allowance for Funds Used During Construction
ARO	Asset retirement obligation
BNSF	Burlington Northern Santa Fe
Btu	British Thermal Units
CO_2	Carbon Dioxide
Codification	FASB Accounting Standards Codification
COLI	Corporate-owned Life Insurance
DOE	Department of Energy
DOJ	Department of Justice
DSPP	Direct Stock Purchase Plan
ECRR	Environmental Cost Recovery Rider
EPA	Environmental Protection Agency
EPS	Earnings per share
ERISA	Employee Retirement Income Security Act
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Investors Service
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gas
INPO	Institute of Nuclear Power Operations
IRS	Internal Revenue Service
KCC	Kansas Corporation Commission
KCPL	Kansas City Power & Light Company
KDHE	Kansas Department of Health and Environment
KEPCo	Kansas Electric Power Cooperative, Inc.
KGE	Kansas Gas and Electric Company
kV	Kilovolt
La Cygne	La Cygne Generating Station
Lehman Brothers	Lehman Brothers Commercial Paper, Inc.
LTISA Plan	Long-Term Incentive and Share Award Plan
Medicare Act	Medicare Prescription Drug Improvement and Modernization Act of 2003
MMBtu	Millions of Btu
Moody's	Moody's Investors Service
MW	Megawatt(s)
MWh	Megawatt hour(s)
NEIL	Nuclear Electric Insurance Limited
NOx	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
ONEOK	ONEOK, Inc.
OTC	Over-the-counter
PCB	Polychlorinated Biphenyl
PRB	Powder River Basin
Protection One	Protection One, Inc.
RECA	Retail Energy Cost Adjustment
RSU	Restricted Share Unit

RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Group
SCR	Selective catalytic reduction
SEC	Securities and Exchange Commission
SPP	Southwest Power Pool
SSCGP	Southern Star Central Gas Pipeline
SO_2	Sulfur Dioxide
VaR	Value-at-Risk
VIE	Variable interest entity
WCNOC	Wolf Creek Nuclear Operating Corporation
Wolf Creek	Wolf Creek Generating Station

FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Annual Report on Form 10-K are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we "believe," "anticipate," "target," "expect," "pro forma," "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,
- unusual 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, 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 of or introduction of competition into markets in which we operate,
- 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,
- uncertainty regarding the establishment of interim or permanent sites for spent nuclear fuel storage and disposal,
- homeland and information security considerations,
- wholesale electricity prices,
- 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 climate impacts and development of alternate energy sources,
- current and future litigation, regulatory investigations, proceedings or inquiries,
- other circumstances affecting anticipated operations, sales and costs, and
- other factors discussed elsewhere in this report, including in "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and in other reports we file from time to time with the Securities and Exchange Commission (SEC).

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

PART I

ITEM 1. BUSINESS

GENERAL

Overview

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

We provide electric generation, transmission and distribution services to approximately 685,000 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. KGE owns a 47% interest in Wolf Creek, a nuclear power plant located near Burlington, Kansas. 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

Our strategy is to remain a vertically integrated electric utility meeting the energy needs of our customers reliably at reasonable prices. We strive to optimize flexibility in our planning and operations to be able to respond quickly to the uncertain and changing energy and environmental policies, economic conditions, regulations and technologies currently affecting or related to our business. Working constructively with our regulators and public officials is an important part of our strategy.

Significant elements of our strategy include environmental upgrades to our coal-fired power plants, the ability to use more natural gas-fired generation, the development of wind generation and the building and upgrading of transmission facilities. We also plan to invest significant resources to enhance our distribution system and to develop energy efficiency programs. Following is a summary of some of the progress we have made on these significant elements.

- During 2009, we made capital expenditures of $85.2 million at our power plants for air emission controls.
- We completed construction of the Emporia Energy Center, a natural gas-fired peaking power plant comprising approximately 660 megawatts (MW) of capacity, in early 2009 for a total investment of $304.5 million.
- Along with third parties, we developed approximately 300 MW of wind generation facilities at three different sites in Kansas, approximately half of which we own and half of which we purchase under long-term supply contracts. These wind generation facilities began producing energy in late 2008 and early 2009.
- We continued constructing a 345 kilovolt (kV) transmission line in central Kansas.
- We are actively engaged in numerous programs to enable and educate customers to use energy more efficiently.

Our plans and expectations for 2010 and beyond include:

- The potential to invest an additional $946.0 million of capital expenditures at our power plants for air emissions projects over the next three years.
- In January 2010, we reached an agreement with a third party to acquire the development rights for a site we believe is capable of supporting up to 500 MW of wind generation. We expect to develop the site in phases with the initial phase potentially completed by the end of 2012, subject to regulatory approvals and the pace of development of new transmission facilities in western Kansas.

- We expect to complete in 2010 the 345 kV transmission line we are constructing in central Kansas.
- In 2010, we expect to begin planning and engineering a 345 kV transmission line that will run from a location near Wichita, Kansas, south to the Kansas-Oklahoma border.
- Upon approval from the Southwest Power Pool (SPP) Board of Directors and appropriate regional cost allocation, Prairie Wind Transmission, LLC, a joint venture company of which we own 50%, intends to construct a new substation near Wichita, Kansas, and one near Medicine Lodge, Kansas, as well as a transmission line connecting the two substations. Prairie Wind also plans to construct a transmission line south to the Kansas-Oklahoma border from one of the two substations.
- We expect to continue improving our distribution system through enhanced vegetation management as well as equipment and process improvements.
- We expect to continue developing programs to better educate our customers about the efficient use of energy. One project we expect to undertake beginning in 2010 is SmartStar Lawrence, a smart grid project based in Lawrence, Kansas. Under this project, we will install Advanced Metering Infrastructure meters and other equipment to give customers the ability to better monitor their energy use. We applied for and have been selected by the Department of Energy (DOE) to negotiate a matching grant of approximately $19.0 million. We expect the total project cost to be approximately $39.3 million.

SIGNIFICANT BUSINESS DEVELOPMENTS

Weather

Our electricity sales and revenues are significantly impacted by the weather, mostly in the summer, and particularly during the third quarter. Warmer summer weather results in more demand for electricity while cooler summer weather reduces demand, especially among our residential customers. The opposite is true for the winter season, although to a lesser extent. The weather in our service territory during the third quarter of 2009 was the coolest in over 40 years. As measured by cooling degree days, the weather during this period was 14% cooler than the same period in 2008 and 27% cooler than the 20-year average.

Economic Conditions

Despite improvements in the capital markets and increases in asset valuations, many aspects of the downturn in the global and U.S. economy continued to impact our business throughout 2009. Most notably, many of our industrial customers continued to experience reduced production. This resulted in decreased demand for electricity from these customers as evidenced by the 10.8% decrease in industrial sales from 2008 to 2009. Additionally, the Kansas unemployment rate increased from 5.0% in December 2008 to 7.5% in July 2009 before declining to 6.6% in December 2009. We cannot predict when these economic conditions may improve or to what extent they may continue to affect electricity sales, including effects that may spill over into residential and commercial sales, and the affect this might have on our consolidated financial results.

Changes in Prices

On January 27, 2010, the Kansas Corporation Commission (KCC) issued an order allowing us to adjust our prices to include costs associated with our investments in natural gas and wind generation facilities that were not included in the price increase approved by the KCC in its January 21, 2009, order discussed below. The new prices were effective February 2010 and are expected to increase our annual retail revenues by $17.1 million.

On January 21, 2009, the KCC issued an order expected to increase our annual retail prices by $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 became effective on February 3, 2009.

The KCC and Federal Energy Regulatory Commission (FERC) also adjust our prices through the use of price methods that are designed to track certain portions of the costs of providing utility service. For additional information, see Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation."

Tax Settlement

In January 2009, we reached a settlement with the Internal Revenue Service (IRS) for years 2003 and 2004 associated with the re-characterization of a portion of the loss we incurred on the sale of Protection One, Inc. (Protection One) from a capital loss to an ordinary loss. This settlement resulted in a 2009 net earnings benefit from discontinued operations of $33.7 million, or $0.30 per share, net of $22.8 million we paid Protection One.

OPERATIONS

General

Westar Energy supplies electric energy at retail to approximately 368,000 customers in central and northeast Kansas and KGE supplies electric energy at retail to approximately 317,000 customers in south-central and southeastern Kansas. We also supply electric energy at wholesale to the electric distribution systems of 31 cities in Kansas and four electric cooperatives in Kansas. We also 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 our retail service territory.

We have a retail energy cost adjustment (RECA) under which we are permitted to recover in our prices the cost of fuel consumed in generating electricity and purchased power needed to serve our retail customers. Through the RECA, we bill our customers for fuel and purchased power costs based on a quarter-ahead estimate. The RECA provides for an annual review by the KCC to reconcile estimated and actual fuel and purchased power costs. The KCC uses this same method as the means by which we refund to customers the margins we realize from market-based wholesale sales.

Generation Capacity

We have 6,807 MW of accredited generating capacity in service, of which 2,586 MW is owned or leased by KGE. See "Item 2. Properties" for additional information on our generating units. While we also own 149 MW of wind generation facilities, the intermittent nature of this type of production does not create any appreciable amount of accredited capacity. The capacity by fuel type is summarized below.

Fuel Type	Capacity (MW)	Percent of Total Capacity
Coal	3,431	50%
Nuclear	545	8
Natural gas or oil	2,763	41
Diesel	68	1
Total	6,807	100%

In addition to owning and leasing generating capacity, we also have two purchase power agreements under which we purchase 146 MW of wind generation from third parties.

Our aggregate 2009 peak system net load of 4,545 MW occurred on June 23, 2009. This included 132 MW of potentially interruptible load. Our net generating capacity, combined with firm capacity purchases and sales and the ability to interrupt 132 MW of load, provided a capacity margin of 26.0% above system peak responsibility at the time of our 2009 peak system net load.

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

Utility (a)	Capacity (MW)	Period Ending
Midwest Energy, Inc. (b).	125	May 2010
Empire District Electric Company (c)	162	May 2010
Midwest Energy, Inc.	130	October 2013
Oklahoma Municipal Power Authority	61	December 2013
ONEOK Energy Services Co.	75	December 2015
Mid-Kansas Electric Company, LLC	175	January 2019
Kansas Power Pool	50	January 2020
Kansas Electric Power Cooperative, Inc. (d)	182	December 2045
Total	960	

(a) Under a wholesale agreement that expires in May 2027, we provide base load capacity to the city of McPherson, Kansas, and McPherson provides peaking capacity to us. During 2009, we provided approximately 84 MW to, and received approximately 151 MW from, McPherson. The amount of base load capacity provided to McPherson is based on a fixed percentage of McPherson's annual peak system load.
(b) We plan to enter into a new wholesale agreement with Midwest Energy, Inc. upon expiration of this agreement.
(c) We are uncertain about future plans regarding a new agreement with Empire District Electric Company.
(d) We provide power to Kansas Electric Power Cooperative, Inc. (KEPCo) based on its load. The amount provided can fluctuate from year to year as KEPCo's load changes. The amount provided in the table represents the actual MW provided during 2009.

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 less fuel it takes to produce electricity. We measure the quantity of heat consumed during the generation of electricity in millions of Btu (MMBtu).

Based on MMBtu, our 2009 fuel mix was 78% coal, 14% nuclear and 7% natural gas, with diesel and oil making up less than 1%. In 2010 we expect to use a higher percentage of nuclear fuel because Wolf Creek will not have a scheduled refueling and maintenance outage. Wolf Creek had such an outage in the fall of 2009. Additionally, 2009 was the first year our new wind generation facilities produced a significant amount of wind energy as discussed under "—Wind Generation" below. Our generation mix fluctuates with the operation of Wolf Creek, fluctuations 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: The three coal-fired units at Jeffrey Energy Center have an aggregate capacity of 2,164 MW, of which we own and lease a combined 92% share, or 1,991 MW. We have a long-term coal supply contract with Foundation Coal West to supply coal to Jeffrey Energy Center 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 Jeffrey Energy Center is purchased under this contract. The contract 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 then current market prices. The next re-pricing for those quantities over the scheduled annual minimum will occur in 2013.

The Burlington Northern Santa Fe (BNSF) and Union Pacific railroads transport coal for Jeffrey Energy Center from Wyoming 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 Jeffrey Energy Center during 2009 was approximately $1.59 per MMBtu, or $26.37 per ton.

La Cygne Generating Station: The two coal-fired units at La Cygne Generating Station (La Cygne) have an aggregate generating capacity of 1,418 MW, of which we own or lease a 50% share, or 709 MW. La Cygne unit 1 uses a blended fuel mix containing approximately 90% PRB coal and 10% Kansas/Missouri coal, the latter of which is purchased from time to time from Kansas and Missouri producers. La Cygne unit 2 uses PRB coal. The operator of La Cygne, Kansas City Power & Light Company (KCPL), arranges coal purchases and transportation services for La Cygne. All of the La Cygne unit 1 and unit 2 PRB coal is supplied through fixed price contracts through 2010 and is transported under KCPL's Omnibus Rail Transportation Agreement with the BNSF and Kansas City Southern Railroad through 2010. As the PRB coal contracts expire, we anticipate that KCPL will negotiate new supply contracts or purchase coal on the spot market.

During 2009, the average delivered cost of coal consumed at La Cygne unit 1 was approximately $1.39 per MMBtu, or $22.91 per ton. The average delivered cost of coal consumed at La Cygne unit 2 was approximately $1.24 per MMBtu, or $20.48 per ton.

Lawrence and Tecumseh Energy Centers: The coal-fired units located at the Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 731 MW. We purchase coal for these two energy centers under a contract with Arch Coal, Inc. Our current contract is expected to provide 100% of the coal requirement for these energy centers through 2012.

BNSF transports coal for these energy centers from Wyoming under a contract that expires in December 2013.

During 2009, the average delivered cost of coal consumed in the Lawrence units was approximately $1.47 per MMBtu, or $25.93 per ton. The average delivered cost of coal consumed in the Tecumseh units was approximately $1.45 per MMBtu, or $25.67 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 the Lawrence and Tecumseh Energy Centers. During 2009, we consumed 21.7 million MMBtu of natural gas for a total cost of $91.7 million. Natural gas accounted for approximately 7% of our total MMBtu of fuel consumed during 2009 and approximately 19% of our total fuel expense. From time to time, we may purchase derivative contracts in an effort to mitigate the effect of high natural gas prices. For additional information on our exposure to commodity price risks, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

We maintain natural gas transportation arrangements for the Abilene and Hutchinson Energy Centers with Kansas Gas Service, a division of ONEOK, Inc. (ONEOK). The Abilene Energy Center is covered under a standard tariff as a large industrial transportation customer while the Hutchinson Energy Center is covered under a rate agreement that expires on April 30, 2010. We plan to renegotiate the agreement for the Hutchinson Energy Center prior to its expiration. We meet a portion of our natural gas transportation requirements for the 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 the Gordon Evans and Murray Gill Energy Centers extends through April 1, 2020. The agreement for the State Line facility extends through April 9, 2017, while the agreement for the 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 the 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. We use No. 6 oil when natural gas is unavailable. During 2009, we did not use No. 6 oil.

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 reduced availability of natural gas for limited periods.

During 2009, we consumed 0.3 million MMBtu of diesel at a total cost of $4.1 million. Diesel accounted for less than 1% of our total MMBtu of fuel consumed during 2009 and approximately 1% of our total fuel expense.

Nuclear Generation

General

Wolf Creek is a 1,160 MW nuclear power plant located near Burlington, Kansas. KGE owns a 47% interest in Wolf Creek, or 545 MW, which represents 8% of our total generating capacity. KCPL owns an equal 47% interest and KEPCo holds the remaining 6% interest. The co-owners pay operating costs equal to their percentage ownership in Wolf Creek.

In November 2008, the Nuclear Regulatory Commission (NRC) approved Wolf Creek Nuclear Operating Corporation's (WCNOC) request for a 20-year extension of Wolf Creek's operating license until 2045. WCNOC operates Wolf Creek for its owners.

Fuel Supply

Wolf Creek has on hand or under contract all of the uranium and conversion services needed to operate Wolf Creek through March 2014 and approximately 80% of uranium and conversion services after that date through September 2018. The owners also have under contract 100% of the uranium enrichment and fabrication services required to operate Wolf Creek through March 2026.

WCNOC has entered into all uranium, uranium conversion and uranium enrichment arrangements, as well as the fabrication agreements, in the ordinary course of business.

Spent Nuclear Fuel and High-Level Radioactive Waste

Under the Nuclear Waste Policy Act of 1982, the 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 $3.7 million in 2009, $3.5 million in 2008 and $4.4 million in 2007. We include these costs in fuel and purchased power expense.

The NRC continues its technical licensing review of a DOE application for authority to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada. In February 2010, the DOE announced its intent to withdraw the application, which would end the licensing process. 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.

Low-Level Radioactive Waste

Wolf Creek disposes of most of its low-level radioactive waste at an existing third-party repository in Utah. We expect that this site will remain available to Wolf Creek. In late 2009, Wolf Creek contracted with a waste processor that will 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.

Outages

Wolf Creek operates on an 18-month planned refueling and maintenance outage schedule. Wolf Creek was shut down for 43 days in 2009 for refueling and maintenance. 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 outages. Wolf Creek's next refueling and maintenance outage is scheduled for spring of 2011.

An extended or unscheduled shutdown 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 at wholesale.

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.

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 the 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 by the KCC of a "funding schedule" prepared by the owner of the nuclear facility detailing how it plans to fund the future-year dollar amount of its pro rata share of the plant.

In August 2009, the KCC approved Wolf Creek's updated nuclear decommissioning site study. Based on the study, our share of decommissioning costs, including decontamination, dismantling and site restoration, is estimated to be $279.0 million. This amount compares to the prior site study estimate of $243.3 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.

In the prices we charge, we are allowed to recover nuclear decommissioning costs over the life of Wolf Creek, which is through 2045. The NRC requires that funds sufficient to meet nuclear decommissioning obligations be held in 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 adversely affected if we were not allowed to recover in our prices the full amount of the funding requirement.

We recovered in our prices and deposited in an external trust fund for nuclear decommissioning approximately $2.9 million in each of 2009, 2008 and 2007. We record our investment in the nuclear decommissioning trust fund at fair value. The fair value approximated $112.3 million as of December 31, 2009, and $85.6 million as of December 31, 2008.

Wind Generation

Our new wind generation facilities began operation in 2009. We produced 288,254 megawatt hours (MWh) of electricity at our wind generation facilities and purchased an additional 308,498 MWh of wind generation through purchase power agreements during the year. We expect to continue to produce and purchase significant amounts of wind generation in the future. In January 2010, we reached an agreement with a third party to acquire the development rights for a site we believe is capable of supporting up to 500 MW of wind generation. We expect to develop the site in phases with the initial phase potentially completed by the end of 2012, subject to regulatory approvals and the pace of development of new transmission facilities in western Kansas.

Other Fuel Matters

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

	2009	2008	2007
Per MMBtu:			
Nuclear	$ 0.47	$ 0.44	$ 0.43
Coal	1.51	1.42	1.27
Natural gas	4.22	7.77	6.51
Diesel/oil	15.58	21.01	15.18
Per MWh Generation:			
Nuclear	$ 4.87	$ 4.57	$ 4.46
Coal	16.79	15.75	13.92
Natural gas/diesel/oil	48.52	79.50	67.65
All generating stations	17.18	18.99	15.51

Purchased Power

We purchase electricity in addition to generating it ourselves. Factors that cause us to make such purchases include planned and unscheduled outages at our generating plants, prices for wholesale energy compared to generation costs, extreme 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 2009, purchased power comprised approximately 11% of our total fuel and purchased power expense. The weighted average cost of purchased power per MWh was $35.62 in 2009, $58.96 in 2008 and $61.04 in 2007.

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 financial instruments, including future contracts, options and swaps, and we trade energy commodity contracts.

Competition and Deregulation

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 how 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, less an administrative charge, the amounts it collects from transmission users. We record in other revenue amounts we receive for providing transmission service.

Real-Time Energy Imbalance Market

The SPP implemented a real-time energy imbalance market as required by FERC to accommodate financial settlement of energy imbalances within the SPP region. The objective of this real-time market system 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 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 sales of electricity, 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 by formula, which reduces 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 formal rate case, which lengthens the period of time between making and recovering expenditures.

KCC Proceedings

On February 2, 2010, we filed an application with the KCC to adjust our prices to include updated transmission costs as reflected in our transmission formula rate discussed below. If approved by regulators, we estimate that this will increase our annual retail revenues by $6.4 million. We expect the KCC to issue an order on our request in March 2010.

On January 27, 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with our investments in natural gas and wind generation facilities that were not included in the price increase approved by the KCC in its January 21, 2009, order discussed below. The new prices were effective February 2010 and are expected to increase our annual retail revenues by $17.1 million.

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. At the time of a future rate case, we expect to amortize such regulatory asset or liability as part of resetting base rates.

On May 29, 2009, the KCC issued an order allowing us to adjust our prices to include costs associated with environmental investments made in 2008. This change went into effect on June 1, 2009, and is expected to increase our annual retail revenues by $32.5 million.

On March 6, 2009, the KCC issued an order allowing us to adjust our prices to include updated transmission costs. This change went into effect on March 13, 2009, and is expected to increase our annual retail revenues by $31.8 million.

On January 21, 2009, the KCC issued an order expected to increase our annual retail prices by $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 became effective on February 3, 2009.

FERC Proceedings

Requests for Changes in Rates

On October 15, 2009, we filed our updated transmission formula rate which includes projected 2010 transmission capital expenditures and operating costs. Our updated transmission formula rate was effective January 1, 2010, and is expected to increase our annual transmission revenues by $16.8 million. This filing provides the basis for requesting a change in our prices for updated transmission costs under the jurisdiction of the KCC as noted above.

In July and August 2009, FERC approved our requests to implement a cost-based formula rate for two of our wholesale customers. The use of a cost-based formula rate allows us to adjust our prices to reflect changes in our cost of service. On January 12, 2010, FERC issued an order accepting our request to implement a cost-based formula rate similar to that described above that would be applicable for sales to other wholesale customers. The cost-based formula rate was effective as of December 1, 2009.

Request for Increase in Revolving Credit Facility

On January 27, 2010, FERC approved our request for authority to issue short-term securities and pledge KGE mortgage bonds in order to increase the size of Westar Energy's revolving credit facility from $750.0 million to $1.0 billion. We have not yet exercised our authority to increase the size of the facility.

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, and have tended to become more stringent over time. These 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 our 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 capital and other expenditures to comply with environmental laws and regulations. Certain of these costs are recoverable through the environmental cost recovery rider (ECRR), which allows for the more timely inclusion in retail prices of costs associated with capital expenditures tied directly to environmental improvements, including those required by the Clean Air Act. However, there can be no assurance that we will be able to recover all such costs from our customers or that the costs to comply with existing or future environmental laws and regulations will not have a material adverse effect on our consolidated financial results.

Air Emissions

The Clean Air Act, state laws and implementing regulations impose, among other things, limitations on pollutants generated during our operations, including sulfur dioxide (SO_2), particulate matter and nitrogen oxides (NOx).

Certain Kansas Department of Health and Environment (KDHE) regulations applicable to our generating facilities prohibit the emission of SO_2 in excess of prescribed levels. In order to meet these standards, we use low-sulfur coal and natural gas and have equipped some of our generating facilities with pollution control equipment.

In addition, we must comply with the provisions of the Clean Air Act Amendments of 1990 that require a reduction in SO_2 and NOx. We have installed continuous emissions monitoring and reporting equipment in order to meet these requirements.

Title IV of the Clean Air Act created an SO_2 allowance and trading program as part of the federal acid rain program. Under the allowance and trading program, the Environmental Protection Agency (EPA) allocated annual SO_2 allowances for each affected unit. An SO_2 allowance is a limited authorization to emit one ton of SO_2 during a calendar year. At the end of each year, each emitting unit must have enough allowances to cover its 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 allowances in the market in which such allowances are traded. In 2009, we had SO_2 allowances adequate to meet planned generation and we expect to have enough in 2010. In the future if we need to purchase additional air emission allowances our operating costs would increase. We recover, and would expect to continue to recover, the cost of such allowances through the RECA. The price of air emission allowances is determined by regulations and market forces and changes over time.

We have an agreement with the KDHE to implement a plan to install new equipment to reduce regulated emissions from our generating fleet. The projects are designed to meet requirements of the Clean Air Visibility Rule and significantly reduce plant emissions.

While an earlier issued EPA rule on mercury was vacated by a U.S. Court of Appeals ruling, the Obama administration has indicated that it intends to enact stricter, technology-based regulations on mercury emissions. Our costs to comply with mercury emission requirements could be material.

Environmental requirements have been changing substantially and have become more stringent over time. Accordingly, we may be required to further reduce emissions of presently regulated gases and substances, such as SO_2, NOx, particulate matter and mercury, and we may be required to reduce or limit emissions of gases and substances not presently regulated (e.g., carbon dioxide (CO_2)). Proposals and bills in those respects include:

- the EPA's national ambient air quality standards for particulate matter and ozone,
- regulations being developed by the EPA that will require emissions controls for mercury and other hazardous air pollutants,
- additional legislation introduced in the past few years in Congress requiring reductions of presently unregulated gases related primarily to concerns about climate change,
- state legislation introduced recently that could require mitigation of CO_2 emissions, and
- additional requirements regarding storage and disposal of non-hazardous fossil fuel combustion materials, including coal ash.

If enacted, the impact of these proposed laws and regulations on our consolidated financial results cannot be accurately predicted because of various factors outside our control including, but not limited to, the specific terms of such laws or regulations, the amount and timing of required capital expenditures, the cost of any emission allowances or credits we may be required to purchase and our ability to recover additional capital and operating expenses in prices. Based on currently available information, we cannot estimate our costs to comply with these proposed laws and regulations, but we believe such costs could be material.

Environmental Legislation

On June 26, 2009, the U.S. House of Representatives passed a bill which, if passed by the Senate and signed into law by the President, would require reductions in greenhouse gas (GHG) emissions and, even beyond that, would impose additional expense for virtually all such emissions, even those below the stated targeted emission levels. The bill identifies seven gasses, including CO_2, as GHGs, and introduces a target to reduce GHG emissions 3% below 2005 levels by 2012, 17% below 2005 levels by 2020, 42% below 2005 levels by 2030 and 83% below 2005 levels by 2050. The bill also mandates that retail electric utilities receive 6% of their power from renewable sources by 2012, with this requirement increasing to 20% by 2020; in certain circumstances, a portion of this requirement could be satisfied through energy efficiency measures. On September 30, 2009, similar legislation was introduced in the U.S. Senate. The targets for GHG emission reductions under the Senate bill are 3% below 2005 levels by 2012, 20% below 2005 levels by 2020, 42% below 2005 levels by 2030 and 83% below 2005 levels by 2050.

On April 17, 2009, the Administrator of the EPA issued a proposed finding that GHG emissions from mobile sources cause or contribute to air pollution that endangers the public health and welfare. The endangerment finding was proposed in response to a U.S. Supreme Court's ruling in April 2007 that GHGs are pollutants as defined in the Clean Air Act. If the EPA proposal becomes final, the EPA will be required to enact GHG emission standards for mobile sources. On September 15, 2009, the EPA and the U.S. Department of Transportation released a proposed joint rule that would regulate GHG emissions from passenger cars and light trucks. If the rule becomes final, it may render GHG,s including CO_2, "subject to regulation" under the Clean Air Act. On September 22, 2009, the EPA released its final rule requiring mandatory reporting of GHG emissions from all economic sectors. Our generating facilities are subject to these new reporting requirements. In addition, on September 30, 2009, the EPA issued a proposed rule under the Clean Air Act and indicated its expectation that it would enact regulations to control GHG emissions.

There is substantial uncertainty with respect to whether U.S. federal GHG legislation will be enacted into law or whether the EPA will regulate GHG emissions, and there is additional uncertainty regarding the final provisions and implementation of any potential U.S. federal GHG legislation or EPA rules regulating GHG emissions. We cannot predict with certainty the outcome of the legislative and rulemaking processes or a specific related impact on our generating facilities.

The EPA may develop new regulations, and Congress may pass new legislation, that impose additional requirements on facilities that store or dispose of non-hazardous fossil fuel combustion materials, including coal ash. If so, we may be required to change our current practices and incur additional capital expenditures and/or operating expenses to comply with these regulations.

On May 22, 2009, the State of Kansas enacted legislation that mandates, among other requirements, that more energy be derived from renewable sources. According to the law, in years 2011 through 2015 net renewable generation capacity must be 10% of the average peak demand for the three prior years. This requirement increases to 15% for years 2016 through 2019 and 20% for 2020 and thereafter. A further provision of the law is that the KCC may elect not to enforce these requirements if they result in more than a 1% increase in our prices. Along with third parties, we developed approximately 300 MW of qualifying wind generation facilities that began producing energy in late 2008 and early 2009. We estimate that we may need to add about 150 to 200 MW of additional renewable generating capacity to meet the 2011 deadline. In January 2010, we reached an agreement with a third party to acquire the development rights for a site we believe is capable of supporting up to 500 MW of wind generation. We expect to develop the site in phases with the initial phase potentially completed by the end of 2012, subject to regulatory approvals and the pace of development of new transmission facilities in western Kansas.

Environmental Costs

We will continue to make significant capital expenditures at our power plants to reduce undesirable emissions. The amount of these expenditures could materially increase or decrease 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 these capital investments. Our estimated capital expenditures associated with environmental improvements for 2010-2012 are as shown in the following table. We prepare these estimates for planning purposes and revise them from time to time.

Year	Dollar Amount (In Thousands)
2010	$ 181,200
2011	350,100
2012	414,700
Total	$ 946,000

The ECRR allows for the more timely inclusion in retail prices the costs of capital expenditures associated with environmental improvements, including those required by the Federal Clean Air Act. In order to change our prices to recognize increased operating and maintenance costs, however, we must still file a general rate case with the KCC.

EPA Lawsuit

Under Section 114(a) of the Federal Clean Air Act, the EPA is conducting investigations nationwide to determine whether modifications at coal-fired power plants are subject to the New Source Review permitting program or New Source Performance Standards. These investigations focus on whether projects at coal-fired plants were routine maintenance or whether the projects were substantial modifications that could reasonably have been expected to result in a significant net increase in emissions. The New Source Review program requires companies to obtain permits and, if necessary, install control equipment to address emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in emissions.

On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated certain requirements of the New Source Review program. On February 4, 2009, the Department of Justice (DOJ), on behalf of the EPA, filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. On January 25, 2010, we announced a settlement of the lawsuit. The settlement was filed with the court, seeking its approval. The settlement provides for us to install a selective catalytic reduction (SCR) system on one of the three Jeffrey Energy Center coal units by the end of 2014. We have not yet engineered this project; however, our preliminary estimate of the cost of this SCR is approximately $200.0 million. Depending on the NOx emission reductions attained by the single SCR and attainable through the installation of other controls on the other two Jeffrey Energy Center coal units, a second SCR system would be installed on another Jeffrey Energy Center coal unit by the end of 2016, if needed to meet NOx reduction targets. Recovery of costs to install these systems is subject to the approval of our regulators. We believe these costs are appropriate for inclusion in the prices we are allowed to charge our customers. We will also invest $5.0 million over six years in environmental mitigation projects which we will own and $1.0 million in environmental mitigation projects that will be owned by a qualifying third party. We will also pay a $3.0 million civil penalty. Accordingly, we have recorded a $4.0 million liability pursuant to the terms of the settlement. We expect the court to make a decision in 2010 following the expiration of a period for public comments on March 1, 2010. If the court does not approve the settlement, and the lawsuit proceeds to trial, a decision in favor of the DOJ and EPA could require us to update or install additional emissions controls at Jeffrey Energy Center, and the additional controls could be more extensive than those required by the current settlement. Additionally, we could be required to update or install emissions controls at our other coal-fired plants, pay fines or penalties or take other remedial action. Our ultimate costs to resolve the lawsuit could be material and we would expect to incur substantial legal fees and expenses related to the defense of the lawsuit. We are not able to estimate the possible loss or range of loss if the court were to not approve the settlement.

Manufactured Gas Sites

We have been identified as being partially responsible for remediating a number of former manufactured gas sites located in Kansas and Missouri. We and the KDHE entered into a consent agreement governing all future work at the Kansas sites. Under the terms of the consent agreement, we agreed to investigate and, if necessary, remediate these sites. Pursuant to an environmental indemnity agreement with ONEOK, the current owner of some of the sites, 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. We have sole responsibility for remediation with respect to three sites.

Our liability for the former manufactured gas sites identified in Missouri is limited to $7.5 million by the terms of an environmental indemnity agreement with the purchaser of our former Missouri assets.

SEASONALITY

As a summer peaking utility, our revenues are seasonal. The third quarter typically accounts for our greatest revenues. Our sales are affected by weather conditions, the economy of our service territory and the performance of our customers.

EMPLOYEES

As of February 17, 2010, we had 2,397 employees. Our current contract with Local 304 and Local 1523 of the International Brotherhood of Electrical Workers extends through June 30, 2011. The contract covered 1,336 employees as of February 17, 2010.

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 through our Internet website at www.westarenergy.com or by responding to 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
William B. Moore	57	Director, President and Chief Executive Officer (since July 2007)	**Westar Energy, Inc.** President and Chief Operating Officer (March 2006 to June 2007) Executive Vice President and Chief Operating Officer (December 2002 to March 2006)
James J. Ludwig	51	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) Vice President, Public Affairs (January 2003 to March 2006)
Mark A. Ruelle	48	Executive Vice President and Chief Financial Officer (since January 2003)	
Douglas R. Sterbenz	46	Executive Vice President and Chief Operating Officer (since July 2007)	**Westar Energy, Inc.** Executive Vice President, Generation and Marketing (March 2006 to June 2007) Senior Vice President, Generation and Marketing (October 2001 to March 2006)
Jeffrey L. Beasley	51	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) Director, Corporate Finance (March 2005 to September 2006) Director, Accounting Services (June 2003 to March 2005)
Larry D. Irick	53	Vice President, General Counsel and Corporate Secretary (since February 2003)	
Michael Lennen	64	Vice President, Regulatory Affairs (since July 2007)	**Morris, Laing, Evans, Brock & Kennedy, Chartered** Partner (January 1990 to July 2007)
Lee Wages	61	Vice President, Controller (since December 2001)	

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

ITEM 1A. RISK FACTORS

We operate in market and regulatory environments that involve significant risks, many of which are beyond our control. In addition to the 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 and 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 effect 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 heavy damage to our equipment and facilities that 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.

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 by using approved formulae, our prices generally remain fixed until changed following a rate review. Further, the adjustments and formulae 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 advocacy groups 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 delay in implementing changes to our prices or terms of service. There can be no assurance that our regulators will judge 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 rates ultimately 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 ultimate outcome of rate proceedings, or delays in implementation of new prices regarding costs that we have already incurred, could have a significant effect on our ability to recover costs and could have a material adverse effect on our consolidated financial results.

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

We use long-term demand forecasts 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 from our forecasts. If our actual experience varies significantly from our forecasts, our financial results may be adversely affected.

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 operating initiatives, or may reduce the value of our financial assets. These and other related effects may have an adverse impact on our business and 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 financial and operational risks.

Our anticipated capital expenditures for 2010 through 2012 are approximately $2.4 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 operational risks, including:

- shortages, disruption in the delivery of, 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 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 fluctuation in the values of assets set aside for employee benefit obligations and the Wolf Creek nuclear decommissioning trust 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 nuclear decommissioning trust. 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. While the KCC has recently allowed 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 could be adversely affected.

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

Our operations are affected by economic conditions, including the current recession. 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;
- 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;
- 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.

Any of these 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 supply markets for coal, natural gas and uranium are subject to price fluctuations, availability restrictions and counterparty default. It is not possible to predict the ultimate cost or availability of these commodities. Such costs, if not recovered in the prices we are allowed to charge, could have a material adverse effect on our consolidated financial results.

We are subject to complex governmental regulation that could adversely affect our operations.

Our operations are subject to extensive regulation and require numerous permits, approvals and certificates from various governmental agencies. We must also comply with environmental legislation and associated regulations. 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.

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

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources, and health and safety. Compliance with these legal requirements requires us to commit significant capital and operating resources toward permitting, emission fees, environmental monitoring, installation and operation of pollution control equipment and purchases of air emission allowances and/or offsets.

We emit large amounts of CO_2 and other gasses through the operation of our power plants. Existing environmental laws and regulations may be revised or new laws and regulations related to GHGs may be adopted and may result in significant additional expense and operating restrictions on our generating facilities or increased compliance costs.

Costs of compliance with environmental regulations, if not recovered in the prices we are allowed to charge, could adversely affect our 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 with certainty due to our inability to predict the requirements and timing of implementation of any new environmental rule or regulation related to emissions.

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 active wholesale markets that expose us to price volatility for electricity and 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 of an interest in Wolf Creek, we are subject to the risks of nuclear generation, which include:

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

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

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 markets. If we were unable to recover these costs from 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, 2009, we had recorded $715.0 million of regulatory assets, net of regulatory liabilities. 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 rates 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 or liabilities, we would be required to record a charge against income in the amount of the remaining unamortized net 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 and transmission of electricity requires the use of expensive and complicated equipment, much of which is aged, and all of which requires significant ongoing maintenance. Although we have a maintenance program in place, our power plants and equipment are subject to extended or unplanned outages because of equipment failure, weather, transmission system disruption, operator error, contractor or subcontractor failure and other factors largely beyond our control. In such events, we must either produce replacement power for our other units, which may be less efficient or more expensive to operate, or purchase power from others at unpredictable and potentially higher costs in order to meet our sales obligations. 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.

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	64	—	64
Central Plains Wind Farm	Wichita County, Kansas	(a)	2009	Wind	—	—	—
Emporia Energy Center:	Emporia, Kansas						
Combustion Turbine		1	2008	Gas	45	—	45
		2	2008	Gas	45	—	45
		3	2008	Gas	47	—	47
		4	2008	Gas	46	—	46
		5	2008	Gas	161	—	161
		6	2009	Gas	159	—	159
		7	2009	Gas	160	—	160
Flat Ridge Wind Farm	Barber County, Kansas	(a)	2009	Wind	—	—	—
Gordon Evans Energy Center:	Colwich, Kansas						
Steam Turbines		1	1961	Gas—Oil	—	153	153
		2	1967	Gas—Oil	—	384	384
Combustion Turbines		1	2000	Gas	74	—	74
		2	2000	Gas	71	—	71
		3	2001	Gas	150	—	150
Diesel Generator		1	1969	Diesel	—	3	3
Hutchinson Energy Center:	Hutchinson, Kansas						
Steam Turbine		4	1965	Gas—Oil	162	—	162
Combustion Turbines		1	1974	Gas	56	—	56
		2	1974	Gas	56	—	56
		3	1974	Gas	56	—	56
		4	1975	Diesel	62	—	62
Diesel Generator		1	1983	Diesel	3	—	3
Jeffrey Energy Center (92%):	St. Marys, Kansas						
Steam Turbines		1 (b)	1978	Coal	521	144	665
		2 (b)	1980	Coal	522	145	667
		3 (b)	1983	Coal	516	143	659
La Cygne Station (50%):	La Cygne, Kansas						
Steam Turbines		1 (b)	1973	Coal	—	368	368
		2 (c)	1977	Coal	—	341	341
Lawrence Energy Center:	Lawrence, Kansas						
Steam Turbines		3	1954	Coal	50	—	50
		4	1960	Coal	108	—	108
		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	—	67	67
Spring Creek Energy Center:	Edmond, Oklahoma						
Combustion Turbines		1 (d)	2001	Gas	72	—	72
		2 (d)	2001	Gas	70	—	70
		3 (d)	2001	Gas	67	—	67
		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	70	—	70
Tecumseh Energy Center:	Tecumseh, Kansas						
Steam Turbines		7	1957	Coal	73	—	73
		8	1962	Coal	129	—	129
Combustion Turbines		1	1972	Gas	18	—	18
		2	1972	Gas	19	—	19
Wolf Creek Generating Station (47%):	Burlington, Kansas						
Nuclear		1 (b)	1985	Uranium	—	545	545
Total					4,221	2,586	6,807

(a)	Westar Energy owns Central Plains Wind Farm, which has nameplate 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 nameplate capacity of 100 MW.
(b)	We jointly own La Cygne unit 1 generating unit (50%), Wolf Creek Generating Station (47%) and State Line (40%); and jointly own and lease Jeffrey Energy Center (92%). 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 generating unit.
(d)	We acquired Spring Creek Energy Center in 2006.

We own and have in service approximately 6,200 miles of transmission lines, approximately 23,800 miles of overhead distribution lines and approximately 4,200 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 – EPA Lawsuit – FERC Investigation" and "Legal Proceedings," respectively, which are incorporated herein by reference.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

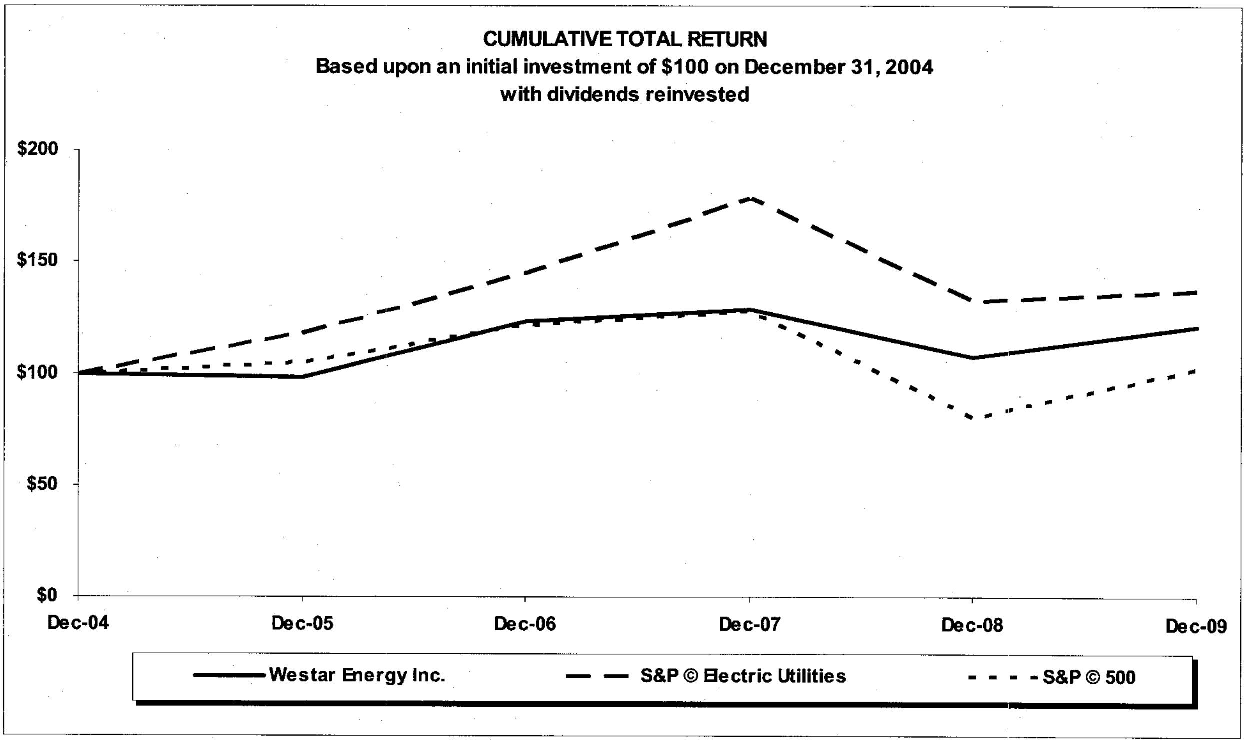
None.

PART II

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

STOCK PERFORMANCE GRAPH

The following graph compares the performance of Westar Energy's common stock during the period that began on December 31, 2004, and ended on December 31, 2009, to the Standard & Poor's 500 Index and the Standard & Poor's Electric Utility Index. 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-2004	Dec-2005	Dec-2006	Dec-2007	Dec-2008	Dec-2009
Westar Energy Inc.	$100	$ 98	$123	$128	$107	$121
Standard & Poor's 500	$100	$105	$121	$128	$ 81	$102
Standard & Poor's Electric Utilities	$100	$118	$145	$179	$133	$137

STOCK TRADING

Westar Energy's common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 17, 2010, there were 23,111 common shareholders of record. For information regarding quarterly common stock price ranges for 2009 and 2008, see Note 19 of the Notes to Consolidated Financial Statements, "Quarterly Results (Unaudited)."

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 common and preferred 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. During 2009 Westar Energy's board of directors declared four quarterly dividends of $0.30 per share, reflecting an annual dividend of $1.20 per share. On February 24, 2010, Westar Energy's board of directors declared a quarterly dividend of $0.31 per share payable to shareholders on April 1, 2010. The indicated annual dividend rate is $1.24 per share.

Westar Energy's articles of incorporation restrict the payment of dividends or the making of 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 2009. 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.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2009	2008	2007	2006	2005
			(In Thousands)		
Income Statement Data:					
Total revenues	$ 1,858,231	$ 1,838,996	$ 1,726,834	$ 1,605,743	$ 1,583,278
Income from continuing operations	141,330	178,140	168,354	165,309	134,868
Net income attributable to common stock	174,105	177,170	167,384	164,339	134,640

	As of December 31,				
	2009	2008	2007	2006	2005
			(In Thousands)		
Balance Sheet Data:					
Total assets	$ 7,525,483	$ 7,443,259	$ 6,395,430	$ 5,455,175	$ 5,210,069
Long-term obligations and mandatorily redeemable preferred stock (a)	2,610,315	2,465,968	2,022,493	1,580,108	1,681,301

	Year Ended December 31,				
	2009	2008	2007	2006	2005
Common Stock Data:					
Basic earnings per share available for common stock from continuing Operations (b)	$ 1.28	$ 1.69	$ 1.83	$ 1.86	$ 1.52
Basic earnings per share available for common stock (b)	$ 1.58	$ 1.69	$ 1.83	$ 1.86	$ 1.53
Dividends declared per share	$ 1.20	$ 1.16	$ 1.08	$ 1.00	$ 0.92
Book value per share	$ 20.59	$ 20.18	$ 19.14	$ 17.61	$ 16.31
Average equivalent common shares outstanding (in thousands) (c) (d)	109,648	103,958	90,676	87,510	86,855

(a) Includes long-term debt and capital leases.

(b) Earnings per share (EPS) amounts for 2005 through 2008 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 net proceeds of $195.4 million.

(d) In 2008, Westar Energy issued and sold approximately 12.8 million shares of common stock realizing net proceeds of $293.6 million.

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

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

EXECUTIVE SUMMARY

Overview

We are the largest electric utility in Kansas. We produce, transmit and sell electricity at retail to approximately 685,000 customers in Kansas under the regulation of the KCC. We also provide electric energy at wholesale to the electric distribution systems of 31 cities and four electric cooperatives in Kansas under the regulation of FERC. We have other 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.

Key Factors Affecting Our Performance

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

- Weather conditions;
- Customer conservation efforts;
- The economy;
- Performance of our electric generating facilities and networks;
- Conditions in the fuel, wholesale electricity and energy markets;
- Rate regulation and costs of addressing public policy initiatives;
- The availability of and our access to liquidity and capital resources; and
- Capital market conditions.

Strategy

Our strategy is to remain a vertically integrated electric utility meeting the energy needs of our customers reliably at reasonable prices. We strive to optimize flexibility in our planning and operations to be able to respond quickly to the uncertain and changing energy and environmental policies, economic conditions, regulations and technologies currently affecting or related to our business. Working constructively with our regulators and public officials is an important part of our strategy.

Significant elements of our strategy include environmental upgrades to our coal-fired power plants, the ability to use more natural gas-fired generation, the development of wind generation and the building and upgrading of transmission facilities. We also plan to invest significant resources to enhance our distribution system and to develop energy efficiency programs. Following is a summary of some of the progress we have made on these significant elements.

- During 2009, we made capital expenditures of $85.2 million at our power plants for air emission controls.

- We completed construction of the Emporia Energy Center, a natural gas-fired peaking power plant comprising approximately 660 MW of capacity, in early 2009 for a total investment of $304.5 million.
- Along with third parties, we developed approximately 300 MW of wind generation facilities at three different sites in Kansas, approximately half of which we own and half of which we purchase under long-term supply contracts. These wind generation facilities began producing energy in late 2008 and early 2009.
- We continued constructing a 345 kV transmission line in central Kansas.
- We are actively engaged in numerous programs to enable and educate customers to use energy more efficiently.

Our plans and expectations for 2010 and beyond include:

- The potential to invest an additional $946.0 million of capital expenditures at our power plants for air emissions projects over the next three years.
- In January 2010, we reached an agreement with a third party to acquire the development rights for a site we believe is capable of supporting up to 500 MW of wind generation. We expect to develop the site in phases with the initial phase potentially completed by the end of 2012, subject to regulatory approvals and the pace of development of new transmission facilities in western Kansas.
- We expect to complete in 2010 the 345 kV transmission line we are constructing in central Kansas.
- In 2010, we expect to begin planning and engineering a 345 kV transmission line that will run from a location near Wichita, Kansas, south to the Kansas-Oklahoma border.
- Upon approval from the SPP Board of Directors and appropriate regional cost allocation, Prairie Wind Transmission, LLC, a joint venture company of which we own 50%, intends to construct a new substation near Wichita, Kansas, and one near Medicine Lodge, Kansas, as well as a transmission line connecting the two substations. Prairie Wind also plans to construct a transmission line south to the Kansas-Oklahoma border from one of the two substations.
- We expect to continue improving our distribution system through enhanced vegetation management as well as equipment and process improvements.
- We expect to continue developing programs to better educate our customers about the efficient use of energy. One project we expect to undertake beginning in 2010 is SmartStar Lawrence, a smart grid project based in Lawrence, Kansas. Under this project, we will install Advanced Metering Infrastructure meters and other equipment to give customers the ability to better monitor their energy use. We applied for and have been selected by the DOE to negotiate a matching grant of approximately $19.0 million. We expect the total project cost to approximate $39.3 million.

Summary of Significant Items

Overview

Several significant items have impacted or may impact us and our operations since January 1, 2009:

- We reported net income of $175.1 million and basic EPS of $1.58 for the year ended December 31, 2009, compared to net income of $178.1 million and basic EPS of $1.69 for the year ended December 31, 2008. See "—Decrease in Net Income" below for an explanation of the decrease in net income;

- The weather in our service territory during the third quarter of 2009 was the coolest in over 40 years. As measured by cooling degree days, the weather during this period was 14% cooler than the same period in 2008 and 27% cooler than the 20-year average. The cooler weather during this period was a key contributor to the decrease in residential and commercial sales in 2009;

- The downturn in the global and U.S. economy continued to impact our business throughout 2009. See "—Economic Conditions" below for additional information;

- We received regulatory approval to increase our retail prices. For additional information, see "—Changes in Prices" below as well as Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation;"

- We reached a settlement with the IRS for years 2003 and 2004 associated with the re-characterization of a portion of the loss we incurred on the sale of Protection One from a capital loss to an ordinary loss. This settlement resulted in a 2009 net earnings benefit from discontinued operations of $33.7 million, or $0.30 per share, net of $22.8 million we paid Protection One;

- We made capital expenditures of $555.6 million during 2009. See "—Increased Capacity and Future Plans" and "—Liquidity and Capital Resources" below for additional information;

- KGE issued $300.0 million principal amount of first mortgage bonds as part of our efforts to raise the funds needed for our capital projects. We also repaid $145.1 million principal amount of unsecured senior notes. We expect to continue to issue equity and debt securities as external funds are needed to complete planned capital expenditures.

- On January 25, 2010, we announced a settlement with the DOJ of a pending lawsuit over allegations regarding environmental air regulations. The settlement provides for us to install additional air emission control equipment at Jeffrey Energy Center. We have not yet engineered this project; however, our preliminary estimate of the project cost is approximately $200.0 million. We will also invest $5.0 million over six years in environmental mitigation projects which we will own, invest $1.0 million in environmental mitigation projects that will be owned by a qualifying third party and pay a $3.0 million civil penalty. Accordingly, we have recorded a $4.0 million liability pursuant to the terms of the settlement. See Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies – EPA Lawsuit," for additional information.

Decrease in Net Income

Net income decreased $3.1 million in 2009 compared to 2008 due primarily to lower sales, lower average wholesale prices and higher income tax expense offset largely by price increases authorized by the KCC. Retail sales were 4% lower due principally to cooler weather and the effects of recessionary conditions particularly impacting our industrial sales. In 2008, we recognized $28.7 million of previously unrecognized tax benefits associated with uncertain income tax liabilities and $14.6 million in state tax incentives related to investment and jobs creation in Kansas. We did not recognize similar income tax benefits in continuing operations in 2009 resulting in higher income tax expense.

Economic Conditions

Despite improvements in the capital markets and increases in asset valuations, many aspects of the downturn in the global and U.S. economy continued to impact our business throughout 2009. Most notably, many of our industrial customers continued to experience reduced production. This resulted in decreased demand for electricity from these customers as evidenced by the 10.8% decrease in industrial sales from 2008 to 2009. Additionally, the Kansas unemployment rate increased from 5.0% in December 2008 to 7.5% in July 2009 before declining to 6.6% in December 2009. We cannot predict when these economic conditions may improve or to what extent they may continue to affect electricity sales, including effects that may spill over into residential and commercial sales, and the affect this might have on our consolidated financial results.

Changes in Prices

On May 29, 2009, the KCC issued an order allowing us to adjust our prices to include costs associated with environmental investments made in 2008. This change went into effect on June 1, 2009, and is expected to increase our annual retail revenues by $32.5 million.

On March 6, 2009, the KCC issued an order allowing us to adjust our prices to include updated transmission costs. This change went into effect on March 13, 2009, and is expected to increase our annual retail revenues by $31.8 million.

On January 21, 2009, the KCC issued an order expected to increase our annual retail prices by $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 became effective on February 3, 2009.

Current Trends

Energy Marketing

Conditions in the wholesale energy markets have made it more difficult for us to produce energy marketing margins at historical levels. We expect these conditions to persist. As a result, we anticipate future energy marketing margins below historical levels. Wholesale power market conditions include: low electricity prices relative to historical levels, lower natural gas prices, reduced demand for electricity in general and, due to an increase in the number of parties transacting through exchanges and power pools, fewer customers willing to enter into bilateral wholesale energy contracts.

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 tended to become more stringent over time. We have incurred and will continue to incur significant capital and other expenditures to comply with environmental laws and regulations. While certain of these costs are recoverable through the ECRR, we cannot assure that all such costs will be recoverable in full and in a timely manner from customers.

Potential for Greenhouse Gas Regulation

For the past several years, there has been ongoing debate regarding how the release of GHGs may affect the climate. There is pending legislation regarding the regulation of such gases and there have been court decisions affirming concerns about them.

On June 26, 2009, the U.S. House of Representatives passed a bill which, if passed by the Senate and signed into law by the President, would require reductions in GHG emissions and, even beyond that, would impose additional expense for virtually all such emissions, even those below the stated targeted emission levels. The bill identifies seven gasses, including CO_2, as GHGs, and introduces a target to reduce GHG emissions 3% below 2005 levels by 2012, 17% below 2005 levels by 2020, 42% below 2005 levels by 2030 and 83% below 2005 levels by 2050. The bill also mandates that retail electric utilities receive 6% of their power from renewable sources by 2012, with this requirement increasing to 20% by 2020; in certain circumstances, a portion of this requirement could be satisfied through energy efficiency measures. On September 30, 2009, similar legislation was introduced in the U.S. Senate. The targets for GHG emission reductions under the Senate bill are 3% below 2005 levels by 2012, 20% below 2005 levels by 2020, 42% below 2005 levels by 2030 and 83% below 2005 levels by 2050.

On April 17, 2009, the Administrator of the EPA issued a proposed finding that GHG emissions from mobile sources cause or contribute to air pollution that endangers the public health and welfare. The endangerment finding was proposed in response to a U.S. Supreme Court's ruling in April 2007 that GHGs are pollutants as defined in the Clean Air Act. If the EPA proposal becomes final, the EPA will be required to enact GHG emission standards for mobile sources. On September 15, 2009, the EPA and the U.S. Department of Transportation released a proposed joint rule that would regulate GHG emissions from passenger cars and light trucks. If the rule becomes final, it may render GHG,s including CO_2, "subject to regulation" under the Clean Air Act. On September 22, 2009, the EPA released its final rule requiring mandatory reporting of GHG emissions from all economic sectors. Our generating facilities are subject to these new reporting requirements. In addition, on September 30, 2009, the EPA issued a proposed rule under the Clean Air Act and indicated its expectation that it would enact regulations to control GHG emissions.

There is substantial uncertainty with respect to whether U.S. federal GHG legislation will be enacted into law or whether the EPA will regulate GHG emissions, and there is additional uncertainty regarding the final provisions and implementation of any potential U.S. federal GHG legislation or EPA rules regulating GHG emissions. We cannot predict with certainty the outcome of the legislative and rulemaking processes or a specific related impact on our generating facilities and consolidated financial results.

Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the 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 to other income (for equity funds) and interest expense (for borrowed funds) the amount of AFUDC capitalized as construction cost on the accompanying consolidated statements of income as follows:

	Year Ended December 31,		
	2009	2008	2007
		(In Thousands)	
Borrowed funds	$ 4,857	$ 20,536	$ 13,090
Equity funds	5,031	18,284	4,346
Total	$ 9,888	$ 38,820	$ 17,436
Average AFUDC Rates	4.2%	6.4%	6.6%

We expect both AFUDC for 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 the cost of capital is a component of future rate proceedings. In addition, short-term interest rates are extremely low by historical standards, which we do not expect to persist.

Wholesale Sales Margins

As a result of the January 21, 2009, KCC order, the amount to be credited back to retail customers, beginning in March 2009, is based on the actual margins realized from market-based wholesale sales. Prior to March 2009, the terms of the RECA required that we include, as a credit to recoverable fuel costs beginning in April of each year, an amount based on the average of the margins realized from market-based wholesale sales during the immediately prior three-year period ending June 30.

2010 Outlook

In 2010, we expect to maintain our current business strategy and regulatory approach. In addition to the price increase authorized as a result of our abbreviated rate case, we anticipate other price increases in the form of rate formulae adjustments to take effect in 2010. We also expect a return to normal weather, which we expect to result in residential and commercial sales trends more in line with historical levels. We expect industrial sales to remain below the levels experienced previous to the economic downturn and to be not much different than in 2009. As mentioned above, we anticipate future energy marketing margins below historical levels due to changes in wholesale energy market conditions that we believe will persist. We expect operating and maintenance as well as selling, general and administrative expenses to trend in line with historic labor increases and inflation rates. We expect depreciation expense to increase in 2010 as a result of plant additions during the year. Furthermore, we expect to contribute $37.7 million to our pension and post-retirement benefit plans and Wolf Creek's pension plan in 2010. We plan to increase capital spending in 2010 as provided under "—Future Cash Requirements" below. As a result, in January and February 2010, Westar Energy issued 1.2 million shares of common stock for proceeds of $25.0 million through a Sales Agency Financing Agreement with a bank. Westar Energy may issue additional shares of common stock in 2010.

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 improbable 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, 2009, we had recorded regulatory assets currently subject to recovery in future prices of approximately $855.8 million and regulatory liabilities of $140.7 million as discussed in greater detail in Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies – Regulatory Accounting." We believe that it is probable that our regulatory assets will be recovered in the future.

Pension and Other 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 other 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 will result in changes to regulatory assets, regulatory liabilities or the amount of related pension and other post-retirement liabilities reflected on our consolidated balance sheets. Such changes may also require cash contributions.

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

Actuarial Assumption	Change in Assumption	Change in Projected Benefit Obligation (a)	Change in Pension Liability (a)	Annual Change in Projected Pension Expense (a)
			(In Thousands)	
Discount rate	0.5% decrease	$ 52,594	$ 52,594	$ 5,304
	0.5% increase	(49,220)	(49,220)	(5,171)
Salary scale	0.5% decrease	(14,530)	(14,350)	(2,895)
	0.5% increase	14,643	14,643	2,982
Rate of return on plan assets	0.5% decrease	—	—	2,717
	0.5% increase	—	—	(2,717)

(a) Increases or decreases due to changes in actuarial assumptions result 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 on our post-retirement benefit plans other than pension plans.

Actuarial Assumption	Change in Assumption	Change in Projected Benefit Obligation (a)	Change in Post-retirement Liability (a)	Annual Change in Projected Post-retirement Expense (a)
			(In Thousands)	
Discount rate	0.5% decrease	$ 6,952	$ 6,952	$ 363
	0.5% increase	(6,615)	(6,615)	(375)
Rate of return on plan assets	0.5% decrease	—	—	312
	0.5% increase	—	—	(312)

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

Revenue Recognition – Energy 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.

The accuracy of 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 had estimated unbilled revenue of $56.6 million as of December 31, 2009, and $47.7 million as of December 31, 2008. The increase in unbilled revenue reflects price increases as discussed in Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation."

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 sale 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 resulting unrealized gains and losses as energy marketing long-term or short-term assets and 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 tables below show the fair value of energy marketing contracts that were outstanding as of December 31, 2009, their sources and maturity periods.

	Fair Value of Contracts (In Thousands)
Net fair value of contracts outstanding as of December 31, 2008 (a).............	$ 50,364
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period..................................	(26,523)
Changes in fair value of contracts outstanding at the beginning and end of the period..	(18,795)
Fair value of new contracts entered into during the period.............................	(605)
Net fair value of contracts outstanding as of December 31, 2009 (b).............	$ 4,441

(a) Approximately $36.3 million of the fair value of energy marketing contracts was recognized as a regulatory liability.
(b) Approximately $7.6 million and $6.0 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 as of December 31, 2009, 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
			(In Thousands)		
Prices actively quoted (futures)	$ (1,654)	$ (1,654)	$ —	$ —	$ —
Prices provided by other external sources (swaps and forwards)...............................	5,797	(4,967)	6,684	4,080	—
Prices based on option pricing models (options and other) (a)..............................	298	619	(242)	(79)	—
Total fair value of contracts outstanding........	$ 4,441	$ (6,002)	$ 6,442	$ 4,001	$ —

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

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 for carryforwards of 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 gain income 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. We report the effect of a change in the valuation allowance in the current period tax expense.

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 exposures. 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), 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, 2009 and 2008, we have recorded AROs of $119.5 million and $95.1 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 recover in our prices the costs to dispose of plant assets that do not represent legal retirement obligations. As of December 31, 2009 and 2008, we had $68.1 million and $50.1 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in our prices compared to removal costs incurred.

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 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 – EPA Lawsuit – FERC Investigation" 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 energy made to residential, commercial and industrial customers.

Other retail: Sales of energy for lighting public streets and highways, net of revenue subject to refund.

Wholesale: Sales of energy 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 energy that have yet to settle. Margins realized from these sales serve to lower our retail prices.

Energy marketing: Includes: (i) transactions based on market prices and volumes generally unrelated to the production of our generating assets; (ii) financially settled products and physical transactions sourced outside of our control area; (iii) fees we earn for marketing services that we provide for third parties; and (iv) changes in valuations of contracts related to those transactions listed in (i) and (ii) above that have yet to settle.

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.

Electric utility revenues are significantly impacted by such things as rate regulation, fuel costs, customer conservation efforts, the economy of our service area and competitive forces. Changing weather also affects the amount of electricity our customers use. As a summer peaking utility, our sales are seasonal and the third quarter typically accounts for our greatest sales. Hot summer temperatures and cold winter temperatures prompt more demand, especially among our 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 and transmission availability.

2009 Compared to 2008

Below we discuss our operating results for the year ended December 31, 2009, compared to the results for the year ended December 31, 2008. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 576,896	$ 516,926	$ 59,970	11.6
Commercial	529,847	485,016	44,831	9.2
Industrial	291,754	291,863	(109)	(b)
Other retail	(18,516)	(6,093)	(12,423)	(203.9)
Total Retail Revenues	1,379,981	1,287,712	92,269	7.2
Wholesale	308,269	413,809	(105,540)	(25.5)
Energy marketing	15,440	14,521	919	6.3
Transmission (a)	132,450	98,549	33,901	34.4
Other	22,091	24,405	(2,314)	(9.5)
Total Revenues	1,858,231	1,838,996	19,235	1.0
OPERATING EXPENSES:				
Fuel and purchased power	534,864	694,348	(159,484)	(23.0)
Operating and maintenance	516,930	471,838	45,092	9.6
Depreciation and amortization	251,534	203,738	47,796	23.5
Selling, general and administrative	199,961	184,427	15,534	8.4
Total Operating Expenses	1,503,289	1,554,351	(51,062)	(3.3)
INCOME FROM OPERATIONS	354,942	284,645	70,297	24.7
OTHER INCOME (EXPENSE):				
Investment earnings (losses)	12,658	(10,453)	23,111	221.1
Other income	7,128	29,658	(22,530)	(76.0)
Other expense	(17,188)	(15,324)	(1,864)	(12.2)
Total Other Income	2,598	3,881	(1,283)	(33.1)
Interest expense	157,360	106,450	50,910	47.8
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	200,180	182,076	18,104	9.9
Income tax expense	58,850	3,936	54,914	(c)
INCOME FROM CONTINUING OPERATIONS	141,330	178,140	(36,810)	(20.7)
Results of discontinued operations, net of tax	33,745	—	33,745	(c)
NET INCOME	175,075	178,140	(3,065)	(1.7)
Preferred dividends	970	970	—	—
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 174,105	$ 177,170	$ (3,065)	(1.7)
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING:				
Basic earnings available from continuing operations	$ 1.28	$ 1.69	$ (0.41)	(24.3)
Discontinued operations, net of tax	0.30	—	0.30	(c)
Basic earnings per common share	$ 1.58	$ 1.69	$ (0.11)	(6.5)

(a) **Transmission:** Reflects revenue derived from an SPP network transmission tariff. In 2009, our SPP network transmission costs were $105.4 million. This amount, less $11.2 million retained by the SPP as administration cost, was returned to us as revenue. In 2008, our SPP network transmission costs were $77.9 million with an administration cost of $6.7 million retained by the SPP.

(b) Change less than 0.1%.

(c) Change greater than 1000%.

Gross Margin

Fuel and purchased power costs fluctuate as retail and wholesale sales requirements and unit costs change. As permitted by regulators, we adjust our retail prices to reflect changes in the costs of fuel and purchased power needed to serve our customers. Fuel and purchased power costs for our wholesale customers are recovered in 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 a minimal impact on net income. For this reason, we believe that gross margin, although a non-GAAP measurement, is a useful measure for understanding and analyzing changes in our operating performance from one period to the next. Gross margin is calculated as total revenues less fuel and purchased power costs and SPP network transmission costs. Transmission costs reflect the costs of providing network transmission service. We recognize a significant amount of transmission revenue in connection with such service. We record these costs in operating and maintenance expense on our consolidated statements of income. The following table summarizes our gross margin for the years ended December 31, 2009 and 2008.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars In Thousands)			
REVENUES:				
Residential	$ 576,896	$ 516,926	$ 59,970	11.6
Commercial	529,847	485,016	44,831	9.2
Industrial	291,754	291,863	(109)	(a)
Other retail	(18,516)	(6,093)	(12,423)	(203.9)
Total Retail Revenues	1,379,981	1,287,712	92,269	7.2
Wholesale	308,269	413,809	(105,540)	(25.5)
Energy marketing	15,440	14,521	919	6.3
Transmission	132,450	98,549	33,901	34.4
Other	22,091	24,405	(2,314)	(9.5)
Total Revenues	1,858,231	1,838,996	19,235	1.0
Less: Fuel and purchased power expense	534,864	694,348	(159,484)	(23.0)
SPP network transmission costs	105,401	77,871	27,530	35.4
Gross Margin	$ 1,217,966	$ 1,066,777	$ 151,189	14.2

(a) Change less than 0.1%.

The following table reflects changes in electric sales for the years ended December 31, 2009 and 2008. No sales are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to the amount of electricity we generate.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Thousands of MWh)			
SALES:				
Residential	6,404	6,494	(90)	(1.4)
Commercial	7,235	7,363	(128)	(1.7)
Industrial	5,145	5,769	(624)	(10.8)
Other retail	88	88	—	—
Total Retail	18,872	19,714	(842)	(4.3)
Wholesale	8,788	9,384	(596)	(6.4)
Total	27,660	29,098	(1,438)	(4.9)

The increase in gross margin in 2009 compared to 2008 was due principally to the increase in total retail revenues. Total retail revenues increased primarily as a result of price increases authorized by the KCC, which more than offset the decrease in total retail sales. The decreases in both residential and commercial sales were attributable primarily to cooler weather, particularly during the third quarter of 2009. As measured by cooling degree days, the weather during the third quarter of 2009 was 14% cooler than the same period in 2008 and 27% cooler than the 20-year average. Industrial sales decreased due principally to the effects of recessionary conditions that served to reduce industrial demand for electricity. In addition, wholesale revenues decreased compared to 2008 due principally to a 17% lower average market price for these sales that was the result, primarily, of reduced demand and lower natural gas prices. Substantially all of the margins realized on these sales are returned to our customers. The increase in energy marketing was attributable primarily to our having settled forward contracts for the sale of electricity on favorable terms in 2009. Offsetting these favorable settlements was lower demand generally, lower market prices and more customers transacting through power pools and exchanges as opposed to entering into bilateral agreements with us.

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, 2009 and 2008.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars In Thousands)			
Gross margin	$ 1,217,966	$ 1,066,777	$ 151,189	14.2
Add: SPP network transmission costs	105,401	77,871	27,530	35.4
Less: Operating and maintenance expense	516,930	471,838	45,092	9.6
Depreciation and amortization expense	251,534	203,738	47,796	23.5
Selling, general and administrative expense	199,961	184,427	15,534	8.4
Income from operations	$ 354,942	$ 284,645	$ 70,297	24.7

Other Operating Expenses and Other Income and Expense Items

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars in Thousands)			
Operating and maintenance expense	$ 516,930	$ 471,838	$ 45,092	9.6

Operating and maintenance expense increased due primarily to a $27.5 million increase in SPP network transmission costs, which was offset by higher transmission revenues of $33.9 million. Maintenance expense increased $8.2 million due principally to a $5.5 million increase in amounts expensed for previously deferred storm costs and higher maintenance costs of $3.3 million for our new generating facilities.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars in Thousands)			
Depreciation and amortization expense	$ 251,534	$ 203,738	$ 47,796	23.5

We completed a number of large construction projects in the last two years. Consequently, depreciation and amortization expense increased primarily as a result of these plant additions. During 2009, we recorded depreciation expense of $9.3 million for Emporia Energy Center, $10.3 million for wind generation facilities and $5.7 million for various transmission projects. During 2008, we recorded depreciation expense of $3.4 million for Emporia Energy Center and $0.2 million for the same transmission projects described above. We did not record any depreciation expense for the wind generation facilities in 2008 because they were not yet in service.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars in Thousands)			
Selling, general and administrative expense	$ 199,961	$ 184,427	$ 15,534	8.4

The increase in selling, general and administrative expense was due primarily to a $7.0 million increase in pension and other employee benefit costs. In addition, we recorded a $4.0 million expense related to the settlement of the EPA lawsuit discussed in Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies."

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars in Thousands)			
Investment earnings (losses)	$ 12,658	$ (10,453)	$ 23,111	221.1

Investment earnings increased compared to 2008 due principally to our having recorded an $8.4 million gain on investments held in a trust to fund non-qualified retirement benefits. We recorded a $10.9 million loss on those investments in 2008.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars in Thousands)			
Other income	$ 7,128	$ 29,658	$ (22,530)	(76.0)

Other income decreased due principally to our having recorded less equity AFUDC and corporate-owned life insurance (COLI) benefit in 2009. We recorded $5.0 million of equity AFUDC in 2009 compared to $18.3 million of equity AFUDC recorded during the prior year. This decrease reflects the completion of several large construction projects in 2009. In addition, we recorded $0.4 million of COLI benefit in 2009 compared to $5.8 million of COLI benefit recorded in 2008.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars in Thousands)			
Interest expense	$ 157,360	$ 106,450	$ 50,910	47.8

In 2008, we reversed $17.8 million of accrued interest associated with uncertain income tax positions, which reduced interest expense. We did not record such a reversal in 2009 and, as a result, our interest expense is higher. Absent this reversal, interest expense increased $33.1 million compared to 2008 due principally to interest on additional debt issued to fund capital investments. Contributing to the increase was our having recorded $15.7 million less for capitalized interest as a result of completing several large construction projects in 2009. These factors were offset partially by a $7.5 million decrease in interest related to lower interest rates and less borrowing under Westar Energy's revolving credit facility.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars in Thousands)			
Income tax expense	$ 58,850	$ 3,936	$ 54,914	(a)

(a) Change greater than 1000%.

In 2008, we recognized $28.7 million of previously unrecognized income tax benefits associated with uncertain income tax positions and $14.6 million in state tax credits related to investment and jobs creation within the state of Kansas, both of which decreased income tax expense. We did not recognize similar income tax benefits in continuing operations in 2009.

2008 Compared to 2007

Below we discuss our operating results for the year ended December 31, 2008, compared to the results for the year ended December 31, 2007. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 516,926	$ 491,163	$ 25,763	5.2
Commercial	485,016	448,368	36,648	8.2
Industrial	291,863	264,566	27,297	10.3
Other retail	(6,093)	(18,133)	12,040	66.4
Total Retail Revenues	1,287,712	1,185,964	101,748	8.6
Wholesale	413,809	380,443	33,366	8.8
Energy marketing	14,521	36,978	(22,457)	(60.7)
Transmission (a)	98,549	97,717	832	0.9
Other	24,405	25,732	(1,327)	(5.2)
Total Revenues	1,838,996	1,726,834	112,162	6.5
OPERATING EXPENSES:				
Fuel and purchased power	694,348	544,421	149,927	27.5
Operating and maintenance	471,838	473,525	(1,687)	(0.4)
Depreciation and amortization	203,738	192,910	10,828	5.6
Selling, general and administrative	184,427	178,587	5,840	3.3
Total Operating Expenses	1,554,351	1,389,443	164,908	11.9
INCOME FROM OPERATIONS	284,645	337,391	(52,746)	(15.6)
OTHER INCOME (EXPENSE):				
Investment (losses) earnings	(10,453)	6,031	(16,484)	(273.3)
Other income	29,658	6,726	22,932	340.9
Other expense	(15,324)	(14,072)	(1,252)	(8.9)
Total Other Income (Expense)	3,881	(1,315)	5,196	395.1
Interest expense	106,450	103,883	2,567	2.5
INCOME BEFORE INCOME TAXES	182,076	232,193	(50,117)	(21.6)
Income tax expense	3,936	63,839	(59,903)	(93.8)
NET INCOME	178,140	168,354	9,786	5.8
Preferred dividends	970	970	—	—
EARNINGS AVAILABLE FOR COMMON STOCK	$ 177,170	$ 167,384	$ 9,786	5.8
BASIC EARNINGS PER SHARE	$ 1.69	$ 1.83	$ (0.14)	(7.7)

(a) **Transmission:** Reflects revenue derived from an SPP network transmission tariff. In 2008, our SPP network transmission costs were $77.9 million. This amount, less $6.7 million retained by the SPP as administration cost, was returned to us as revenue. In 2007, our SPP network transmission costs were $82.0 million with an administration cost of $9.2 million retained by the SPP.

Gross Margin

The following table summarizes our gross margin for the years ended December 31, 2008 and 2007.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Dollars In Thousands)			
REVENUES:				
Residential	$ 516,926	$ 491,163	$ 25,763	5.2
Commercial	485,016	448,368	36,648	8.2
Industrial	291,863	264,566	27,297	10.3
Other retail	(6,093)	(18,133)	12,040	66.4
Total Retail Revenues	1,287,712	1,185,964	101,748	8.6
Wholesale	413,809	380,443	33,366	8.8
Energy marketing	14,521	36,978	(22,457)	(60.7)
Transmission	98,549	97,717	832	0.9
Other	24,405	25,732	(1,327)	(5.2)
Total Revenues	1,838,996	1,726,834	112,162	6.5
Less: Fuel and purchased power expense	694,348	544,421	149,927	27.5
SPP network transmission costs	77,871	81,998	(4,127)	(5.0)
Gross margin	$ 1,066,777	$ 1,100,415	$ (33,638)	(3.1)

The following table reflects changes in electric sales for the years ended December 31, 2008 and 2007. No sales are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to the amount of electricity we generate.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Thousands of MWh)			
SALES:				
Residential	6,494	6,677	(183)	(2.7)
Commercial	7,363	7,537	(174)	(2.3)
Industrial	5,769	5,819	(50)	(0.9)
Other retail	88	91	(3)	(3.3)
Total Retail	19,714	20,124	(410)	(2.0)
Wholesale	9,384	10,026	(642)	(6.4)
Total	29,098	30,150	(1,052)	(3.5)

The decrease in gross margin in 2008 compared to 2007 was due primarily to the decrease in energy marketing, cooler weather, reduced margins on power sold to a few large industrial customers and additional planned outages at our base load plants. Energy marketing decreased due principally to the need to focus resources toward serving our retail customers during outages, changes in the relationships of prices among energy products historically traded and the continuing maturation of energy markets in which we participate reducing margin opportunities. Contributing to the decrease in energy marketing was the recognition of a $3.2 million customer refund obligation and a $3.0 million obligation related to claims made by an independent system operator seeking the re-pricing of transactions conducted within that operator's region in prior periods. As measured by cooling degree days, the weather during 2008 was 20% cooler than 2007 and 9% cooler than the 20-year average. This cooler weather was the primary contributor to the decreases in residential and commercial sales. Additionally, in 2008, we sold power to a few large industrial customers under contracts to which the RECA did not apply and, primarily as a result of higher fuel costs, margins on these sales were $9.9 million lower compared to 2007. All of these contracts expired in 2009. Furthermore, we had additional planned outages at our base load plants in 2008 that were longer in duration than in 2007. These additional planned outages required us to use more expensive fuel and to incur additional purchased power expense, which resulted in reduced margins on power sold despite higher prevailing market prices.

The following table reconciles income from operations with gross margin for the years ended December 31, 2008 and 2007.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Dollars In Thousands)			
Gross margin	$ 1,066,777	$ 1,100,415	$ (33,638)	(3.1)
Add: SPP network transmission costs	77,871	81,998	(4,127)	(5.0)
Less: Operating and maintenance expense	471,838	473,525	(1,687)	(0.4)
Depreciation and amortization expense	203,738	192,910	10,828	5.6
Selling, general and administrative expense	184,427	178,587	5,840	3.3
Income from operations	$ 284,645	$ 337,391	$ (52,746)	(15.6)

Other Operating Expenses and Other Income and Expense Items

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Dollars in Thousands)			
Depreciation and amortization expense	$ 203,738	$ 192,910	$ 10,828	5.6

Depreciation and amortization expense increased $10.8 million due to depreciation expense associated with more plant being in service.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Dollars in Thousands)			
Selling, general and administrative expense	$ 184,427	$ 178,587	$ 5,840	3.3

The $5.8 million increase in selling, general and administrative expense was due primarily to a $3.2 million increase in legal costs. Various court orders require that we pay legal fees incurred by two former executive officers related to the defense of criminal charges filed against them by the United States Attorneys' Office. Higher legal expenses were also related to more regulatory activities. Also contributing to the increase was $3.9 million in additional labor costs and a $1.4 million increase in bad debt expense. Offsetting these increases was a $5.0 million decrease in employee benefits expense.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Dollars in Thousands)			
Investment (losses) earnings	$ (10,453)	$ 6,031	$ (16,484)	(273.3)

Investment earnings decreased $16.5 million due primarily to our having recorded a $10.9 million loss on investments held in a trust used to fund retirement benefits. We recorded a $4.8 million gain on these investments in 2007.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Dollars in Thousands)			
Other income	$ 29,658	$ 6,726	$ 22,932	340.9

Other income increased $22.9 million due primarily to our having recorded $18.3 million of equity AFUDC in 2008 compared to $4.3 million of equity AFUDC recorded in 2007. Also contributing to the increase was a $4.8 million gain on the sale of oil in 2008. In addition, we recorded $5.8 million of COLI benefit in 2008 compared to $0.7 million of COLI benefit recorded in 2007.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Dollars in Thousands)			
Interest expense	$ 106,450	$ 103,883	$ 2,567	2.5

Interest expense increased $2.6 million due primarily to interest on additional debt issued to fund investments in capital equipment. Partially offsetting this increase was the reversal of $17.8 million of accrued interest associated with uncertain tax liabilities during 2008.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Dollars in Thousands)			
Income tax expense	$ 3,936	$ 63,839	$ (59,903)	(93.8)

Income tax expense decreased $59.9 million due to the recognition of $28.7 million of previously unrecognized tax benefits and the recognition of $14.6 million in state tax credits related to investment and jobs creation within the state of Kansas.

Financial Condition

A number of factors affected amounts recorded on our balance sheet as of December 31, 2009, compared to December 31, 2008.

Cash and cash equivalents decreased $19.1 million. Conditions in capital markets for short-term borrowing improved throughout the year as evidenced by lower interest rates. Therefore, during the year we decreased cash holdings to levels more consistent with our historical practice.

The fair market value of energy marketing contracts decreased $45.9 million to $4.4 million at December 31, 2009. This was due principally to the fair value measurement of a fuel supply contract decreasing $36.6 million. The portion of this fuel supply contract outstanding the entire period decreased $19.0 million due to decreased coal prices. Further decreasing the fair value measurement of this fuel supply contract was the settlement of a $17.6 million net gain position during the year.

Prepaid expenses decreased $21.6 million and accrued interest increased $34.8 million since December 31, 2008, due principally to a policy change under which we no longer pay interest on COLI policies in advance.

In addition, other non-current assets increased $59.8 million and other current liabilities decreased $10.2 million due primarily to a policy change to cease borrowing against future increases in the cash surrender value of our COLI policies.

Regulatory assets, net of regulatory liabilities, decreased $114.2 million to $715.0 million at December 31, 2009, from $829.2 million at December 31, 2008. Total regulatory assets decreased $96.5 million due primarily to a $70.2 million decrease in deferred employee benefit costs as a result of favorable pension plan asset performance and pension contributions, $19.1 million amortization of deferred storm costs, and $10.3 million decrease in net amounts due from customers for future income taxes. Total regulatory liabilities increased $17.7 million due principally to a $27.0 million increase in our refund obligation related to the RECA and an $18.0 million increase in removal cost for amounts collected, but not yet spent to remove retired assets. Increases were partially offset by a $30.3 million decrease in the fair value of fuel supply contracts.

Long-term debt, net of current maturities, increased $298.2 million due principally to the issuance of $300.0 million of first mortgage bonds as discussed in detail in Note 9 of the Notes to Consolidated Financial Statements, "Long-Term Debt."

Unamortized investment tax credits increased $68.4 million due to incentives we earned related to investments in plant located in the state of Kansas.

Accrued employee benefits decreased $92.6 million due primarily to favorable plan asset performance and our having contributed $44.6 million to Westar Energy's and Wolf Creek's pension plans.

Asset retirement obligations increased $24.4 million due predominately to a $20.3 million increase in our ARO to reflect revisions to the estimated costs to decommission Wolf Creek. See Note 14 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations," for additional information.

Other long-term liabilities decreased $37.9 million due primarily to a $36.4 million decrease in our long-term liability for uncertain income tax positions and related accrued interest due to the settlement of an IRS examination. See Note 10 of the Notes to Consolidated Financial Statements, "Taxes," for additional detail on our uncertain income tax positions.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Available sources of funds to operate our business include internally generated cash, Westar Energy's revolving credit facility and access to capital markets. We expect to meet our day-to-day cash requirements including, among other items: fuel and purchased power, dividends, interest payments, income taxes and pension contributions, using primarily internally generated cash and borrowings under the revolving credit facility. To meet the cash requirements for our capital investments, we expect to use internally generated cash, borrowings under the revolving credit facility and the issuance of debt and equity securities in the capital markets. We also use proceeds from the issuance of securities to repay borrowings under the revolving credit facility, with those borrowed amounts principally related to investments in capital equipment, 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.

Beginning late in the first quarter, capital market conditions improved significantly during 2009 compared to the unprecedented volatility experienced in late 2008 and early 2009. Given these improvements, we plan to increase our capital spending in 2010. Additionally, we expect to contribute less to our pension trust in 2010. We do not expect the current economic conditions to impact our 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 Resources

On February 15, 2008, FERC granted our request to issue short-term securities and pledge KGE mortgage bonds in order to increase the size of Westar Energy's revolving credit facility from $500.0 million to $750.0 million. On February 22, 2008, a syndicate of banks in the credit facility increased their commitments to $750.0 million in the aggregate with $730.0 million of the commitments terminating on March 17, 2012, and the remaining $20.0 million of commitments terminating on March 17, 2011.

Lehman Brothers Commercial Paper, Inc. (Lehman Brothers) was the participating lender with respect to the $20.0 million commitment terminating on March 17, 2011. On October 5, 2008, Lehman Brothers filed for bankruptcy protection. Under terms of the credit facility, we have the right to replace Lehman Brothers should another lender or lenders be willing to replace the $20.0 million commitment. To date, we have elected not to seek a replacement lender. As a result, until such time as we seek and locate a replacement lender or lenders, the revolving credit facility is limited to $730.0 million.

On January 27, 2010, FERC approved our request for authority to issue short-term securities and pledge KGE mortgage bonds in order to increase the size of Westar Energy's revolving credit facility to $1.0 billion. We have not yet exercised our authority to increase the size of the facility. As of February 17, 2010, $228.1 million had been borrowed and an additional $23.9 million of letters of credit had been issued under the revolving credit facility. In addition, we had $7.3 million in cash and cash equivalents as of the same date.

A default by Westar Energy or KGE under other indebtedness totaling more than $25.0 million would be a default under this facility. Westar Energy is required to maintain a consolidated indebtedness to consolidated capitalization ratio not greater than 65% at all times. At December 31, 2009, our ratio was 56%. Available liquidity under the facility is not impacted by a decline in Westar Energy's credit ratings. Also, the facility does not contain a material adverse effect clause requiring Westar Energy to represent, prior to each borrowing, that no event resulting in a material adverse effect has occurred.

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, and 10% of the principal amount of, all first mortgage bonds outstanding after giving effect to the proposed issuance. As of December 31, 2009, based on an assumed interest rate of 5.875%, approximately $350.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

Under the KGE mortgage, the issuance of bonds is subject to limitations based on the amount of bondable property additions. In addition, the mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless KGE's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than either two and one-half times the annual interest charges on, or 10% of the principal amount of, all KGE first mortgage bonds outstanding after giving effect to the proposed issuance. As of December 31, 2009, approximately $550.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

Common Stock Issuance

On May 29, 2008, Westar Energy entered into an underwriting agreement relating to the offer and sale of 6.0 million shares of its common stock. On June 4, 2008, Westar Energy issued all 6.0 million shares and received $140.6 million in total proceeds, net of underwriting discounts and fees related to the offering.

On November 15, 2007, Westar Energy entered into a forward sale agreement with a bank, as forward purchaser, relating to 8.2 million shares of its common stock. The forward sale agreement provided for the sale of Westar Energy's common stock within approximately twelve months at a stated settlement price. In connection with the forward sale agreement, the bank borrowed an equal number of shares of Westar Energy's common stock from stock lenders and sold the borrowed shares to another bank under an underwriting agreement among Westar Energy and the banks. The underwriters subsequently offered the borrowed shares to the public at a price per share of $25.25.

On December 28, 2007, Westar Energy delivered 3.1 million newly issued shares of its common stock to a bank and received proceeds of $75.0 million as partial settlement of the forward sale agreement. Additionally, on February 7, 2008, Westar Energy delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. On June 30, 2008, Westar Energy completed the forward sale agreement by delivering 3.0 million shares and receiving proceeds of $73.0 million.

On August 24, 2007, Westar Energy entered into a Sales Agency Financing Agreement with a bank. Under the terms of the agreement, Westar Energy may offer and sell shares of its common stock from time to time through the bank, as agent, up to an aggregate of $200.0 million for a period of no more than three years. Westar Energy will pay the bank a commission equal to 1% of the sales price of all shares sold under the agreement. During 2007 Westar Energy sold 0.8 million shares of common stock through the bank for $20.0 million and received $19.8 million in proceeds net of commission. During 2008 Westar Energy sold 1.1 million shares of common stock through the bank for $26.9 million and received $26.7 million in proceeds net of commission. Westar Energy did not sell any shares of common stock under this agreement during 2009. In January and February 2010, Westar Energy issued 1.2 million shares of common stock through the bank for $25.0 million. Westar Energy may issue additional shares of common stock in 2010.

On April 12, 2007, Westar Energy entered into a Sales Agency Financing Agreement with the same bank. As of July 12, 2007, Westar Energy had sold 3.7 million shares of its common stock for $100.0 million pursuant to the agreement. Westar Energy received $99.0 million in proceeds net of a commission.

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

Cash Flows from Operating Activities

Operating activities provided $478.9 million of cash in the year ended December 31, 2009, compared with cash provided from operating activity of $274.9 million during the same period of 2008. Principal contributors to the increase were our having paid $418.9 million less for fuel and purchased power and $50.5 million less for interest on our COLI policies. Partially offsetting increases were our having received $233.3 million less in customer receipts during 2009 due primarily to lower cash receipts from our wholesale customers which more than offset higher cash receipts from our retail customers and our having paid $42.1 million more in interest on debt.

Operating activities provided $274.9 million of cash in the year ended December 31, 2008, compared with cash provided from operating activity of $246.8 million during the same period of 2007. Principal contributors to the increase were additional collections from customers during 2008 due in large part to our having recovered higher fuel costs from customers through the RECA and $109.9 million in lower income tax payments in 2008 compared to the prior year. Offsetting these increases were: our having paid $53.2 million to restore our electrical system which was severely damaged by an ice storm in December 2007; additional outages occurring in 2008 at our base load plants; our having paid more for fuel and purchased power in 2008 compared to the prior year; and during 2008, we paid $15.7 million more for our share of Wolf Creek's refueling outage.

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 investment in plant on an annual basis. We spent $555.6 million in 2009, $919.0 million in 2008 and $743.8 million in 2007 on additions to property, plant and equipment. The decrease in 2009 was due principally to the completion of environmental projects, wind generation projects, transmission projects and the construction of Emporia Energy Center, which required significant amounts of cash in 2008 and 2007.

Cash Flows from Financing Activities

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.

We received net cash flows from financing activities of $648.7 million in 2008. Proceeds from the issuance of long-term debt provided $544.7 million, proceeds from the issuance of common stock provided $293.6 million and borrowings from COLI provided $64.3 million. We used cash to pay $109.6 million in dividends and to retire $101.3 million of long-term debt.

In 2007, we received net cash flows from financing activities of $502.8 million. Proceeds from the issuance of long-term debt provided $322.3 million and proceeds from the issuance of common stock provided $195.4 million. We used cash to pay $89.5 million in dividends.

Cash Flows used in Investing Activities of Discontinued Operations

We paid 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 2012, 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 improvements 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 flow, borrowings under Westar Energy's revolving credit facility and through the issuance of securities in the capital markets.

We have incurred and expect to continue to incur material costs to comply with existing and future environmental laws and regulations, all of 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. While we believe we can generally recover environmental costs through price increases, there is no guarantee that we will be able to do so.

On January 25, 2010, we announced a settlement with the DOJ of a pending lawsuit over allegations regarding environmental air regulations. The settlement was filed with the U.S. District Court in the District of Kansas, seeking its approval. The settlement provides for us to install an SCR system on one of the three Jeffrey Energy Center coal units by the end of 2014. We have not yet engineered this project; however, our preliminary estimate of the cost of this SCR is approximately $200.0 million. Depending on the NOx emission reductions attained by the single SCR and attainable through the installation of other controls on the other two Jeffrey Energy Center coal units, a second SCR system would be installed on another Jeffrey Energy Center coal unit by the end of 2016, if needed to meet NOx reduction targets. Recovery of costs to install these systems is subject to the approval of our regulators. We believe these costs are appropriate for inclusion in the prices we are allowed to charge our customers. We will also invest $5.0 million over six years in environmental mitigation projects which we will own and $1.0 million in environmental mitigation projects that will be owned by a qualifying third party. We will also pay a $3.0 million civil penalty. Accordingly, we have recorded a $4.0 million liability pursuant to the terms of the settlement. We expect the court to make a decision in 2010 following the expiration of a period for public comments on March 1, 2010. If the court does not approve the settlement, and the lawsuit proceeds to trial, a decision in favor of the DOJ and EPA could require us to update or install additional emissions controls at Jeffrey Energy Center, and the additional controls could be more extensive than those required by the current settlement. Additionally, we could be required to update or install emissions controls at our other coal-fired plants, pay fines or penalties or take other remedial action. Our ultimate costs to resolve the lawsuit could be material and we would expect to incur substantial legal fees and expenses related to the defense of the lawsuit. We are not able to estimate the possible loss or range of loss if the court were to not approve the settlement.

Capital expenditures for 2009 and anticipated capital expenditures including costs of removal for 2010 through 2012 are shown in the following table.

	Actual 2009	2010	2011	2012
		(In Thousands)		
Generation:				
Replacements and other	$ 103,867	$ 99,900	$ 106,200	$ 126,600
Additional capacity	16,598	12,300	10,100	—
Wind generation	69,461	—	—	—
Environmental	85,218	181,200	350,100	414,700
Nuclear fuel	19,751	36,100	26,700	26,100
Transmission (a)	156,577	203,600	167,800	175,100
Distribution:				
Replacements, new customers and other	92,650	102,300	114,600	118,600
Smart grid (b)	—	8,900	9,200	12,300
Other	11,515	20,300	16,000	25,300
Total capital expenditures	$ 555,637	$ 664,600	$ 800,700	$ 898,700

(a) We plan to incur additional expenditures related to our Prairie Wind Transmission joint venture.
(b) Excluding DOE matching grant.

We prepare these estimates for planning purposes and revise our estimates from time to time. Actual expenditures will differ, perhaps materially, from our estimates due to changing environmental requirements, changing costs, delays in engineering, construction or permitting, changes in the availability and cost of capital, and other factors discussed above 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 relating to mercury and CO_2 emissions.

Maturities of long-term debt as of December 31, 2009, are as follows.

Year	Principal Amount (In Thousands)
2010	$ 1,345
2011	61
2012	—
2013	—
Thereafter	2,495,663
Total long-term debt maturities	$2,497,069

Pension Obligation

As provided in the September 11, 2009, KCC order regarding pension and post-retirement benefits, we expect to fund our pension plan each year at least to a level equal to our current year pension expense. In addition, our pension plan contributions must also meet the 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.

We contributed to our pension trust \$37.3 million in 2009 and \$15.0 million in 2008. We expect to contribute approximately \$22.4 million in 2010. In 2009 and 2008, we also funded \$7.3 million and \$5.5 million, respectively, of contributions to Wolf Creek's pension trust. In 2010, we expect to fund \$4.1 million of contributions to Wolf Creek's pension trust. 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.

Debt Financings

As of December 31, 2009, we had \$121.9 million of variable rate, tax-exempt bonds. Prior to February 2008, interest rates payable under these bonds had historically been set by auctions, which occurred every 35 days. Since then, auctions for these bonds have failed, resulting in alternative index-based interest rates for these bonds of between less than 1% and 14%. On July 31, 2008, the KCC approved our request for authority permitting us to remarket or refund all or part of these auction rate bonds. On each of October 15, 2009, October 10, 2008, and August 26, 2008, KGE refinanced \$50.0 million of auction rate bonds at fixed interest rates of 5.00%, 6.00% and 5.60%, respectively, all with maturity dates of June 1, 2031. We continue to monitor the credit markets and evaluate our options with respect to the remaining auction rate bonds.

On August 3, 2009, we 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.

In addition, KGE amended its Mortgage and Deed of Trust, dated April 1, 1940, as supplemented, in June 2009 to increase the maximum amount of KGE first mortgage bonds authorized to be issued from \$2.0 billion to \$3.5 billion.

On November 25, 2008, Westar Energy issued \$300.0 million principal amount of first mortgage bonds at a discount yielding 8.750%, bearing stated interest at 8.625% and maturing on December 1, 2018. We received net proceeds of \$295.6 million.

On May 15, 2008, KGE issued $150.0 million principal amount of first mortgage bonds in a private placement transaction with $50.0 million of the principal amount bearing interest at 6.15% and maturing on May 15, 2023, and $100.0 million bearing interest at 6.64% and maturing on May 15, 2038.

In January 2008, we increased the size of our 36-month equipment financing loan agreement to $3.9 million for computer equipment purchases made in 2008. As of December 31, 2009, the balance of this loan was $1.4 million.

Proceeds from the issuance of first mortgage bonds were used to repay borrowings under Westar Energy's revolving credit facility, with those 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 agreements. We calculate these ratios in accordance with our credit agreements. These ratios are used solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2009.

Credit Ratings

Moody's Investors Service (Moody's), Standard & Poor's Ratings Group (S&P) and Fitch Investors Service (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 August 2009, Moody's upgraded its credit ratings for Westar Energy's and KGE's first mortgage bonds/senior secured debt securities. S&P changed its rating outlooks for Westar Energy's and KGE's debt securities from stable to positive in April 2009 and upgraded its credit rating for Westar Energy's unsecured debt securities in November 2008. In August 2008, Fitch upgraded its credit ratings for Westar Energy's first mortgage bonds/senior secured debt securities and unsecured debt securities as well as KGE's first mortgage bonds/senior secured debt securities. Fitch also changed its outlook for our ratings from positive to stable.

As of February 17, 2010, ratings with these agencies are as shown in the table below.

	Westar Energy First Mortgage Bond Rating	KGE First Mortgage Bond Rating	Westar Energy Unsecured Debt	Rating Outlook
Moody's	Baa1	Baa1	Baa3	Stable
S&P	BBB	BBB	BBB-	Positive
Fitch	BBB+	BBB+	BBB	Stable

In general, less favorable credit ratings make borrowing more difficult and costly. Under Westar Energy's revolving credit facility our cost of borrowing is determined in part by our credit ratings. However, our ability to borrow under the revolving credit facility is 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.

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, 2009, was $1.4 million, for which we had posted no collateral. If all credit-risk-related contingent features underlying these agreements had been triggered as of December 31, 2009, we would have been required to provide to our counterparties $0.1 million of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

Capital Structure

As of December 31, 2009 and 2008, our capital structure excluding short-term debt was as follows:

	2009	2008
Common equity	47%	48%
Preferred stock	<1%	<1%
Long-term debt	52%	51%

OFF-BALANCE SHEET ARRANGEMENTS

Forward Equity Transaction

On November 15, 2007, Westar Energy entered into a forward sale agreement relating to 8.2 million shares of its common stock. The forward sale agreement provided for the sale of Westar Energy's common stock within approximately twelve months at a stated settlement price. On December 28, 2007, Westar Energy delivered 3.1 million newly issued shares of its common stock to a bank and received proceeds of $75.0 million as partial settlement of the forward sale agreement. Additionally, on February 7, 2008, Westar Energy delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. On June 30, 2008, Westar Energy completed the forward sale agreement by delivering 3.0 million shares of its common stock and receiving proceeds of $73.0 million.

As of December 31, 2009, we did not have any additional off-balance sheet financing arrangements, other than our operating leases entered into in the ordinary course of business. For additional information on our operating leases, see Note 17 of the Notes to Consolidated Financial Statements, "Leases."

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

In the course of our business activities, we enter into a variety of obligations 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 obligations listed below include amounts for on-going needs for which contractual obligations existed as of December 31, 2009.

Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2009.

	Total	2010	2011 - 2012	2013 - 2014	Thereafter
			(In Thousands)		
Long-term debt (a)	$2,497,069	$ 1,345	$ 61	$ 250,000	$ 2,245,663
Interest on long-term debt (b)	2,476,246	148,440	296,880	296,880	1,734,046
Adjusted long-term debt	4,973,315	149,785	296,941	546,880	3,979,709
Pension and post-retirement benefit expected contributions (c)	37,700	37,700	—	—	—
Capital leases (d)	169,841	17,685	26,316	14,293	111,547
Operating leases (e)	487,569	49,181	98,903	89,893	249,592
Fossil fuel (f)	1,452,660	303,476	528,925	217,037	403,222
Nuclear fuel (g)	353,606	34,232	46,452	45,301	227,621
Unconditional purchase obligations	186,690	113,946	58,084	14,660	—
Unrecognized income tax benefits including interest (h)	6,079	6,079	—	—	—
Total contractual obligations, including adjusted long-term debt	$7,667,460	$ 712,084	$1,055,621	$ 928,064	$ 4,971,691

(a) See Note 9 of the Notes to Consolidated Financial Statements, "Long-Term Debt," for individual long-term debt maturities.
(b) We calculate interest on our variable rate debt based on the effective interest rate as of December 31, 2009.
(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, including our 8% leasehold interest in Jeffrey Energy Center.
(e) Includes leases for La Cygne unit 2, operating facilities, operating equipment, office space, office equipment, vehicles and railcars as well as other miscellaneous commitments.
(f) Coal and natural gas commodity and transportation contracts.
(g) Uranium concentrates, conversion, enrichment, fabrication and spent nuclear fuel disposal.
(h) We have an additional $3.6 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 tax benefits are settled at the amounts accrued as of December 31, 2009.

Commercial Commitments

Our commercial commitments as of December 31, 2009, consist of outstanding letters of credit that expire in 2010, some of which automatically renew annually. The letters of credit are comprised of $9.8 million related to worker's compensation, $6.2 million related to new transmission projects, $4.5 million related to our energy marketing and trading activities and $4.5 million related to other operating activities for a total outstanding balance of $25.0 million.

OTHER INFORMATION

Stock-Based Compensation

We use restricted share units (RSUs) exclusively for our stock-based compensation awards. Total unrecognized compensation cost related to RSU awards was $2.6 million as of December 31, 2009. We expect to recognize these costs over a remaining weighted-average period of 2.3 years. There were no modifications of awards during the years ended December 31, 2009, 2008 or 2007.

Environmental Regulation

On May 22, 2009, the State of Kansas enacted legislation that mandates, among other requirements, that more energy be derived from renewable sources. According to the law, in years 2011 through 2015 net renewable generation capacity must be 10% of the average peak demand for the three prior years. This requirement increases to 15% for years 2016 through 2019 and 20% for 2020 and thereafter. A further provision of the law is that the KCC may elect not to enforce these requirements if they result in more than a 1% increase in our prices. We estimate that we may need to add about 150 to 200 MW of additional renewable generating capacity to meet the 2011 requirement. In January 2010, we reached an agreement with a third party to acquire the development rights for a site we believe is capable of supporting up to 500 MW of wind generation. We expect to develop the site in phases with the initial phase potentially completed by the end of 2012, subject to regulatory approvals and the pace of development of new transmission facilities in western Kansas.

Additionally, the EPA may develop new regulations, and Congress may pass new legislation, that impose additional requirements on facilities that store or dispose of non-hazardous fossil fuel combustion materials, including coal ash. If so, we may be required to change our current practices and incur additional capital expenditures and/or operating expenses to comply with these regulations.

The degree to which we may need to produce renewable energy or change our current practices related to the storage and disposal of non-hazardous materials and the timing of when equipment may be required are uncertain. Both the timing and nature of required investments and actions depend on specific outcomes that result from interpretation of new and existing regulation and legislation. Although we would expect to recover in the prices we charge our customers the costs that we incur to comply with environmental regulations, we can provide no assurance that we will be able to fully and timely do so. Failure to recover these associated costs could have a material adverse effect on our consolidated financial results.

New Accounting Pronouncements

We prepare our consolidated financial statements in accordance with GAAP for the United States of America. To address current issues in accounting, regulatory bodies have issued the following new accounting pronouncements that may affect our accounting and/or disclosure.

FASB Codification

In June 2009, the Financial Accounting Standards Board (FASB) approved its Accounting Standards Codification (Codification) as the exclusive authoritative reference for U.S. GAAP to be applied by nongovernmental entities. SEC rules and interpretive releases are still considered authoritative GAAP for SEC registrants. The Codification, which changes the referencing of accounting standards, is effective for interim and annual reporting periods ending after September 15, 2009. We adopted the Codification effective July 1, 2009, without a material impact on our consolidated financial results.

Variable Interest Entities

In June 2009, FASB issued guidance that amends the consolidation guidance for variable interest entities (VIEs). The amended guidance requires a qualitative assessment rather than a quantitative assessment in determining the primary beneficiary of a VIE and significantly changes the consolidation criteria to be considered in determining the primary beneficiary. Pursuant to the amended guidance, there is no exclusion, or "grandfathering," of VIEs that were not consolidated under prior guidance. This amended guidance is effective for annual reporting periods beginning after November 15, 2009. We adopted the guidance effective January 1, 2010, and, as a result, expect to consolidate VIEs that were previously not consolidated. The VIEs we expect to consolidate include certain trusts that hold assets we lease. Consolidation of these VIEs will eliminate the lease accounting we now report for these assets and result in changes in our consolidated assets, debt and equity. Any changes in net income that occur as a result of the elimination of lease accounting and consolidation of VIEs will be offset through the recognition of either a regulatory asset or liability. Consolidation of these VIEs will also result in changes to our consolidated statements of cash flows related to each VIE's cash activity. We continue to evaluate the impact that consolidating these VIEs will have on our consolidated financial results. The changes to our consolidated assets, debt and equity may be material.

Recognition and Presentation of Other-Than-Temporary Impairments

In April 2009, FASB issued guidance that addresses the measurement and recognition of other-than-temporary impairments of investments in debt securities. The guidance also provides for changes in the presentation and disclosure requirements surrounding other-than-temporary impairments of investments in debt and equity securities. This guidance is effective for interim and annual reporting periods ending after June 15, 2009. We adopted this guidance effective April 1, 2009, without a material impact on our consolidated financial results.

Employers' Disclosures about Post-retirement Benefit Plan Assets

In December 2008, FASB issued guidance that requires enhanced disclosures about the plan assets of defined benefit pension and other post-retirement benefit plans. These disclosures include how investment allocation decisions are made, the factors pertinent to understanding investment policies and strategies, the fair value of each major category of plan assets for pension plans and other post-retirement benefit plans separately, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets and significant concentrations of risk within plan assets. We adopted this guidance effective December 15, 2009. See Notes 11 and 12 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans" and "Wolf Creek Employee Benefit Plans."

Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities

In June 2008, FASB issued guidance for determining whether instruments granted in share-based payment transactions are participating securities. The guidance provides that all outstanding unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents are participating securities and shall be included in the computation of EPS pursuant to the two-class method. This guidance is effective for fiscal years beginning after December 15, 2008, with retrospective application to prior periods. We adopted this guidance effective January 1, 2009. See "—Earnings Per Share" under Note 2 of the Notes to Condensed Consolidated Financial Statements, "Summary of Significant Accounting Policies."

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, FASB issued guidance that requires expanded disclosure to help investors better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows. The guidance amends and expands the disclosure requirements related to derivative instruments and hedging activities by requiring qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosure about fair value amounts of gains and losses on derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements. This guidance is effective for fiscal years beginning after November 15, 2008. We adopted this guidance effective January 1, 2009. See Note 4 of the Notes to Consolidated Financial Statements, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management."

Fair Value Measurements

In September 2006, FASB issued guidance that defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. This guidance is effective for fiscal years beginning after November 15, 2007, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We adopted the guidance for financial assets and liabilities recognized at fair value on a recurring basis effective January 1, 2008, and for non-financial assets and liabilities recognized at fair value on a nonrecurring basis effective January 1, 2009. The adoption of this guidance did not have a material impact on our consolidated financial results. See Note 4 of the Notes to Consolidated Financial Statements, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management."

In April 2009, FASB issued guidance on two separate fair value issues. Both of the releases are effective for interim and annual reporting periods ending after June 15, 2009, and we adopted both of them effective April 1, 2009. One of the releases provides guidance for determining fair value when the volume and level of activity for an asset or liability have significantly decreased and for identifying transactions that are not orderly. We adopted this guidance without a material impact on our consolidated financial results. The other release requires disclosures about the fair value of financial instruments in interim reporting periods as well as in annual financial statements. See Note 4 of the Notes to Consolidated Financial Statements, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management."

In September 2009, FASB issued guidance permitting entities to measure the fair value of certain investments on the basis of the net asset value per share of the investments and requiring additional disclosure about such fair value measurements. This guidance is effective for interim and annual periods ending after December 15, 2009. We adopted the guidance effective October 1, 2009, without a material impact on our consolidated financial results. See Note 4 of the Notes to Consolidated Financial Statements, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management."

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.

Market Price Risks

We engage in physical and financial trading activities 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 forward and futures contracts, options and swaps.

Prices in the wholesale power markets often are extremely volatile. This volatility impacts our cost of power purchased and our participation in energy trades. If we were unable to generate an adequate supply of electricity for our customers, we would attempt to purchase power from others. Such supplies are not always available. In addition, congestion on the transmission system can limit our ability to make purchases from, or sell into, the wholesale markets. The inability to make wholesale purchases may require that we interrupt or curtail services to our customers. 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 changes in market prices. Additional factors that affect our commodity price exposure are the quantity and availability of fuel used for generation and the quantity of electricity customers consume. The availability and deliverability of generating fuel, including fossil and nuclear fuels, can vary significantly from one period to the next. Our customers' electricity usage could also vary from year to year based on the weather or other factors. The loss of revenues or higher costs associated with such conditions could be material and adverse to our consolidated financial results. Our risk of loss is partially mitigated through the use of tariffs and contracts authorized by regulators that allow us to adjust our prices in response to changing costs.

Hedging Activity

In an effort to mitigate market risk associated with fuel procurement and energy marketing, we may use economic hedging arrangements to reduce our exposure to price changes. We may use physical contracts and financial derivative instruments to hedge the price of a portion of our anticipated fossil fuel needs or excess generation sales. 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.

Commodity Price Exposure

One way by which we manage and measure the market price risk exposure 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 2010. 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 markedly from assumptions. Accordingly, VaR may not accurately reflect our levels of exposures. The energy trading and market-based wholesale portfolio VaR amounts for 2009 and 2008 were as follows:

	2009	2008
	(In Thousands)	
High	$ 914	$ 1,660
Low	43	127
Average	280	983

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 exposure 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 have exposure to counterparty default risk with our retail, wholesale and energy marketing activities, including participation in RTOs. We maintain credit policies intended to reduce overall credit risk. We 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 rating agencies' assessments of our senior unsecured debt. If our senior unsecured debt ratings were to decrease or fall below investment grade, then the counterparties to the derivative instruments, pursuant to such provisions, could require us to post collateral 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, 2009, was $1.4 million, for which we had posted no collateral. If all credit-risk-related contingent features underlying these agreements had been triggered as of December 31, 2009, we would have been required to provide to our counterparties $0.1 million of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

Interest Rate Exposure

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 and utilizing various maturity dates. We may also use swaps or other financial instruments to manage our interest rate risk. 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 rate applicable to such debt over the remaining time the debt is outstanding.

We had approximately $366.0 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2009. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $3.6 million. As of December 31, 2009, we had $121.9 million of variable rate bonds insured by bond insurers. Prior to February 2008, interest rates payable under these bonds historically had been set through periodic auctions. Conditions in the credit markets over the past two years have caused a dramatic reduction in the demand for auction bonds, which has lead to failures in these 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 bond experience a decrease in their credit ratings, such event would most likely increase our borrowing costs as well. Furthermore, a decline in interest rates generally can serve to increase our pension and other post-retirement benefit obligations and affect investment returns.

Security Price Risk

We maintain trust funds, as required by the NRC and Kansas state laws, to fund certain costs of nuclear plant decommissioning. As of December 31, 2009, investments in the nuclear decommissioning trust fund were allocated 61% to equity securities, 29% to debt securities, 3% to real estate securities, 5% to commodities and 2% to cash and cash equivalents. The fair value of these funds was $112.3 million as of December 31, 2009, and $85.6 million as of December 31, 2008. Changes in interest rates and/or other market changes resulting in a 10% decrease in the value of the equity, debt and real estate securities and commodities would have resulted in an $11.1 million decrease in the value of the nuclear decommissioning trust fund as of December 31, 2009.

We also maintain a trust to fund non-qualified retirement benefits. As of December 31, 2009, these funds were comprised of 66% equity securities and 34% debt securities. The fair value of these funds was $34.6 million as of December 31, 2009, and $26.3 million as of December 31, 2008. Changes in interest rates and/or other market changes resulting in a 10% decrease in the value of the equity and debt securities would have resulted in a $3.5 million decrease in the value of this trust as of December 31, 2009.

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, debt and equity 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 allocation in relation to established policy targets. Our exposure to security price risk related to the nuclear decommissioning trust fund is, in part, mitigated because we are currently allowed to recover decommissioning costs in the prices we charge our customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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SCHEDULES OMITTED

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

I, III, IV, and V.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

We assessed the effectiveness of our internal control over financial reporting as of December 31, 2009. 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 believe that, as of December 31, 2009, 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
Shareholders 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, 2009, 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 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, 2009, 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, 2009 of the Company and our report dated February 25, 2010 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 25, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Shareholders 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, 2009 and 2008, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, 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 25, 2010 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 25, 2010

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

	As of December 31,	
	2009	2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,860	$ 22,914
Accounts receivable, net of allowance for doubtful accounts of $5,231 and $4,810, respectively	216,186	199,116
Inventories and supplies, net	193,831	204,297
Energy marketing contracts	33,159	131,647
Taxes receivable	45,200	36,462
Deferred tax assets	7,927	16,416
Prepaid expenses	11,830	33,419
Regulatory assets	97,220	79,783
Other	20,269	19,077
Total Current Assets	629,482	743,131
PROPERTY, PLANT AND EQUIPMENT, NET	5,771,740	5,533,521
OTHER ASSETS:		
Regulatory assets	758,538	872,487
Nuclear decommissioning trust	112,268	85,555
Energy marketing contracts	10,653	25,601
Other	242,802	182,964
Total Other Assets	1,124,261	1,166,607
TOTAL ASSETS	$7,525,483	$7,443,259
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 1,345	$ 146,366
Short-term debt	242,760	174,900
Accounts payable	112,211	195,683
Accrued taxes	46,931	44,008
Energy marketing contracts	39,161	104,622
Accrued interest	76,955	42,142
Regulatory liabilities	39,745	31,123
Other	123,370	133,565
Total Current Liabilities	682,478	872,409
LONG-TERM LIABILITIES:		
Long-term debt, net	2,490,734	2,192,538
Obligation under capital leases	109,300	117,909
Deferred income taxes	964,461	1,004,920
Unamortized investment tax credits	127,777	59,386
Deferred gain from sale-leaseback	108,532	114,027
Accrued employee benefits	433,561	526,177
Asset retirement obligations	119,519	95,083
Energy marketing contracts	210	2,262
Regulatory liabilities	100,963	91,934
Other	117,720	155,612
Total Long-Term Liabilities	4,572,777	4,359,848
COMMITMENTS AND CONTINGENCIES (See Notes 13 and 15)		
TEMPORARY EQUITY (See Note 11)	3,443	3,422
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 150,000,000 shares; issued and outstanding 109,072,000 shares and 108,311,135 shares, respectively	545,360	541,556
Paid-in capital	1,339,790	1,326,391
Retained earnings	360,199	318,197
Total Shareholders' Equity	2,266,785	2,207,580
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$7,525,483	$7,443,259

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

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

	Year Ended December 31,		
	2009	2008	2007
REVENUES	$ 1,858,231	$ 1,838,996	$ 1,726,834
OPERATING EXPENSES:			
Fuel and purchased power	534,864	694,348	544,421
Operating and maintenance	516,930	471,838	473,525
Depreciation and amortization	251,534	203,738	192,910
Selling, general and administrative	199,961	184,427	178,587
Total Operating Expenses	1,503,289	1,554,351	1,389,443
INCOME FROM OPERATIONS	354,942	284,645	337,391
OTHER INCOME (EXPENSE):			
Investment earnings (losses)	12,658	(10,453)	6,031
Other income	7,128	29,658	6,726
Other expense	(17,188)	(15,324)	(14,072)
Total Other Income (Expense)	2,598	3,881	(1,315)
Interest expense	157,360	106,450	103,883
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	200,180	182,076	232,193
Income tax expense	58,850	3,936	63,839
INCOME FROM CONTINUING OPERATIONS	141,330	178,140	168,354
Results of discontinued operations, net of tax	33,745	—	—
NET INCOME	175,075	178,140	168,354
Preferred dividends	970	970	970
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 174,105	$ 177,170	$ 167,384
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (see Note 2):			
Basic earnings available from continuing operations	$ 1.28	$ 1.69	$ 1.83
Discontinued operations, net of tax	0.30	—	—
Basic earnings per common share	$ 1.58	$ 1.69	$ 1.83
Diluted earnings available from continuing operations	$ 1.28	$ 1.69	$ 1.83
Discontinued operations, net of tax	0.30	—	—
Diluted earnings per common share	$ 1.58	$ 1.69	$ 1.83
Average equivalent common shares outstanding	109,647,689	103,958,414	90,675,511
DIVIDENDS DECLARED PER COMMON SHARE	$ 1.20	$ 1.16	$ 1.08

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

WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in Thousands)

	Year Ended December 31,		
	2009	2008	2007
NET INCOME	$ 175,075	$ 178,140	$ 168,354
OTHER COMPREHENSIVE INCOME (LOSS):			
Unrealized holding gain (loss) on marketable securities arising during the period	—	—	51
Minimum pension liability adjustment	—	—	—
Other comprehensive income, before tax	—	—	51
Income tax expense related to items of other comprehensive income	—	—	—
Other comprehensive income, net of tax	—	—	51
COMPREHENSIVE INCOME	$ 175,075	$ 178,140	$ 168,405

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

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

	Year Ended December 31,		
	2009	2008	2007
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$ 175,075	$ 178,140	$ 168,354
Discontinued operations, net of tax	(33,745)	—	—
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	251,534	203,738	192,910
Amortization of nuclear fuel	16,161	14,463	16,711
Amortization of deferred gain from sale-leaseback	(5,495)	(5,495)	(5,495)
Amortization of corporate-owned life insurance	22,116	18,920	13,693
Non-cash compensation	5,133	4,696	5,800
Net changes in energy marketing assets and liabilities	8,972	(7,018)	7,647
Accrued liability to certain former officers	2,296	(1,449)	931
Gain on sale of utility plant and property	—	(1,053)	—
Net deferred income taxes and credits	46,447	35,261	14,084
Stock-based compensation excess tax benefits	(448)	(561)	(1,058)
Allowance for equity funds used during construction	(5,031)	(18,284)	(4,346)
Changes in working capital items, net of acquisitions and dispositions:			
Accounts receivable	(17,159)	(3,331)	(15,926)
Inventories and supplies	10,466	(11,764)	(44,603)
Prepaid expenses and other	(10,635)	(52,615)	(72,212)
Accounts payable	(15,115)	(73,971)	59,488
Accrued taxes	30,493	27,938	(50,027)
Other current liabilities	13,572	(5,732)	(50,179)
Changes in other assets	73,784	29,389	(54,668)
Changes in other liabilities	(89,516)	(56,382)	65,712
Cash flows from operating activities	478,905	274,890	246,816
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(555,637)	(918,958)	(743,810)
Investment in corporate-owned life insurance	(17,724)	(18,720)	(18,793)
Purchase of securities within the nuclear decommissioning trust fund	(64,016)	(210,599)	(240,067)
Sale of securities within the nuclear decommissioning trust fund	61,096	221,613	238,414
Proceeds from investment in corporate-owned life insurance	1,748	27,320	544
Proceeds from sale of plant and property	—	4,295	—
Other investing activities	2,920	(11,388)	—
Investment in affiliated company	(818)	—	—
Proceeds from other investments	—	—	1,653
Cash flows used in investing activities	(572,431)	(906,437)	(762,059)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	67,860	(5,100)	20,000
Proceeds from long-term debt	347,507	544,715	322,284
Retirements of long-term debt	(196,821)	(101,311)	(25)
Repayment of capital leases	(10,190)	(9,820)	(5,729)
Borrowings against cash surrender value of corporate-owned life insurance	10,299	64,255	61,472
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(3,531)	(28,634)	(2,209)
Stock-based compensation excess tax benefits	448	561	1,058
Issuance of common stock, net	4,587	293,621	195,420
Cash dividends paid	(122,937)	(109,579)	(89,471)
Cash flows from financing activities	97,222	648,708	502,800
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 (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(19,054)	17,161	(12,443)
CASH AND CASH EQUIVALENTS:			
Beginning of period	22,914	5,753	18,196
End of period	$ 3,860	$ 22,914	$ 5,753

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

WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Dollars in Thousands)

	Cumulative preferred stock	Common stock	Paid-in capital	Retained earnings	Accumulated other comprehensive (loss) income	Total Shareholders' Equity
Balance at December 31, 2006	$ 21,436	$ 436,974	$ 916,605	$ 185,779	$ 101	$ 1,560,895
Net income	—	—	—	168,354	—	168,354
Issuance of common stock, net	—	40,342	165,623	—	—	205,965
Preferred dividends, net of retirements	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	(99,153)	—	(99,153)
Reclass to Temporary Equity	—	—	1,447	—	—	1,447
Amortization of restricted stock	—	—	5,116	—	—	5,116
Stock compensation and tax benefit	—	—	(3,692)	—	—	(3,692)
Unrealized gain on marketable securities	—	—	—	—	51	51
Adjustment to Retained Earnings – Uncertain Income Tax Positions	—	—	—	10,467	—	10,467
Balance at December 31, 2007	21,436	477,316	1,085,099	264,477	152	1,848,480
Net income	—	—	—	178,140	—	178,140
Issuance of common stock, net	—	64,240	239,316	—	—	303,556
Preferred dividends, net of retirements	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	(123,107)	—	(123,107)
Reclass to Temporary Equity	—	—	1,802	—	—	1,802
Amortization of restricted stock	—	—	3,941	—	—	3,941
Stock compensation and tax benefit	—	—	(3,767)	—	—	(3,767)
Adjustment to Retained Earnings – Pension and Other Post-retirement Benefit Plans	—	—	—	(495)	—	(495)
Adjustment to Retained Earnings – Fair Value Option	—	—	—	152	(152)	—
Balance at December 31, 2008	21,436	541,556	1,326,391	318,197	—	2,207,580
Net income	—	—	—	175,075	—	175,075
Issuance of common stock, net	—	3,804	10,569	—	—	14,373
Preferred dividends, net of retirements	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	(132,103)	—	(132,103)
Reclass to Temporary Equity	—	—	(20)	—	—	(20)
Amortization of restricted stock	—	—	4,524	—	—	4,524
Stock compensation and tax benefit	—	—	(1,674)	—	—	(1,674)
Balance at December 31, 2009	$ 21,436	$ 545,360	$ 1,339,790	$ 360,199	$ —	$ 2,266,785

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

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

We provide electric generation, transmission and distribution services to approximately 685,000 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. KGE owns a 47% interest in the Wolf Creek Generating Station (Wolf Creek), a nuclear power plant located near Burlington, Kansas. 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 and majority owned subsidiaries, reported as a single operating segment, for which we maintain controlling interests. Undivided interests in jointly-owned generation facilities are included on a proportionate basis. Intercompany accounts and transactions have been eliminated in consolidation. In our opinion, all adjustments, consisting only of normal recurring adjustments considered necessary for a fair presentation of the consolidated financial statements, have been included.

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 bad debts, inventories, valuation of commodity contracts, depreciation, unbilled revenue, investments, valuation of our energy marketing portfolio, intangible assets, forecasted fuel costs included in our retail energy cost adjustment (RECA) billed to customers, income taxes, pension and other post-retirement benefits, our asset retirement obligations (AROs) including the decommissioning of Wolf Creek, environmental issues, 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.

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,	
	2009	2008
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$ 369,877	$ 440,061
Amounts due from customers for future income taxes, net	183,667	193,997
Depreciation	82,541	85,104
Debt reacquisition costs	79,342	87,321
Ice storm costs	48,998	68,109
Asset retirement obligations	20,719	21,542
Wolf Creek outage	19,438	12,442
Disallowed plant costs	16,462	16,560
Retail energy cost adjustment	13,298	17,991
Other regulatory assets	21,416	9,143
Total regulatory assets	$ 855,758	$ 952,270
Regulatory Liabilities:		
Removal costs	$ 68,078	$ 50,051
Retail energy cost adjustment	27,488	456
Nuclear decommissioning	16,658	15,054
Fuel supply and electricity sale contracts	6,001	36,331
Ad valorem tax	5,604	7,347
Kansas tax credits	5,351	—
State Line purchased power	2,493	3,379
Other regulatory liabilities	9,035	10,439
Total regulatory liabilities	$ 140,708	$ 123,057

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 $359.0 million for pension and post-retirement benefit obligations; $10.1 million for the difference between pension and post-retirement benefits expense and the amount of such expense recognized in setting our prices; and $0.8 million for post-retirement expenses in excess of amounts paid in 2009. During 2010, we will amortize to expense approximately $29.0 million of the benefit obligation. The post-retirement expenses are recovered over a period of five years. We do not earn a return on this asset.

- **Amounts due from customers for future income taxes, net:** In accordance with various orders, we have reduced our prices to reflect the tax benefits associated with certain 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 tax benefits reverse in future periods. As a result, we have recorded a $220.8 million regulatory asset, on which we do not earn a return. Partially offsetting this asset is a $37.1 million regulatory liability for our obligation to customers for taxes recovered in earlier periods when corporate tax rates were higher than the current tax rates. This benefit will be returned to customers as these temporary differences reverse in future periods. The 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.

- **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 recover 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.

- **Ice storm costs:** We accumulated and deferred for future recovery costs related to restoring our electric transmission and distribution systems from damage sustained during unusually damaging storms. We recover these costs over periods ranging from three to five years and 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.

- **Wolf Creek outage:** Wolf Creek incurs a refueling and maintenance outage approximately every 18 months. The expenses associated with these maintenance and refueling outages are deferred and amortized over the period between such planned outages. 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.

- **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 of which had a unique RECA and 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.

- **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, most of which range from three to five years.

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

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

- **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 of which had a unique RECA and a separate cost of fuel. This resulted in us simultaneously reporting both a regulatory asset and a regulatory liability for this item.

- **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 our ARO and the fair value of the assets held in a decommissioning trust. See Note 5, "Financial Investments and Trading Securities" and Note 14, "Asset Retirement Obligations," for information regarding our nuclear decommissioning trust fund and our ARO.

- **Fuel supply and electricity sale contracts:** We use fair value accounting for some of our fuel supply and electricity sale contracts. This represents the non-cash net gain position on fuel supply and electricity sale 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.

- **Kansas tax credits:** Represents Kansas tax credits on investments in utility plant. Amounts are credited to customers over the lives of the utility plant giving rise to the tax credits.

- **State Line purchased power:** Represents amounts received from customers in excess of costs incurred under Westar Energy's purchased power agreement with Westar Generating, Inc., a wholly-owned subsidiary.

- **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, most of which range from one to five years.

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.

Inventories and Supplies

We state inventories and supplies at average cost.

Property, Plant and Equipment

We record the value of property, plant and equipment 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 to other income (for equity funds) and interest expense (for borrowed funds) the amount of AFUDC capitalized as construction cost on the accompanying consolidated statements of income as follows:

	Year Ended December 31,		
	2009	2008	2007
		(Dollars In Thousands)	
Borrowed funds	$ 4,857	$ 20,536	$ 13,090
Equity funds	5,031	18,284	4,346
Total	$ 9,888	$ 38,820	$ 17,436
Average AFUDC Rates	4.2%	6.4%	6.6%

We charge maintenance costs and replacement of minor items of property to expense as incurred, except for maintenance costs incurred for our refueling 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 planned refueling outages. Normally, 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 2009, 2.6% in 2008 and 2.7% in 2007.

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

	Years
Fossil fuel generating facilities	7 to 69
Nuclear fuel generating facility	40 to 60
Wind generating facilities	19 to 20
Transmission facilities	15 to 65
Distribution facilities	21 to 70
Other	5 to 35

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 $22.9 million as of December 31, 2009, and $29.3 million as of December 31, 2008. Spent nuclear fuel charged to fuel and purchased power expense was $20.1 million in 2009, $18.3 million in 2008 and $21.7 million in 2007.

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,	
	2009	2008
	(In Thousands)	
Cash surrender value of policies	$1,209,304	$1,156,457
Borrowings against policies	(1,073,544)	(1,066,776)
Corporate-owned life insurance, net	$ 135,760	$ 89,681

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. Death benefits were approximately $3.8 million in 2009, $9.5 million in 2008 and $2.4 million in 2007.

Revenue Recognition – Energy 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.

The accuracy of 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 had estimated unbilled revenue of $56.6 million as of December 31, 2009, and $47.7 million as of December 31, 2008. The increases reflect our price increases as discussed in Note 3, "Rate Matters and Regulation."

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 sale 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 resulting unrealized gains and losses as energy marketing long-term or short-term assets and 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.

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 for carryforwards of 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 gain income 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. We report the effect of a change in the valuation allowance in the current period tax expense.

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 exposures. 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 them in our consolidated statements of income.

Earnings Per Share

Effective January 1, 2009, we adopted guidance issued by the Financial Accounting Standards Board (FASB) for determining whether instruments granted in share-based payment transactions are participating securities. According to the provisions of this guidance, we have participating securities related to 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). We adopted this guidance with retrospective application to prior periods which resulted in a decrease in basic and diluted EPS for the year ended December 31, 2008, from $1.70 per share as previously reported in our 2008 Form 10-K to $1.69 per share as reported in this Form 10-K. Basic EPS for the year ended December 31, 2007, also decreased from $1.85 per share as previously reported in our 2007 Form 10-K to $1.83 per share as reported in this Form 10-K.

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 the exercise of all outstanding stock options issued pursuant to the terms of our stock-based compensations plans. We compute the dilutive effect of shares issuable under our stock-based compensation plans using the treasury stock method.

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

	Year Ended December 31,		
	2009	2008	2007
	(Dollars In Thousands, Except Per Share Amounts)		
Income from continuing operations	$ 141,330	$ 178,140	$ 168,354
Less: Preferred dividends	970	970	970
Income from continuing operations allocated to RSUs	541	1,346	1,863
Income from continuing operations attributable to common stock	$ 139,819	$ 175,824	$ 165,521
Weighted average equivalent common shares outstanding – basic	109,647,689	103,958,414	90,675,511
Effect of dilutive securities:			
Employee stock options	481	728	952
Weighted average equivalent common shares outstanding – diluted (a)	109,648,170	103,959,142	90,676,463
Earnings from continuing operations per common share, basic and diluted	$ 1.28	$ 1.69	$ 1.83

(a) We did not have any antidilutive shares for the year ended December 31, 2009. For the years ended December 31, 2008, and December 31, 2007, potentially dilutive shares not included in the denominator because they are antidilutive totaled 21,300 shares and 74,890 shares, respectively.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2009	2008	2007
		(In Thousands)	
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$ 144,964	$ 102,865	$ 84,291
Income taxes, net of refunds	(7,870)	(34,905)	74,970
NON-CASH INVESTING TRANSACTIONS:			
Jeffrey Energy Center 8% leasehold interest	—	—	118,538
Other property, plant and equipment additions	21,614	106,219	100,039
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and compensation plans	12,168	11,263	10,553
Capital lease for Jeffrey Energy Center 8% leasehold interest	—	—	118,538
Other assets acquired through capital leases	2,818	4,583	3,228

New Accounting Pronouncements

We prepare our consolidated financial statements in accordance with GAAP for the United States of America. To address current issues in accounting, regulatory bodies have issued the following new accounting pronouncements that may affect our accounting and/or disclosure.

FASB Codification

In June 2009, FASB approved its Accounting Standards Codification (Codification) as the exclusive authoritative reference for U.S. GAAP to be applied by nongovernmental entities. Securities and Exchange Commission (SEC) rules and interpretive releases are still considered authoritative GAAP for SEC registrants. The Codification, which changes the referencing of accounting standards, is effective for interim and annual reporting periods ending after September 15, 2009. We adopted the Codification effective July 1, 2009, without a material impact on our consolidated financial results.

Variable Interest Entities

In June 2009, FASB issued guidance that amends the consolidation guidance for variable interest entities (VIEs). The amended guidance requires a qualitative assessment rather than a quantitative assessment in determining the primary beneficiary of a VIE and significantly changes the consolidation criteria to be considered in determining the primary beneficiary. Pursuant to the amended guidance, there is no exclusion, or "grandfathering," of VIEs that were not consolidated under prior guidance. This amended guidance is effective for annual reporting periods beginning after November 15, 2009. We adopted the guidance effective January 1, 2010, and, as a result, expect to consolidate VIEs that were previously not consolidated. The VIEs we expect to consolidate include certain trusts that hold assets we lease. Consolidation of these VIEs will eliminate the lease accounting we now report for these assets and result in changes in our consolidated assets, debt and equity. Any changes in net income that occur as a result of the elimination of lease accounting and consolidation of VIEs will be offset through the recognition of either a regulatory asset or liability. Consolidation of these VIEs will also result in changes to our consolidated statements of cash flows related to each VIE's cash activity. We continue to evaluate the impact that consolidating these VIEs will have on our consolidated financial results. The changes to our consolidated assets, debt and equity may be material.

Recognition and Presentation of Other-Than-Temporary Impairments

In April 2009, FASB issued guidance that addresses the measurement and recognition of other-than-temporary impairments of investments in debt securities. The guidance also provides for changes in the presentation and disclosure requirements surrounding other-than-temporary impairments of investments in debt and equity securities. This guidance is effective for interim and annual reporting periods ending after June 15, 2009. We adopted this guidance effective April 1, 2009, without a material impact on our consolidated financial results.

Employers' Disclosures about Post-retirement Benefit Plan Assets

In December 2008, FASB issued guidance that requires enhanced disclosures about the plan assets of defined benefit pension and other post-retirement benefit plans. These disclosures include how investment allocation decisions are made, the factors pertinent to understanding investment policies and strategies, the fair value of each major category of plan assets for pension plans and other post-retirement benefit plans separately, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets and significant concentrations of risk within plan assets. We adopted this guidance effective December 15, 2009. See Notes 11 and 12, "Employee Benefit Plans" and "Wolf Creek Employee Benefit Plans."

Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities

In June 2008, FASB issued guidance for determining whether instruments granted in share-based payment transactions are participating securities. The guidance provides that all outstanding unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents are participating securities and shall be included in the computation of EPS pursuant to the two-class method. This guidance is effective for fiscal years beginning after December 15, 2008, with retrospective application to prior periods. We adopted this guidance effective January 1, 2009. See "—Earnings Per Share" above.

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, FASB issued guidance that requires expanded disclosure to help investors better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows. The guidance amends and expands the disclosure requirements related to derivative instruments and hedging activities by requiring qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosure about fair value amounts of gains and losses on derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements. This guidance is effective for fiscal years beginning after November 15, 2008. We adopted this guidance effective January 1, 2009. See Note 4, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management."

Fair Value Measurements

In September 2006, FASB issued guidance that defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. This guidance is effective for fiscal years beginning after November 15, 2007, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We adopted the guidance for financial assets and liabilities recognized at fair value on a recurring basis effective January 1, 2008, and for non-financial assets and liabilities recognized at fair value on a nonrecurring basis effective January 1, 2009. The adoption of this guidance did not have a material impact on our consolidated financial results. See Note 4, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management."

In April 2009, FASB issued guidance on two separate fair value issues. Both of the releases are effective for interim and annual reporting periods ending after June 15, 2009, and we adopted both of them effective April 1, 2009. One of the releases provides guidance for determining fair value when the volume and level of activity for an asset or liability have significantly decreased and for identifying transactions that are not orderly. We adopted this guidance without a material impact on our consolidated financial results. The other release requires disclosures about the fair value of financial instruments in interim reporting periods as well as in annual financial statements. See Note 4, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management."

In September 2009, FASB issued guidance permitting entities to measure the fair value of certain investments on the basis of the net asset value per share of the investments and requiring additional disclosure about such fair value measurements. This guidance is effective for interim and annual periods ending after December 15, 2009. We adopted the guidance effective October 1, 2009, without a material impact on our consolidated financial results.

3. RATE MATTERS AND REGULATION

KCC Proceedings

On January 27, 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with our investments in natural gas and wind generation facilities that were not included in the price increase approved by the KCC in its January 21, 2009, order discussed below. The new prices were effective February 2010 and are expected to increase our annual retail revenues by $17.1 million.

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. At the time of a future rate case, we expect to amortize such regulatory asset or liability as part of resetting base rates.

On May 29, 2009, the KCC issued an order allowing us to adjust our prices to include costs associated with environmental investments made in 2008. This change went into effect on June 1, 2009, and is expected to increase our annual retail revenues by $32.5 million.

On March 6, 2009, the KCC issued an order allowing us to adjust our prices to include updated transmission costs. This change went into effect on March 13, 2009, and is expected to increase our annual retail revenues by $31.8 million.

On January 21, 2009, the KCC issued an order expected to increase our annual retail prices by $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 became effective on February 3, 2009.

On September 18, 2008, the KCC issued an order allowing us to adjust our prices to include updated transmission costs. This change was expected to increase our annual retail revenues by $6.1 million.

On May 29, 2008, the KCC issued an order allowing us to adjust our prices to include costs associated with environmental investments made in 2007. This change went into effect on June 1, 2008, and was expected to increase our annual retail revenues by $22.0 million.

FERC Proceedings

Requests for Changes in Rates

On October 15, 2009, we filed our updated transmission formula rate which includes projected 2010 transmission capital expenditures and operating costs. Our updated transmission formula rate was effective January 1, 2010, and is expected to increase our annual transmission revenues by $16.8 million.

In July and August 2009, the Federal Energy Regulatory Commission (FERC) approved our requests to implement a cost-based formula rate for two of our wholesale customers. The use of a cost-based formula rate allows us to adjust our prices to reflect changes in our cost of service. On January 12, 2010, FERC issued an order accepting our request to implement a cost-based formula rate similar to that described above that would be applicable for sales to other wholesale customers. The cost-based formula rate was effective as of December 1, 2009.

On December 2, 2008, FERC issued an order approving a settlement of our transmission formula rate that allows us to include our anticipated transmission capital expenditures for the current year in our transmission formula rate, subject to true up. In addition to the true up, we expect to update our transmission formula rate in January of each year to reflect changes in our projected operating costs and investments.

On March 24, 2008, FERC issued an order that granted our requested incentives of an additional 100 basis points above the base allowed return on equity and a 15-year accelerated recovery for an approximately 100 mile, 345 kilovolt transmission line that will run from near Wichita, Kansas, to near Salina, Kansas. We completed construction of the first segment of this line in December 2008 and expect the second segment to be completed in 2010.

In December 2007, FERC issued an order accepting proposed changes in the capital structure used in our transmission formula rate. This rate change was effective June 1, 2007, and the resulting customer refunds have been completed.

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

Values of Financial and Derivative Instruments

We carry 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.

Most of our 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 our investments is comprised of private equity investments, debt or 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 initially measured at cost or at the value derived from subsequent financing with adjustments when actual performance differs significantly from expected performance; when market, economic or company-specific conditions change; or when other news or events have a material impact on the security. Debt investments for which we apply unobservable information to measure fair value are principally invested in mortgage-backed securities and collateralized loans. These investments are measured at fair value using subjective estimates such as projected cash flows and future interest rates. Real estate securities are measured at fair value using market discount rates, projected cash flows and the estimated value into perpetuity.

Energy marketing contracts can be exchange-traded or 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, management estimations are a significant input. See "—Recurring Fair Value Measurements" and "—Derivative Instruments" below for additional information.

We measure fair value based on information available as of the measurement date. The following table provides the carrying values and measured fair values of our financial instruments as of December 31, 2009 and 2008.

	Carrying Value		Fair Value	
	As of December 31,			
	2009	2008	2009	2008
	(In Thousands)			
Fixed-rate debt, net of current maturities (a)	$2,373,723	$2,024,178	$2,528,456	$1,749,123

(a) This amount does not include an equipment financing loan of $1.4 million and $2.7 million in 2009 and 2008, respectively.

Recurring Fair Value Measurements

GAAP establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring assets and liabilities at fair value. 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 either 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 fuel supply contracts.

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, 2009	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Energy Marketing Contracts	$ 7,310	$ 17,071	$ 19,431	$ 43,812
Nuclear Decommissioning Trust:				
Domestic equity	34,961	5,317	2,262	42,540
International equity	1,208	24,736	—	25,944
Core bonds	16,082	5,524	—	21,606
High-yield bonds	5,579	—	5,741	11,320
Real estate securities	—	—	3,635	3,635
Commodities	5,563	—	—	5,563
Cash equivalents	1,660	—	—	1,660
Total Nuclear Decommissioning Trust	65,053	35,577	11,638	112,268
Trading Securities:				
Domestic equity	—	18,344	—	18,344
International equity	—	4,422	—	4,422
Core bonds	—	11,853	—	11,853
Total Trading Securities	—	34,619	—	34,619
Total Assets Measured at Fair Value	$ 72,363	$ 87,267	$ 31,069	$ 190,699
Liabilities:				
Energy Marketing Contracts	$ 8,964	$ 15,286	$ 15,121	$ 39,371

As of December 31, 2008	Level 1	Level 2	Level 3	Total
Assets:				
Energy Marketing Contracts	$ 1,600	$ 104,821	$ 50,827	$ 157,248
Nuclear Decommissioning Trust:				
Domestic equity	31,139	3,606	2,006	36,751
International equity	736	16,904	—	17,640
Core bonds	8,535	5,667	—	14,202
High-yield bonds	4,087	4,347	—	8,434
Real estate securities	—	—	6,028	6,028
Commodities	1,459	—	—	1,459
Cash equivalents	1,041	—	—	1,041
Total Nuclear Decommissioning Trust	46,997	30,524	8,034	85,555
Trading Securities:				
Domestic equity	9,156	—	—	9,156
International equity	4,264	—	—	4,264
Core bonds	—	9,503	—	9,503
Total Trading Securities	13,420	9,503	—	$ 22,923
Total Assets Measured at Fair Value	$ 62,017	$ 144,848	$ 58,861	$ 265,726
Liabilities:				
Energy Marketing Contracts	$ 1,594	$ 99,004	$ 6,286	$ 106,884

We do not offset the fair value of energy marketing contracts executed with the same counterparty. As of December 31, 2009, we have recorded $0.3 million for our right to reclaim cash collateral and $1.8 million for our obligation to return cash collateral. As of December 31, 2008, we had recorded $5.1 million for our right to reclaim cash collateral and $4.5 million for our obligation to return cash collateral.

The following table provides a reconciliation of assets and liabilities measured at fair value using significant level 3 inputs for the years ended December 31, 2009 and 2008.

	Energy Marketing Contracts, net	Nuclear Decommissioning Trust Domestic Equity	Nuclear Decommissioning Trust High-yield Bonds	Nuclear Decommissioning Trust Real Estate Securities	Net Balance
			(In Thousands)		
Balance as of December 31, 2008	$ 44,541	$ 2,006	$ —	$ 6,028	$ 52,575
Total realized and unrealized gains (losses) included in:					
Earnings (a)	3,060	—	—	—	3,060
Regulatory assets	(15,382) (b)	—	—	—	(15,382)
Regulatory liabilities	(22,750) (b)	(39)	1,134	(2,393)	(24,048)
Purchases, issuances and settlements	(5,159)	295	4,607 (c)	—	(257)
Balance as of December 31, 2009	$ 4,310	$ 2,262	$ 5,741	$ 3,635	$ 15,948
Balance as of January 1, 2008	$ 41,141	$ 1,251	$ —	$ —	$ 42,392
Total realized and unrealized gains (losses) included in:					
Earnings (a)	(1,454)	—	—	—	(1,454)
Regulatory liabilities	12,289 (b)	(88)	—	28	12,229
Purchases, issuances and settlements	(7,435)	843	—	6,000	(592)
Balance as of December 31, 2008	$ 44,541	$ 2,006	$ —	$ 6,028	$ 52,575

(a) Unrealized and realized gains and losses included in earnings resulting from energy marketing activities are reported in revenues. Unrealized and realized gains and losses resulting from trading securities are included in other income.
(b) Includes changes in the fair value of certain fuel supply and electricity sale contracts.
(c) We used proceeds from the sale of certain debt investments measured at fair value using level 2 inputs to purchase different debt investments using significant level 3 unobservable inputs to measure at fair value.

A portion of the gains and losses contributing to changes in net assets in the above table is unrealized. The following table summarizes the unrealized gains and losses we recorded on our consolidated financial statements during the years ended December 31, 2009 and 2008, attributed to level 3 assets and liabilities still held as of December 31, 2009 and 2008, respectively.

	Year Ended December 31, 2009				
	Energy Marketing Contracts, net	Nuclear Decommissioning Trust: Domestic Equity	Nuclear Decommissioning Trust: High-yield Debt	Nuclear Decommissioning Trust: Real Estate Securities	Net Balance
			(In Thousands)		
Total unrealized gains (losses) included in:					
Earnings (a)	$ (474)	$ —	$ —	$ —	$ (474)
Regulatory assets	(8,545) (b)	—	—	—	(8,545)
Regulatory liabilities	(9,634) (b)	(39)	1,134	(2,497)	(11,036)
Total	$ (18,653)	$ (39)	$ 1,134	$ (2,497)	$ (20,055)
	Year Ended December 31, 2008				
Total unrealized gains (losses) included in:					
Earnings (a)	$ 2,842	$ —	$ —	$ —	$ 2,842
Regulatory assets	—	—	—	—	—
Regulatory liabilities	15,460 (b)	—	—	—	15,460
Total	$ 18,302	$ —	$ —	$ —	$ 18,302

(a) Unrealized gains and losses included in earnings resulting from energy marketing activities are reported in revenues. Unrealized gains and losses resulting from trading securities are reported in other income.

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

Certain investments in the nuclear decommissioning trust and all of our trading securities do not have a readily determinable fair value and are either investment companies or follow accounting guidance consistent with investment companies. In certain situations these investments may have redemption restrictions. The following table provides further information on these investments.

	Fair Value as of December 31, 2009	Unfunded Commitments	Redemption Frequency	Length of Settlement
		(In thousands)		
Nuclear Decommissioning Trust:				
Domestic equity	$ 7,579	$ 3,111	(a)	(a)
International equity	24,736	—	Monthly	11 – 18 days
Core bonds	5,524	—	Upon Notice	5 days
High-yield bonds	5,741	—	Upon Notice	3 days
Real estate securities (b)	3,635	—	Quarterly	60 days
Total Nuclear Decommissioning Trust	$ 47,215	$ 3,111		
Trading Securities:				
Domestic equity	$ 18,344	$ —	Upon Notice	1 day
International equity	4,422	—	Upon Notice	1 day
Core bonds	11,853	—	Upon Notice	1 day
Total Trading Securities	34,619	—		
Total	$ 81,834	$ 3,111		

(a) About 30% of the fair value is in long-term private equity funds that do not permit early withdrawal. The funds may begin liquidating in about 6 to 11 years unless the terms of the investments are extended. Our investments in these funds cannot be withdrawn until the underlying investments have been liquidated which may take years from the date of initial liquidation. The remaining 70% of the fair value permits liquidation upon notice and settles in three days.

(b) Due to recent volatility in real estate markets, we are unable to liquidate this investment as of the measurement date. It is unknown how long this restriction will persist.

Nonrecurring Fair Value Measurements

Wolf Creek files a nuclear decommissioning study with the KCC every three years. In 2009, we recorded a $20.3 million increase in our ARO to reflect revisions to the estimated costs to decommission Wolf Creek. The increase in the ARO is measured at fair value. The fair value of the ARO is measured by estimating the cost to decommission Wolf Creek at the end of its life then discounting that value at a risk- and inflation-adjusted rate. To determine the cost to decommission Wolf Creek at the end of its life, we must estimate the cost of basic inputs such as labor, energy, materials and burial, and the probability that costs may change. 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. Due to the significant unobservable inputs required in our measurement, we have determined that this ARO is a level 3 liability in the fair value hierarchy.

Derivative Instruments

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, including futures contracts, options and swaps, and we trade energy commodity contracts.

We classify 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 sale 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. We do not hold derivative instruments that are designated as hedging instruments. The following table presents the fair value of derivative instruments reflected on our consolidated balance sheet.

Commodity Derivatives Not Designated as Hedging Instruments as of December 31, 2009

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	$	33,159	Energy marketing contracts	$	39,161
Other assets:			Other liabilities:		
Energy marketing contracts		10,653	Energy marketing contracts		210
Total	$	43,812	Total	$	39,371

The following table presents how changes in the fair value of commodity derivative instruments affected our consolidated financial statements for the year ended December 31, 2009.

Location	Net Gain		Net Loss	
	(In Thousands)			
Revenues increase	$	7,790	$	—
Regulatory assets increase		—		7,064
Regulatory liabilities decrease				30,330

As of December 31, 2009, we had under contract the following energy-related products.

	Unit of Measure	Net Quantity
Electricity	MWh	4,147,800
Natural Gas	MMBtu	648,000
Coal	Ton	3,500,000

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 adverse 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, diesel and oil, to operate our plants and occasionally purchase power to meet customer demand. We are exposed to market risks from commodity price changes for electricity and other energy-related products and interest rates that could affect our consolidated financial results including cash flows. We manage our exposure to these market risks through our regular operating and financing activities and, when we deem appropriate, we economically hedge a portion of these risks through the use of derivative financial instruments for non-trading purposes.

Factors that affect our commodity price exposure are the quantity and availability of fuel used for generation 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 exposure is also affected by our nuclear plant refueling schedule. Our customers' electricity usage also varies based on weather, the economy and other factors.

The wholesale power and fuel markets are volatile which impacts our costs of purchased power and our participation in energy trades. We trade various types of fuel primarily to reduce exposure related to the volatility of commodity prices and a significant portion of our coal requirements is purchased under long-term contracts. 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.

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 constraint and other risks. Declines in the creditworthiness of our counterparties could have a material adverse 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 rating agencies' assessments 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 such provisions, could require us to post collateral 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, 2009, was $1.4 million, for which we had posted no collateral. If all credit-risk-related contingent features underlying these agreements had been triggered as of December 31, 2009, we would have been required to provide to our counterparties $0.1 million of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

5. FINANCIAL INVESTMENTS AND TRADING SECURITIES

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

Trading Securities

We have debt and equity investments in a trust used to fund retirement benefits that we classify as trading securities. We include any unrealized gains or losses on these securities in investment earnings on our consolidated statements of income. There was an unrealized gain of $11.3 million as of December 31, 2009, an unrealized loss of $9.5 million as of December 31, 2008, and an unrealized gain of $2.8 million as of December 31, 2007.

Available-for-Sale Securities

We hold investments in debt and equity securities in a trust fund 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, 2009 and 2008. At December 31, 2009, investments in the nuclear decommissioning trust fund were allocated 61% to equity securities, 29% to debt securities, 3% to real estate, 5% to commodities and 2% to cash and cash equivalents. Investments in debt securities are limited to funds which invest principally in U.S. government and agency securities, municipal bonds, corporate securities or foreign debt. As of December 31, 2009, the fair value of the debt securities in the nuclear decommissioning trust fund was $32.9 million entirely held in closed end funds, bond mutual funds and indexed bond funds.

Using the specific identification method to determine cost, we realized a $7.8 million and $20.1 million loss in 2009 and 2008, respectively, and a $5.7 million gain in 2007 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.

The following table presents the costs and fair values of investments in the nuclear decommissioning trust fund as of December 31, 2009 and 2008.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In Thousands)		
2009:				
Equity securities	$ 59,662	$ 12,015	$ (3,193)	$ 68,484
Debt securities	32,009	1,377	(460)	32,926
Real estate	6,206	—	(2,571)	3,635
Commodities	5,895	—	(332)	5,563
Cash equivalents	1,660	—	—	1,660
Total	$105,432	$ 13,392	$ (6,556)	$ 112,268
2008:				
Equity securities	$ 68,534	$ 2,308	$(16,451)	$ 54,391
Debt securities	25,598	6	(2,968)	22,636
Real estate	6,102	—	(74)	6,028
Commodities	2,511	—	(1,052)	1,459
Cash equivalents	1,041	—	—	1,041
Total	$103,786	$ 2,314	$(20,545)	$ 85,555

The following table presents the fair value and the gross unrealized losses of the available-for-sale securities held in the nuclear decommissioning trust 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, 2009.

	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)			
Equity securities	$ 4,321	$ (381)	$ 16,314	$ (2,812)	$ 20,635	$ (3,193)
Debt securities			5,579	(460)	5,579	(460)
Real estate	40	(16)	3,595	(2,555)	3,635	(2,571)
Commodities			5,563	(332)	5,563	(332)
Total	$ 4,361	$ (397)	$ 31,051	$ (6,159)	$ 35,412	$ (6,556)

6. PROPERTY, PLANT AND EQUIPMENT

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

	As of December 31,	
	2009	2008
	(In Thousands)	
Electric plant in service	$ 8,057,793	$ 7,182,589
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,370,805)	(3,249,007)
	5,489,306	4,735,900
Construction work in progress	214,705	733,816
Nuclear fuel, net	67,729	63,771
Net utility plant	5,771,740	5,533,487
Non-utility plant in service	—	34
Net property, plant and equipment	$ 5,771,740	$ 5,533,521

We recorded depreciation expense on property, plant and equipment of $228.6 million in 2009, $180.8 million in 2008 and $170.0 million in 2007.

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 interest in these facilities as of December 31, 2009, is shown in the table below.

	Our Ownership as of December 31, 2009					
	In-Service Dates	Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percentage
			(Dollars in Thousands)			
La Cygne unit 1 (a)................	June 1973	$ 285,895	$ 140,125	$ 18,904	368	50
Jeffrey unit 1 (a)	July 1978	481,397	185,928	3,262	665	92
Jeffrey unit 2 (a)	May 1980	442,151	178,112	31,579	667	92
Jeffrey unit 3 (a)	May 1983	662,638	231,863	306	659	92
Wolf Creek (b)........................	Sept. 1985	1,458,616	703,312	43,431	545	47
State Line (c)	June 2001	115,321	36,554	33	199	40
Total		$ 3,446,018	$ 1,475,894	$ 97,515	3,103	

(a) Jointly owned with Kansas City Power & Light Company (KCPL).
(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, as well as such expenses for a 50% undivided interest in La Cygne Generating Station (La Cygne) unit 2 sold and leased back to KGE in 1987, representing 341 megawatts (MW) of capacity. Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

In 2007, we purchased an 8% leasehold interest in Jeffrey Energy Center and assumed the related lease obligation. We recorded a capital lease of $118.5 million related to this transaction. This increased our interest in Jeffrey Energy Center to 92%. Amounts presented above do not include this capital lease or related depreciation.

8. SHORT-TERM DEBT

On February 15, 2008, FERC granted our request to issue short-term securities and pledge KGE mortgage bonds in order to increase the size of Westar Energy's revolving credit facility from $500.0 million to $750.0 million. On February 22, 2008, a syndicate of banks in the credit facility increased their commitments to $750.0 million in the aggregate with $730.0 million of the commitments terminating on March 17, 2012, and the remaining $20.0 million of commitments terminating on March 17, 2011.

Lehman Brothers Commercial Paper, Inc. (Lehman Brothers) was the participating lender with respect to the $20.0 million commitment terminating on March 17, 2011. On October 5, 2008, Lehman Brothers filed for bankruptcy protection. Under terms of the credit facility, we have the right to replace Lehman Brothers should another lender or lenders be willing to replace the $20.0 million commitment. To date, we have elected not to seek a replacement lender. As a result, until such time as we seek and locate a replacement lender or lenders, the revolving credit facility is limited to $730.0 million.

The weighted average interest rate on our borrowings under the revolving credit facility was 0.58% and 0.88% as of December 31, 2009, and December 31, 2008, respectively. As of February 17, 2010, $228.1 million had been borrowed and an additional $23.9 million of letters of credit had been issued under the revolving credit facility.

Additional information regarding our short-term borrowings is as follows.

	As of December 31,	
	2009	2008
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$200,547	$270,756
Weighted daily average interest rates during the year, excluding fees	0.76%	3.31%

Our interest expense on short-term debt was $2.2 million in 2009 and $9.7 million in 2008 and 2007.

9. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

	As of December 31, 2009	As of December 31, 2008
	(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, 0.48% as of December 31, 2009; 2.75% as of December 31, 2008	45,000	45,000
Variable due 2032, 0.54% as of December 31, 2009; 2.31% as of December 31, 2008	30,500	30,500
5.00% due 2033	57,760	58,215
	133,260	133,715
Other long-term debt:		
4.36% equipment financing loan due 2011	1,406	2,694
7.125% unsecured senior notes due 2009	—	145,078
	1,406	147,772
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	—
	625,000	325,000
Pollution control bond series:		
5.10% due 2023	13,463	13,463
Variable due 2027, 0.64% as of December 31, 2009; 1.95% as of December 31, 2008	21,940	21,940
5.30% due 2031	108,600	108,600
5.30% due 2031	18,900	18,900
Variable due 2032, 0.64% as of December 31, 2009; 1.95% as of December 31, 2008	14,500	14,500
Variable due 2032, 0.64% as of December 31, 2009; 1.95% as of December 31, 2008	10,000	10,000
4.85% due 2031	50,000	50,000
Variable due 2031, 1.647% as of December 31, 2008	—	50,000
5.60% due 2031	50,000	50,000
6.00% due 2031	50,000	50,000
5.00% due 2031	50,000	—
	387,403	387,403
Total long-term debt	2,497,069	2,343,890
Unamortized debt discount (a)	(4,990)	(4,986)
Long-term debt due within one year	(1,345)	(146,366)
Long-term debt, net	$2,490,734	$2,192,538

(a) We amortize debt discount to interest expense over the term of the respective issue.

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 in June 2009, 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, 2009, based on an assumed interest rate of 5.875%, approximately $350.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage, except in connection with certain refundings. As of December 31, 2009, approximately $550.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

As of December 31, 2009, we had $121.9 million of variable rate, tax-exempt bonds. Prior to February 2008, interest rates payable under these bonds had historically been set by auctions, which occurred every 35 days. Since then, auctions for these bonds have failed, resulting in alternative index-based interest rates for these bonds of between less than 1% and 14%. On July 31, 2008, the KCC approved our request for authority permitting us to remarket or refund all or part of these auction rate bonds. On each of October 15, 2009, October 10, 2008, and August 26, 2008, KGE refinanced $50.0 million of auction rate bonds at fixed interest rates of 5.00%, 6.00% and 5.60%, respectively, all with maturity dates of June 1, 2031. We continue to monitor the credit markets and evaluate our options with respect to the remaining auction rate bonds.

On August 3, 2009, we 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. We received net proceeds of $297.5 million.

On November 25, 2008, Westar Energy issued $300.0 million principal amount of first mortgage bonds at a discount yielding 8.750%, bearing stated interest at 8.625% and maturing on December 1, 2018. We received net proceeds of $295.6 million.

On May 15, 2008, KGE issued $150.0 million principal amount of first mortgage bonds in a private placement transaction with $50.0 million of the principal amount bearing interest at 6.15% and maturing on May 15, 2023, and $100.0 million bearing interest at 6.64% and maturing on May 15, 2038.

In January 2008, we increased the size of our 36-month equipment financing loan agreement to $3.9 million for computer equipment purchases made in 2008. As of December 31, 2009, the balance of this loan was $1.4 million.

Proceeds from the issuance of first mortgage bonds were used to repay borrowings under Westar Energy's revolving credit facility, with those 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 agreements. We calculate these ratios in accordance with our credit 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, 2009.

Maturities

Maturities of long-term debt as of December 31, 2009, are as follows.

Year	Principal Amount (In Thousands)
2010	$ 1,345
2011	61
2012	—
2013	—
Thereafter	2,495,663
Total long-term debt maturities	$2,497,069

Our interest expense on long-term debt was $139.6 million in 2009, $95.7 million in 2008 and $94.2 million in 2007.

10. TAXES

Income tax expense is composed of the following components.

	Year Ended December 31,		
	2009	2008	2007
		(In Thousands)	
Income Tax Expense (Benefit) from Continuing Operations:			
Current income taxes:			
Federal	$ 2,428	$ (16,484)	$ 40,648
State	9,975	(14,841)	9,107
Deferred income taxes:			
Federal	46,148	35,818	9,962
State	3,003	2,147	6,240
Investment tax credit amortization	(2,704)	(2,704)	(2,118)
Income tax expense from continuing operations	$ 58,850	$ 3,936	$ 63,839
Income Tax Expense (Benefit) from Discontinued Operations:			
Current income taxes:			
Federal	$ (25,528)	$ —	$ —
State	(10,418)	—	—
Deferred income taxes:			
Federal	(20,549)	—	—
State	—	—	—
Income tax expense from discontinued operations	$ (56,495)	$ —	$ —
Total income tax expense	$ 2,355	$ 3,936	$ 63,839

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

	December 31,	
	2009	2008
	(In Thousands)	
Current deferred tax assets	$ 7,927	$ 16,416
Non-current deferred tax liabilities	964,461	1,004,920
Net deferred tax liabilities	$ 956,534	$ 988,504

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.

	December 31,	
	2009	2008
	(In Thousands)	
Deferred tax assets:		
Deferred employee benefit costs	$ 132,770	$ 162,130
Business tax credit carryforwards (a)	101,347	6,528
Deferred gain on sale-leaseback	47,800	50,218
Deferred compensation	38,198	37,221
Accrued liabilities	35,230	33,038
Alternative minimum tax carryforward (b)	18,406	7,811
Disallowed costs	14,000	14,648
Capital loss carryforward (c)	6,075	215,946
Long-term energy contracts	5,874	7,088
Other	41,254	37,916
Total gross deferred tax assets	440,954	572,544
Less: Valuation allowance (c)	9,710	219,537
Deferred tax assets	$ 431,244	$ 353,007
Deferred tax liabilities:		
Accelerated depreciation	$ 789,850	$ 709,097
Acquisition premium	203,959	211,972
Amounts due from customers for future income taxes, net	165,975	179,283
Deferred employee benefit costs	141,974	173,457
Other	86,020	67,702
Total deferred tax liabilities	$1,387,778	$1,341,511
Net deferred tax liabilities	$ 956,534	$ 988,504

(a) As of December 31, 2009, we had available federal general business tax credits of $18.4 million and state investment tax credits of $82.9 million. The federal general business tax credits were generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These tax credits expire beginning in 2019 and ending in 2025. The state investment tax credits expire beginning in 2011. We believe these tax credits will be fully utilized prior to expiration.

(b) As of December 31, 2009, we had available alternative minimum tax credit carryforwards of $18.4 million. These tax credits have an unlimited carryforward period.

(c) As of December 31, 2009, we had a net capital loss of $15.3 million that was available to offset future capital gains. Of this amount, $0.5 million will expire in 2013 and $14.8 million will expire in 2014. As we do not expect to realize any significant capital gains in the future, a valuation allowance of $5.9 million has been established. In addition, a valuation allowance of $3.8 million has been established for certain deferred tax assets related to the write-down of other investments. The total valuation allowance related to the deferred tax assets was $9.7 million as of December 31, 2009, and $219.5 million as of December 31, 2008. The net reduction in the valuation allowance of $209.8 million was due to the expiration of the capital loss arising from the sale of Protection One, Inc. (Protection One). See the discussion below regarding the settlement with the Internal Revenue Service (IRS) Office of Appeals for years 2003 and 2004.

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

The 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,		
	2009	2008	2007
Statutory federal income tax rate from continuing operations	35.0%	35.0%	35.0%
Effect of:			
Corporate-owned life insurance policies	(8.2)	(9.1)	(5.8)
State income taxes	4.3	(4.5)	4.4
Accelerated depreciation flow through and amortization	3.7	2.3	2.7
Production tax credits	(3.0)	—	—
Amortization of federal investment tax credits	(1.4)	(1.5)	(0.9)
AFUDC equity	(0.9)	(3.5)	(0.6)
Capital loss utilization	(0.4)	—	(1.2)
Liability for unrecognized income tax benefits	0.2	(15.4)	0.6
Net operating loss utilization	—	—	(5.1)
Other	0.1	(1.1)	(1.6)
Effective income tax rate from continuing operations	29.4%	2.2%	27.5%

We file income tax returns in the U.S. federal jurisdiction, and various state and foreign jurisdictions. The income tax returns we file will likely be audited by the IRS or other taxing 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 are closed for tax years before 2003.

In February 2008, we reached a settlement with the IRS for tax years 1995 through 2002 on issues related principally to the method used to capitalize overheads to electric plant. This settlement resulted in a 2008 net earnings benefit of approximately $39.4 million, including interest, due to the recognition of previously unrecognized income tax benefits.

In January 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, 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 tax years after 2004. On March 31, 2009, we filed amended federal income tax returns for tax years 2005, 2006 and 2007 to claim a portion of the tax benefits from the net operating loss carryforward. The IRS examined these amended federal income tax returns in 2009 during its examination of tax year 2007 and we have agreed on a tentative settlement. The settlement is subject to formal review and approval by the IRS and the Joint Committee on Taxation of the U.S. Congress. If the settlement is effected in accordance with our expectations, we will receive a tax refund of $34.9 million, which will have no impact on our consolidated statements of income. We expect to realize the remainder of the tax benefits from the net operating loss carryforward in future tax years. We have extended the statute of limitation for tax years 2004, 2005 and 2006 until December 31, 2010.

In January 2010, we were notified that the IRS will commence an examination of our federal income tax return for tax year 2008 in the first quarter of 2010.

Under the terms of our tax sharing agreement, we reimburse subsidiaries for current tax benefits used in our consolidated tax return. Under an agreement relating to the sale of Protection One in 2004, we are required to pay Protection One an amount equal to 50% of the net tax benefit (less certain adjustments) that we will receive from the net operating loss carryforward arising from the sale. In December 2009, we finalized this tax matter as well as all other outstanding claims and paid Protection One $22.8 million. With this payment, we have no further obligations to Protection One. We recorded a net earnings benefit in discontinued operations of approximately $33.7 million to reflect the tax benefit of the IRS settlement (discussed further in the paragraphs above) net of the payment to Protection One.

The amount of unrecognized income tax benefits decreased from $92.1 million at December 31, 2008, to $8.4 million at December 31, 2009. The net decrease in unrecognized income tax benefits for which a liability was not recorded was largely attributable to the recognition of a $56.5 million income tax benefit from a refund claim pertaining to the net operating loss carryforward generated by the sale of Protection One, the recognition of a $23.3 million tax benefit from the general business credit carryforwards utilized on settlement of uncertain income tax positions and the reversal of $7.2 million of tax reserves due to the expiration of the statute of limitation. We expect a reduction of unrecognized income tax benefits in the amount of $4.9 million in 2010 if the IRS and the Joint Committee on Taxation of the U.S. Congress approve the settlement of tax years 1999, 2005, 2006 and 2007. We do not expect any other significant change in the liability for unrecognized income tax benefits in the next 12 months. A reconciliation of the beginning and ending amount of unrecognized income tax benefits is as follows:

	2009	2008	2007
		(In Thousands)	
Liability for unrecognized income tax benefits at January 1	$ 38,980	$ 70,833	$ 50,211
Additions based on tax positions related to the current year	2,254	4,576	21,660
Additions for tax positions of prior years	—	—	5,197
Reductions for tax positions of prior years	(25,722)	(3,639)	—
Settlements	(7,155)	(32,790)	(6,235)
Liability for unrecognized income tax benefits at December 31	8,357	38,980	70,833
Unrecognized income tax benefits related to amended returns filed in 2007	—	53,092	138,778
Unrecognized income tax benefits at December 31	$ 8,357	$ 92,072	$ 209,611

The amounts of unrecognized income tax benefits that, if recognized, would favorably impact our tax provisions from continuing or discontinued operations, were $2.1 million, $54.8 million and $172.2 million (net of tax) as of December 31, 2009, 2008 and 2007, respectively. Included in the liability for unrecognized income tax benefits balances was $2.1 million, $1.7 million and $33.4 million (net of tax) of tax positions, which if recognized, would favorably impact our effective income tax rates from continuing operations as of December 31, 2009, 2008 and 2007, respectively.

Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. During 2009, 2008 and 2007, we reversed interest expense previously recorded for income tax uncertainties of $2.4 million, $15.9 million and $5.3 million, respectively. As of December 31, 2009 and 2008, we had $1.4 million and $3.8 million, respectively, accrued for interest on our liability related to unrecognized tax benefits. There were no penalties accrued at either December 31, 2009, or December 31, 2008.

As of December 31, 2009 and 2008, we maintained reserves of $3.6 million and $3.5 million, respectively, for probable assessments of taxes other than income taxes.

11. EMPLOYEE BENEFIT PLANS

Pension and Other 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, are covered by the same defined benefit 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 officers. With the exception of one current officer, we have discontinued accruing any future benefits under this non-qualified plan.

As provided in the September 11, 2009, KCC order regarding pension and post-retirement benefits, we expect to fund our pension plan each year at least to a level equal to our current year pension expense. In addition, our pension plan contributions must also meet the minimum funding requirements under the Employee Retirement Income Security Act (ERISA) as amended by the Pension Protection Act. We may contribute additional amounts from time to time.

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 cost of post-retirement benefits during an employee's years of service. We fund the portion of net periodic costs for other 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 other post-retirement benefit plans. See Note 12, "Wolf Creek Employee Benefit Plans" for information about Wolf Creek's benefit plans.

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

As of December 31,	Pension Benefits 2009	Pension Benefits 2008	Post-retirement Benefits 2009	Post-retirement Benefits 2008
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 629,238	$ 578,191	$ 133,881	$ 134,135
Service cost	12,882	10,102	1,529	1,446
Interest cost	38,162	35,792	6,917	7,637
Plan participants' contributions	—	—	3,098	4,162
Benefits paid	(28,526)	(28,459)	(9,960)	(9,639)
Actuarial losses (gains)	10,692	32,151	(13,063)	(6,541)
Amendments	47	1,461	6,596	2,681
Benefit obligation, end of year	$ 662,495	$ 629,238	$ 128,998	$ 133,881
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 310,531	$ 468,188	$ 52,804	$ 61,423
Actual return on plan assets	83,128	(145,962)	17,898	(14,762)
Employer contributions	37,304	15,000	9,951	11,348
Plan participants' contributions	—	—	2,953	3,996
Part D Reimbursements	—	—	589	1,465
Benefits paid	(26,720)	(26,695)	(10,081)	(10,666)
Fair value of plan assets, end of year	$ 404,243	$ 310,531	$ 74,114	$ 52,804
Funded status, end of year	$ (258,252)	$ (318,707)	$ (54,884)	$ (81,077)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (1,984)	$ (1,933)	$ (121)	$ (125)
Noncurrent liability	(256,268)	(316,774)	(54,763)	(80,952)
Net amount recognized	$ (258,252)	$ (318,707)	$ (54,884)	$ (81,077)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 275,417	$ 324,290	$ 5,481	$ 31,648
Prior service cost	7,872	10,492	19,219	14,127
Transition obligation	—	—	12,060	16,048
Net amount recognized	$ 283,289	$ 334,782	$ 36,760	$ 61,823

As of December 31,	Pension Benefits 2009	Pension Benefits 2008	Post-retirement Benefits 2009	Post-retirement Benefits 2008
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 662,495	$ 629,238	$ —	$ —
Accumulated benefit obligation	559,021	531,145	—	—
Fair value of plan assets	404,243	310,531	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 662,495	$ 629,238	$ —	$ —
Accumulated benefit obligation	559,021	531,145	—	—
Fair value of plan assets	404,243	310,531	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 128,998	$ 133,881
Fair value of plan assets	—	—	74,114	52,804
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.95%	6.10%	5.65%	6.05%
Compensation rate increase	4.00%	4.00%	—	—

We use a measurement date of December 31 for our pension and other post-retirement benefit plans. In addition, we use 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 our pension plan and develop a single-point discount rate matching the plan's payout structure.

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 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.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2009	2008	2007	2009	2008	2007
			(Dollars in Thousands)			
Components of Net Periodic Cost (Benefit):						
Service cost	$ 12,882	$ 10,102	$ 9,641	$ 1,529	$ 1,446	$ 1,548
Interest cost	38,162	35,792	32,418	6,917	7,637	7,574
Expected return on plan assets	(37,826)	(40,332)	(38,506)	(4,756)	(4,694)	(3,827)
Amortization of unrecognized:						
Transition obligation, net	—	—	—	3,912	3,930	3,930
Prior service costs	2,668	2,550	2,545	1,580	1,412	937
Actuarial loss/(gain), net	14,263	8,415	7,864	(38)	904	1,503
Net periodic cost	$ 30,149	$ 16,527	$ 13,962	$ 9,144	$ 10,635	$ 11,665
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$ (34,610)	$ 218,444	$ 20,017	$ (26,205)	$ 12,915	$ (5,431)
Amortization of actuarial (loss)/gain	(14,263)	(8,415)	(7,864)	38	(904)	(1,503)
Current year prior service cost	48	1,461	136	6,672	2,681	13,778
Amortization of prior service costs	(2,668)	(2,550)	(2,545)	(1,580)	(1,412)	(937)
Current year offset of Initial Transition Asset due to plan change	—	—	—	(76)	—	—
Amortization of transition obligation	—	—	—	(3,912)	(3,930)	(3,930)
Total recognized in regulatory assets	$ (51,493)	$ 208,940	$ 9,744	$ (25,063)	$ 9,350	$ 1,977
Total recognized in net periodic cost and regulatory assets	$ (21,344)	$ 225,467	$ 23,706	$ (15,919)	$ 19,985	$ 13,642
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):						
Discount rate	6.10%	6.25%	5.90%	6.05%	6.10%	5.80%
Expected long-term return on plan assets	8.25%	8.50%	8.50%	7.75%	7.75%	7.75%
Compensation rate increase	4.00%	4.00%	4.00%	—	—	—

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2010 are as follows:

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 16,980	$ 404
Prior service cost	2,668	2,176
Transition obligation	—	3,912
Total	$ 19,648	$ 6,492

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 portfolio. 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 portfolio, 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 (Medicare Act) 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. We believe our retiree health care benefit plan is at least actuarially equivalent to Medicare and is, 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 2009. For 2008 and 2007, treating the future subsidy under the Medicare Act as an actuarial experience gain, as required by the guidance, decreased the accumulated post-retirement benefit obligation by approximately $4.0 million and $4.6 million, respectively. The subsidy also decreased the net periodic post-retirement benefit cost by approximately $1.9 million for 2009, $0.5 million for 2008 and $0.6 million for 2007.

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

	As of December 31,	
	2009	2008
Health care cost trend rate assumed for next year	8.0%	7.5%
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	2014

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	$ (44)	$ 28
Effect on post-retirement benefit obligation	1,008	(771)

Plan Assets

We manage pension and other post-retirement benefit plan assets in accordance with the prudent investor guidelines contained in the ERISA. The plans' investment strategies support the objectives of the funds, which are to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. We diversify investments across classes, sectors and manager style to minimize the risk of large losses. We delegate investment management to specialists in each asset class and, where appropriate, provide the investment manager with specific guidelines, which include allowable and/or prohibited investment types. 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. We have also established restrictions for certain classes of plan assets including that international equity securities should not exceed 25% of total pension plan assets, private equity investments should not exceed 10% of total pension plan assets and high yield fixed income investments should not exceed 15% of total pension plan assets. Additionally, 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. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

The target allocations for our pension plan assets are 60% to equity securities, 30% to debt securities, 5% to real estate securities and 5% to commodity investments. Our investments in equity securities include investments in domestic and foreign large-, mid- and small-cap companies, private equity funds and investment funds with underlying investments similar to those previously mentioned. Our investments in debt securities include core and high yield bonds. Core bonds are comprised of investment grade debt securities of corporate entities, obligations of U.S. and foreign governments and their agencies, private debt securities and investment funds with underlying investments similar to those previously mentioned. High yield bonds include non-investment grade debt securities of corporate entities and an investment fund with underlying investments in high yield bonds, private placements, bank debt, warrants and convertible bonds. Real estate securities include funds invested in commercial and residential real estate properties while commodity investments include funds invested in commodity-related instruments.

The target allocations for our other post-retirement benefit plan assets are 65% to equity securities and 35% to debt securities. Our investments in equity securities include investments 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 corporate entities, obligations of the U.S. government and its agencies, and cash and cash equivalents.

Most of our 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 our investments is comprised of private equity investments, debt securities or 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 initially measured at cost or at the value derived from subsequent financing with adjustments when actual performance differs significantly from expected performance; when market, economic or company-specific conditions change; or when other news or events have a material impact on the security. Debt investments for which we apply unobservable information are measured at fair value using subjective estimates such as projected cash flows and future interest rates. Real estate securities are measured at fair value using 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 other post-retirement benefit plan assets at fair value. 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 our pension plan assets and their corresponding level of hierarchy as of December 31, 2009.

As of December 31, 2009	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ 117,862	$ 20,663	$ 9,310	$ 147,835
International equity	49,122	51,583	—	100,705
Core bonds	—	72,038	—	72,038
High-yield bonds	—	19,055	22,519	41,574
Real estate securities	—	—	14,518	14,518
Commodities	—	20,719	—	20,719
Cash equivalents	—	6,854	—	6,854
Total Assets Measured at Fair Value	$ 166,984	$ 190,912	$ 46,347	$ 404,243

The following table provides a reconciliation of pension plan assets measured at fair value using significant level 3 inputs for the year ended December 31, 2009.

	Domestic Equity	High-yield Bonds	Real Estate Securities	Net Balance
		(In Thousands)		
Balance as of January 1, 2009	$ 8,422	$ 16,993	$ 19,985	$ 45,400
Actual gain (loss) on plan assets:				
Relating to assets still held at the reporting date	(132)	4,991	(5,643)	(784)
Relating to assets sold during the period	—	535	176	711
Purchases, issuances and settlements	1,020	—	—	1,020
Balance as of December 31, 2009	$ 9,310	$ 22,519	$ 14,518	$ 46,347

The following table provides the fair value of our other post-retirement benefit plan assets and their corresponding level of hierarchy as of December 31, 2009.

As of December 31, 2009	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ —	$ 38,648	$ —	$ 38,648
International equity	—	9,674	—	9,674
Core bonds	—	25,792	—	25,792
Total Assets Measured at Fair Value	$ —	$ 74,114	$ —	$ 74,114

Cash Flows

The following table shows the expected cash flows for our pension and other 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:				
2010	$ 22.4	$ 2.0	$ 11.2	$ 0.1
Expected benefit payments:				
2010	$ (27.3)	$ (2.0)	$ (8.3)	$ (0.1)
2011	(27.9)	(1.9)	(8.6)	(0.1)
2012	(29.1)	(1.9)	(8.8)	(0.1)
2013	(30.8)	(1.9)	(9.1)	(0.1)
2014	(32.9)	(1.9)	(9.6)	(0.1)
2015 – 2019	(203.3)	(8.9)	(52.7)	(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 $6.5 million in 2009, $6.1 million in 2008 and $5.6 million in 2007.

Stock-Based Compensation Plans

We have a long-term incentive and share award plan (LTISA Plan), which is a stock-based compensation plan in which employees and directors are eligible for awards. The LTISA Plan was implemented as a means to attract, retain and motivate employees and directors. Under the LTISA Plan, we may grant awards in the form of stock options, dividend equivalents, share appreciation rights, RSUs, performance shares and performance share units to plan participants. Up to five million shares of common stock may be granted under the LTISA Plan. As of December 31, 2009, awards of 3,901,718 shares of common stock had been made under the plan. Dividend equivalents, or the rights to receive cash equal to the value of dividends paid on Westar Energy's common stock, accrue on the awarded RSUs.

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 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,		
	2009	2008	2007
		(In Thousands)	
Compensation expense	$ 5,080	$ 4,619	$ 5,735
Income tax benefits related to stock-based compensation arrangements	2,011	1,830	2,281

Since 2002, we have used RSU awards exclusively 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. We measure the fair value of the RSU awards based on the market price of the underlying common stock as of the date of grant and recognize that cost as an expense in the consolidated statement of income over the requisite service period. The requisite service periods range from one to ten years. 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.

During the years ended December 31, 2009, 2008 and 2007, our RSU activity was as follows:

	As of December 31,					
	2009		2008		2007	
	Shares (In Thousands)	Weighted-Average Grant Date Fair Value	Shares (In Thousands)	Weighted-Average Grant Date Fair Value	Shares (In Thousands)	Weighted-Average Grant Date Fair Value
Nonvested balance, beginning of year	727.4	$ 20.86	984.2	$ 23.11	933.4	$ 20.82
Granted	83.5	18.33	38.7	25.46	413.8	26.76
Vested	(439.0)	19.43	(261.3)	28.11	(308.5)	20.53
Forfeited	(3.1)	20.63	(34.2)	35.49	(54.5)	26.79
Nonvested balance, end of year	368.8	21.98	727.4	20.86	984.2	23.11

Total unrecognized compensation cost related to RSU awards was $2.6 million as of December 31, 2009. We expect to recognize these costs over a remaining weighted-average period of 2.3 years. The total fair value of shares vested during the years ended December 31, 2009, 2008 and 2007, was $8.8 million, $6.2 million and $8.3 million, respectively. There were no modifications of awards during the years ended December 31, 2009, 2008 or 2007.

RSU awards that can be settled in cash upon a change in control are classified as temporary equity. As of December 31, 2009 and 2008, we had temporary equity of $3.4 million on our consolidated balance sheets. If we determine that it is probable that these awards will be settled in cash, the awards will be reclassified as a liability.

Stock options granted between 1998 and 2001 are completely vested and expire 10 years from the date of grant. All 2,400 outstanding options are exercisable. There were no options exercised and 21,300 options were forfeited during the year ended December 31, 2009. We currently have no plans to issue new stock option awards.

Another component of the LTISA Plan is the Executive Stock for Compensation program, where, in the past, eligible employees were entitled to receive deferred 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 7,106 shares of common stock for dividends in 2009, 5,283 shares in 2008 and 4,214 shares in 2007. Participants received common stock distributions of 563 shares in 2009, 530 shares in 2008 and 505 shares in 2007.

Cash retained as a result of excess tax benefits resulting from the 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 Other 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 other post-retirement benefit plans. KGE accrues its 47% share of the Wolf Creek cost of pension and other post-retirement benefits during the years an employee provides service. The following tables summarize the net periodic costs for KGE's 47% share of the Wolf Creek pension and other post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2009	2008	2009	2008
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 99,536	$ 89,846	$ 8,852	$ 8,596
Effect of eliminating early measurement date	—	574		—
Service cost	3,643	3,421	188	203
Interest cost	6,401	5,680	538	517
Plan participants' contributions	—	—	439	356
Benefits paid	(2,273)	(2,135)	(1,151)	(1,182)
Actuarial losses	3,726	2,150	708	362
Benefit obligation, end of year	$ 111,033	$ 99,536	$ 9,574	$ 8,852
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 45,201	$ 54,992	$ —	$ —
Effect of eliminating early measurement date	—	226	—	—
Actual return on plan assets	12,109	(14,656)	—	—
Employer contribution	7,310	6,608	—	—
Benefits paid	(2,104)	(1,969)	—	—
Fair value of plan assets, end of year	$ 62,516	$ 45,201	$ —	$ —
Funded status, end of year	$ (48,517)	$ (54,335)	$ (9,574)	$ (8,852)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (253)	$ (251)	$ (674)	$ (612)
Noncurrent liability	(48,264)	(54,084)	(8,900)	(8,240)
Net amount recognized	$ (48,517)	$ (54,335)	$ (9,574)	$ (8,852)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 34,857	$ 40,802	$ 3,709	$ 3,258
Prior service cost	76	119	—	—
Transition obligation	109	166	173	230
Net amount recognized	$ 35,042	$ 41,087	$ 3,882	$ 3,488

As of December 31,	Pension Benefits 2009	Pension Benefits 2008	Post-retirement Benefits 2009	Post-retirement Benefits 2008
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 111,033	$ 99,536	$ —	$ —
Accumulated benefit obligation	90,157	77,197	—	—
Fair value of plan assets	62,516	45,201	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 111,033	$ 99,536	$ —	$ —
Accumulated benefit obligation	90,157	77,197	—	—
Fair value of plan assets	62,516	45,201	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 9,574	$ 8,852
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.05%	6.15%	5.50%	6.05%
Compensation rate increase	4.00%	4.00%	—	—

During 2008, Wolf Creek changed the measurement date for its pension and other post-retirement benefit plans from December 1 to December 31. As a result, we decreased retained earnings by $0.5 million and regulatory assets by $0.1 million in 2008.

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 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 loss subject to amortization 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.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2009	2008	2007	2009	2008	2007
			(Dollars in Thousands)			
Components of Net Periodic Cost:						
Service cost	$ 3,643	$ 3,421	$ 3,436	$ 188	$ 203	$ 234
Interest cost	6,401	5,680	4,696	538	517	435
Expected return on plan assets	(4,976)	(4,709)	(4,101)	—	—	—
Amortization of unrecognized:						
Transition obligation, net	57	57	57	58	58	58
Prior service costs	43	57	57	—	—	—
Actuarial loss, net	2,538	1,696	1,855	257	231	191
Curtailments, settlements and special termination benefits	—	—	1,486	—	—	259
Net periodic cost	$ 7,706	$ 6,202	$ 7,486	$ 1,041	$ 1,009	$ 1,177
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$ (3,407)	$ 21,517	$ 3,578	$ 708	$ 362	$ 786
Amortization of actuarial loss	(2,538)	(1,696)	(1,855)	(257)	(231)	(191)
Current year prior service cost	—	—	34	—	—	—
Amortization of prior service cost	(43)	(57)	(57)	—	—	—
Amortization of transition obligation	(57)	(57)	(57)	(58)	(58)	(58)
Total recognized in regulatory assets	$ (6,045)	$ 19,707	$ 1,643	$ 393	$ 73	$ 537
Total recognized in net periodic cost and regulatory assets	$ 1,661	$ 25,909	$ 9,129	$ 1,434	$ 1,082	$ 1,714
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:						
Discount rate	6.15%	6.15%	5.70%	6.05%	6.05%	5.80%
Expected long-term return on plan assets	8.00%	8.25%	8.25%	—	—	—
Compensation rate increase	4.00%	4.00%	3.25%	—	—	—

In January 2007, Wolf Creek Nuclear Operating Corporation (WCNOC) offered a selective retirement incentive to employees. The incentive increased the pension benefit for eligible employees who elected retirement. This resulted in $1.5 million in additional pension benefits and $0.3 million in additional post-retirement benefits for the year ended December 31, 2007.

The estimated amounts that will be amortized from regulatory assets into net periodic cost in 2010 are as follows:

	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 2,425	$ 277
Prior service cost	29	—
Transition obligation	57	58
Total	$ 2,511	$ 335

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 portfolio. 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 portfolio 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,	
	2009	2008
Health care cost trend rate assumed for next year	8.0%	7.5%
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	2014

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	$ (7)	$ 6
Effect on the present value of the projected benefit obligation	(64)	58

Plan Assets

Wolf Creek does not utilize a separate investment trust for the purpose of funding other post-retirement benefits as it does for its pension plan. The Wolf Creek pension plan investment strategy supports the objective of the fund, 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 manager 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. 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.

The target allocations for Wolf Creek's pension plan assets are 20% to international equity securities, 45% 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 securities 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 securities 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.

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 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 other post-retirement benefit plan assets at fair value. 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 their corresponding level of hierarchy as of December 31, 2009.

As of December 31, 2009	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ 24,947	$ 3,451	$ —	$ 28,398
International equity	8,021	4,458	—	12,479
Core bonds	—	11,864	—	11,864
High-yield bonds	3,018	—	—	3,018
Real estate securities	—	—	2,416	2,416
Commodities	—	3,594	—	3,594
Cash equivalents	1	746	—	747
Total Assets Measured at Fair Value	$ 35,987	$ 24,113	$ 2,416	$ 62,516

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 year ended December 31, 2009.

	Real Estate Securities (In Thousands)
Balance as of January 1, 2009	$ —
Actual gain (loss) on plan assets:	
Relating to assets still held at the reporting date	(370)
Relating to assets sold during the period	6
Purchases, issuances and settlements	2,780
Balance as of December 31, 2009	$ 2,416

Cash Flows

The following table shows the expected cash flows for KGE's 47% share of Wolf Creek's pension and other 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:				
2010	$ 4.1	$ 0.2	$ —	$ 0.7
Expected benefit payments:				
2010	$ (2.4)	$ (0.2)	$ —	$ (0.7)
2011	(2.7)	(0.2)	—	(0.7)
2012	(3.0)	(0.2)	—	(0.7)
2013	(3.4)	(0.2)	—	(0.7)
2014	(3.9)	(0.2)	—	(0.7)
2015 – 2019	(28.4)	(1.1)	—	(3.8)

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 $1.1 million in 2009, $1.0 million in 2008 and $0.9 million in 2007.

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 $516.1 million as of December 31, 2009, of which $186.7 million has been committed. The $186.7 million commitment relates to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments as of December 31, 2009, was as follows.

	Committed Amount
	(In Thousands)
2010	$ 113,946
2011	34,021
2012	24,063
Thereafter	14,660
Total amount committed	$ 186,690

Clean Air Act

We must comply with the Clean Air Act, state laws and implementing regulations that impose, among other things, limitations on pollutants generated during our operations, including sulfur dioxide (SO_2), particulate matter and nitrogen oxides (NOx). In addition, we must comply with the provisions of the Clean Air Act Amendments of 1990 that require a reduction in SO_2 and NOx. We have installed continuous monitoring and reporting equipment in order to meet these requirements.

Environmental Projects

We will continue to make significant capital expenditures at our power plants to reduce undesirable emissions. The amount of these expenditures could materially increase or decrease 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.

The environmental cost recovery rider allows for the more timely inclusion in retail prices the costs of capital expenditures associated with environmental improvements, including those required by the Federal Clean Air Act. In order to change our prices to recognize increased operating and maintenance costs, however, we must still file a general rate case with the KCC.

We have an agreement with the Kansas Department of Health and Environment (KDHE) to implement a plan to install new equipment to reduce regulated emissions from our generating fleet. The projects are designed to meet requirements of the Clean Air Visibility Rule and significantly reduce plant emissions.

While an earlier issued Environmental Protection Agency (EPA) rule on mercury was vacated by a U.S. Court of Appeals ruling, the Obama administration has indicated that it intends to enact stricter, technology-based regulations on mercury emissions. Our costs to comply with mercury emission requirements could be material.

EPA Lawsuit

Under Section 114(a) of the Federal Clean Air Act, the EPA is conducting investigations nationwide to determine whether modifications at coal-fired power plants are subject to the New Source Review permitting program or New Source Performance Standards. These investigations focus on whether projects at coal-fired plants were routine maintenance or whether the projects were substantial modifications that could reasonably have been expected to result in a significant net increase in emissions. The New Source Review program requires companies to obtain permits and, if necessary, install control equipment to address emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in emissions.

On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated certain requirements of the New Source Review program. On February 4, 2009, the Department of Justice (DOJ), on behalf of the EPA, filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. On January 25, 2010, we announced a settlement of the lawsuit. The settlement was filed with the court, seeking its approval. The settlement provides for us to install a selective catalytic reduction (SCR) system on one of the three Jeffrey Energy Center coal units by the end of 2014. We have not yet engineered this project; however, our preliminary estimate of the cost of this SCR is approximately $200.0 million. Depending on the NOx emission reductions attained by the single SCR and attainable through the installation of other controls on the other two Jeffrey Energy Center coal units, a second SCR system would be installed on another Jeffrey Energy Center coal unit by the end of 2016, if needed to meet NOx reduction targets. Recovery of costs to install these systems is subject to the approval of our regulators. We believe these costs are appropriate for inclusion in the prices we are allowed to charge our customers. We will also invest $5.0 million over six years in environmental mitigation projects which we will own and $1.0 million in environmental mitigation projects that will be owned by a qualifying third party. We will also pay a $3.0 million civil penalty. Accordingly, we have recorded a $4.0 million liability pursuant to the terms of the settlement. We expect the court to make a decision in 2010 following the expiration of a period for public comments on March 1, 2010. If the court does not approve the settlement, and the lawsuit proceeds to trial, a decision in favor of the DOJ and EPA could require us to update or install additional emissions controls at Jeffrey Energy Center, and the additional controls could be more extensive than those required by the current settlement. Additionally, we could be required to update or install emissions controls at our other coal-fired plants, pay fines or penalties or take other remedial action. Our ultimate costs to resolve the lawsuit could be material and we would expect to incur substantial legal fees and expenses related to the defense of the lawsuit. We are not able to estimate the possible loss or range of loss if the court were to not approve the settlement.

FERC Investigation

We continue to respond to a non-public investigation by FERC of our use of transmission service between July 2006 and February 2008. On May 7, 2009, FERC staff advised us that it had preliminarily concluded 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 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 revised 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. We continue to believe that our use of transmission service was in compliance with FERC orders and SPP tariffs. We are now reviewing FERC staff's revised preliminary conclusions and plan to submit a response in the near future. 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 refunds and fines, the amounts of which could be material, and potentially could alter the manner in which we are permitted to buy and sell energy and use transmission service.

Manufactured Gas Sites

We have been identified as being partially responsible for remediating a number of former manufactured gas sites located in Kansas and Missouri. We and the KDHE entered into a consent agreement governing all future work at the Kansas sites. Under the terms of the consent agreement, we agreed to investigate and, if necessary, remediate these sites. Pursuant to an environmental indemnity agreement with ONEOK, Inc. (ONEOK), the current owner of some of the sites, 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. We have sole responsibility for remediation with respect to three sites.

Our liability for the former manufactured gas sites identified in Missouri is limited to $7.5 million by the terms of an environmental indemnity agreement with the purchaser of our former Missouri assets.

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 by the KCC of a "funding schedule" prepared by the owner of the nuclear facility detailing how it plans to fund the future-year dollar amount of its pro rata share of the plant.

In August 2009, the KCC approved Wolf Creek's updated nuclear decommissioning site study. Based on the study, our share of decommissioning costs, including decontamination, dismantling and site restoration, is estimated to be $279.0 million. This amount compares to the prior site study estimate of $243.3 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.

In the prices we charge, we are allowed to recover nuclear decommissioning costs over the life of Wolf Creek, which is through 2045. The NRC requires that funds sufficient to meet nuclear decommissioning obligations be held in 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 adversely affected if we were not allowed to recover in our prices the full amount of the funding requirement.

We recovered in our prices and deposited in an external trust fund for nuclear decommissioning approximately $2.9 million in each of 2009, 2008 and 2007. We record our investment in the nuclear decommissioning trust fund at fair value. The fair value approximated $112.3 million as of December 31, 2009, and $85.6 million as of December 31, 2008.

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 $3.7 million in 2009, $3.5 million in 2008 and $4.4 million in 2007. We include these costs in fuel and purchased power expense.

The NRC continues its technical licensing review of a DOE application for authority to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada. In February 2010, the DOE announced its intent to withdraw the application, which would end the licensing process. 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.

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 and property insurance programs 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, including replacement power costs. 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 twelve 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, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

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 $12.5 billion. This limit of liability consists of the maximum available commercial insurance of $300.0 million, and the remaining $12.2 billion is provided through mandatory participation in an industry-wide retrospective assessment program. The maximum available commercial insurance will increase to $375.0 million in 2010. Under this retrospective assessment program, the owners of Wolf Creek can be assessed a total of $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 August 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 nuclear decommissioning trust 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 $25.2 million (our share is $11.9 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 adverse effect on our consolidated financial results.

Purchased Power and Fuel Commitments

To supply a portion of the fuel requirements for our generating plants, WCNOC has entered into various commitments to obtain nuclear fuel and we have entered into various commitments to obtain coal and natural gas. Some of these contracts contain provisions for price escalation and minimum purchase commitments. As of December 31, 2009, our share of Wolf Creek's nuclear fuel commitments was approximately $54.2 million for uranium concentrates expiring in 2016, $8.2 million for conversion expiring in 2016, $135.3 million for enrichment expiring in 2024 and $47.6 million for fabrication expiring in 2024.

As of December 31, 2009, our coal and coal transportation contract commitments in 2009 dollars under the remaining terms of the contracts were approximately $1.3 billion. The two largest contracts expire in 2013 and 2020, with the remaining contracts expiring at various times prior to the end of 2013.

As of December 31, 2009, our natural gas transportation commitments in 2009 dollars under the remaining terms of the contracts were approximately $184.2 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2030.

During 2007, we entered into purchase power agreements with the owners of two separate wind generation facilities located in Kansas with a combined capacity of 146 MW. The agreements have a term of 20 years and provide for our receipt and purchase of the energy produced at a fixed price per unit of output. We estimate that our annual cost for energy purchased from these wind generation facilities will be approximately $22.0 million. One of the facilities was placed in service in December 2008 and the other one was placed in service in early 2009.

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 (our 47% share), 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,	
	2009	2008
	(In Thousands)	
Beginning ARO	$ 95,083	$ 88,711
Liabilities incurred	1,289	1,143
Liabilities settled	(1,922)	(195)
Accretion expense	4,727	5,424
Increase in nuclear decommissioning ARO liability	20,342	—
Ending ARO	$ 119,519	$ 95,083

In 2009, Wolf Creek filed an updated nuclear decommissioning study with the KCC. As a result of the study, we recorded a $20.3 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 disposal of asbestos insulating material at our power plants, the remediation of ash disposal ponds and the disposal of PCB-contaminated oil.

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.

Non-Legal Liability – Cost of Removal

We recover in our prices the costs to dispose of utility plant assets that do not represent legal retirement obligations. As of December 31, 2009 and 2008, we had $68.1 million and $50.1 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in our prices compared to removal costs incurred.

15. LEGAL PROCEEDINGS

In late 2002, two of our executive officers resigned or were placed on administrative leave from their positions. 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. As of December 31, 2009, and December 31, 2008, we had accrued liabilities of $77.6 million and $74.9 million, respectively, for compensation not yet paid to them, and $6.8 million for each respective period for legal fees and expenses they have incurred. The arbitration has been stayed pending final resolution of criminal charges filed by the United States Attorney's Office against them in U.S. District Court in the District of Kansas. We intend to vigorously defend against the counterclaims they filed in the arbitration. We are unable to predict the ultimate impact of this matter on our consolidated financial results.

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 adverse effect on our consolidated financial results.

See also Note 13, "Commitments and Contingencies."

16. COMMON AND PREFERRED STOCK

Activity in Westar Energy's stock accounts for each of the three years ended December 31 is as follows:

	Cumulative preferred stock shares	Common stock shares
Balance at December 31, 2006..	214,363	87,394,886
Issuance of common stock..........	—	8,068,294
Balance at December 31, 2007	214,363	95,463,180
Issuance of common stock..........	—	12,847,955
Balance at December 31, 2008	214,363	108,311,135
Issuance of common stock..........	—	760,865
Balance at December 31, 2009	214,363	109,072,000

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. As of December 31, 2009, we had 109,072,000 shares issued and outstanding.

Westar Energy has a direct stock purchase plan (DSPP). Shares sold pursuant to the DSPP may be either original issue shares or shares purchased in the open market. During 2009, a total of 760,865 shares were issued by Westar Energy through the DSPP and other stock-based plans operated under the 1996 LTISA Plan. As of December 31, 2009, a total of 3,196,816 shares were available under the DSPP registration statement.

Common Stock Issuance

On May 29, 2008, Westar Energy entered into an underwriting agreement relating to the offer and sale of 6.0 million shares of its common stock. On June 4, 2008, Westar Energy issued all 6.0 million shares and received $140.6 million in total proceeds, net of underwriting discounts and fees related to the offering.

On November 15, 2007, Westar Energy entered into a forward sale agreement with a bank, as forward purchaser, relating to 8.2 million shares of its common stock. The forward sale agreement provided for the sale of Westar Energy's common stock within approximately twelve months at a stated settlement price. In connection with the forward sale agreement, the bank borrowed an equal number of shares of Westar Energy's common stock from stock lenders and sold the borrowed shares to another bank under an underwriting agreement among Westar Energy and the banks. The underwriters subsequently offered the borrowed shares to the public at a price per share of $25.25.

On December 28, 2007, Westar Energy delivered 3.1 million newly issued shares of its common stock to a bank and received proceeds of $75.0 million as partial settlement of the forward sale agreement. Additionally, on February 7, 2008, Westar Energy delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. On June 30, 2008, Westar Energy completed the forward sale agreement by delivering 3.0 million shares and receiving proceeds of $73.0 million.

On August 24, 2007, Westar Energy entered into a Sales Agency Financing Agreement with a bank. Under the terms of the agreement, Westar Energy may offer and sell shares of its common stock from time to time through the bank, as agent, up to an aggregate of $200.0 million for a period of no more than three years. Westar Energy will pay the bank a commission equal to 1% of the sales price of all shares sold under the agreement. During 2007 Westar Energy sold 0.8 million shares of common stock through the bank for $20.0 million and received $19.8 million in proceeds net of commission. During 2008 Westar Energy sold 1.1 million shares of common stock through the bank for $26.9 million and received $26.7 million in proceeds net of commission. Westar Energy did not sell any shares of common stock under this agreement during 2009. In January and February 2010, Westar Energy sold 1.2 million shares of common stock through the bank for $25.0 million.

On April 12, 2007, Westar Energy entered into a Sales Agency Financing Agreement with the same bank. As of July 12, 2007, Westar Energy had sold 3.7 million shares of its common stock for $100.0 million pursuant to the agreement. Westar Energy received $99.0 million in proceeds net of a commission.

Westar Energy used the proceeds from the issuance of common stock to repay borrowings under its revolving credit facility, with those borrowed amounts principally related to our 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 our redemption amount for all series of preferred stock not subject to mandatory redemption as of December 31, 2009.

Rate	Shares	Principal Outstanding	Call Price	Premium	Total Cost to Redeem
		(Dollars in Thousands)			
4.500%	121,613	$12,161	108.00%	$ 973	$13,134
4.250%	54,970	5,497	101.50%	82	5,579
5.000%	37,780	3,778	102.00%	76	3,854
		$21,436		$1,131	$22,567

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, 2009, 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. LEASES

Operating Leases

We lease office buildings, computer equipment, vehicles, rail cars, a generating facility 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. The rental expense associated with the La Cygne unit 2 operating lease includes an offset for the amortization of the deferred gain on the sale-leaseback. The rental expense and estimated commitments are as follows for the La Cygne unit 2 lease and other operating leases.

Year Ended December 31,	La Cygne Unit 2 Lease (a)	Total Operating Leases
	(In Thousands)	
Rental expense:		
2007	$ 18,069	$ 35,267
2008	18,069	38,870
2009	18,069	38,096
Future commitments:		
2010	$ 33,041	$ 49,181
2011	33,122	48,450
2012	33,209	50,453
2013	33,350	46,698
2014	33,454	43,195
Thereafter	222,671	249,592
Total future commitments	$ 388,847	$ 487,569

(a) The La Cygne unit 2 lease amounts are included in the total operating leases column.

The La Cygne unit 2 lease will expire in September 2029. Upon expiration, KGE has a fixed price option to purchase La Cygne unit 2 for a price that is estimated to be the fair market value of the facility in 2029. KGE can also elect to renew the lease at the expiration of the lease term in 2029. However, any renewal period, when added to the initial lease term, cannot exceed 80% of the estimated useful life of La Cygne unit 2.

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 14 years depending on the type of vehicle. Computer equipment has a lease term of two to four years.

In April 2007, we completed the purchase of Aquila, Inc.'s 8% leasehold interest in Jeffrey Energy Center for $25.8 million and assumed the related lease obligation. This lease expires on January 3, 2019, and has a purchase option at the end of the lease term. Based on current economic and other conditions, we expect to exercise the purchase option. Based upon these expectations, we originally recorded a capital lease of $118.5 million which was subsequently adjusted to $118.6 million in 2009.

Assets recorded under capital leases are listed below.

	December 31, 2009	December 31, 2008
	(In Thousands)	
Vehicles	$ 18,991	$ 24,443
Computer equipment and software	4,640	6,133
Jeffrey Energy Center 8% interest	118,623	118,538
Accumulated amortization	(21,736)	(22,526)
Total capital leases	$ 120,518	$ 126,588

Capital lease payments are currently 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,	Jeffrey Energy Center 8% Interest (a) (In Thousands)	Total Capital Leases (In Thousands)
2010	$ 12,862	$ 17,685
2011	12,904	14,776
2012	9,853	11,540
2013	5,875	7,256
2014	5,875	7,037
Thereafter	110,525	111,547
	$ 157,894	169,841
Amounts representing imputed interest		(51,606)
Present value of net minimum lease payments under capital leases		118,235
Less current portion		8,935
Total long-term obligation under capital leases		$ 109,300

(a) The Jeffrey Energy Center 8% leasehold interest amounts are included in the total capital leases column.

As a result of the adoption of amended accounting guidance for VIEs effective January 1, 2010, we expect to consolidate certain trusts that hold assets we lease. We continue to evaluate the impact that consolidating these VIEs will have on our consolidated financial results; the change may be material. See Note 2, "Summary of Significant Accounting Policies," for additional information regarding the amended guidance.

18. DISCONTINUED OPERATIONS — Sale of Protection One

In January 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, 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. On March 31, 2009, we filed amended federal income tax returns for years 2005, 2006 and 2007 to claim a portion of the tax benefits from the net operating loss carryforward. We expect to realize the remainder of the 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.

19. QUARTERLY RESULTS (UNAUDITED)

Our electric 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.

2009	First (a)	Second (b)	Third	Fourth (a) (c)
	(In Thousands, Except Per Share Amounts)			
Revenues (d)	$ 421,767	$467,812	$ 528,534	$ 440,118
Net income (d)	44,164	38,386	81,142	11,384
Results of discontinued operations, net of tax	32,978	—	—	767
Net income attributable to common stock (d)	43,922	38,144	80,900	11,142
Per Share Data (d):				
Basic:				
Earnings available	$ 0.40	$ 0.35	$ 0.73	$ 0.10
Diluted:				
Earnings available	$ 0.40	$ 0.35	$ 0.73	$ 0.10
Cash dividend declared per common share	$ 0.30	$ 0.30	$ 0.30	$ 0.30
Market price per common share:				
High	$ 21.10	$ 19.32	$ 21.56	$ 22.30
Low	$ 14.86	$ 16.60	$ 17.91	$ 18.91

(a) In the first and fourth quarters of 2009, we recognized net earnings benefits from discontinued operations of approximately $33.0 million and $0.8 million, respectively, due to the re-characterization of a portion of the loss we incurred on the sale of Protection One, a former subsidiary, from a capital loss to an ordinary loss.

(b) In the second quarter of 2009, net income and net income attributable to common stock increased compared to the same period last year due principally to price increases authorized by the KCC.

(c) In the fourth quarter of 2009, net income and net income attributable to common stock decreased compared to the same period last year due principally to approximately $14.6 million net earnings benefits from state tax credits related to investment and jobs creation within the state of Kansas recognized in 2008 which did not occur in 2009.

(d) 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.

2008	First (a)	Second (b)	Third	Fourth (c)
	(In Thousands, Except Per Share Amounts)			
Revenues (d)	$ 406,827	$ 451,219	$ 574,853	$ 406,097
Net income (d)	61,136	5,845	88,285	22,874
Net income attributable to common stock (d)	60,894	5,603	88,043	22,632
Per Share Data (d):				
Basic:				
Earnings available	$ 0.62 (e)	$ 0.06	$ 0.80 (e)	$ 0.21
Diluted:				
Earnings available	$ 0.62	$ 0.06	$ 0.80 (e)	$ 0.21
Cash dividend declared per common share	$ 0.29	$ 0.29	$ 0.29	$ 0.29
Market price per common share:				
High	$ 25.92	$ 24.65	$ 24.97	$ 24.80
Low	$ 21.75	$ 21.20	$ 20.82	$ 15.97

(a) In the first quarter of 2008, we recognized a net earnings benefit of approximately $39.4 million, including interest, due to the recognition of previously unrecognized tax benefits.

(b) In the second quarter of 2008, net income and net income attributable to common stock decreased compared to the same period of 2007 due primarily to lower energy marketing and extended planned outages at our base load plants.

(c) In the fourth quarter of 2008, we recognized a net earnings benefit of approximately $14.6 million from state tax credits related to investment and jobs creation within the state of Kansas.

(d) 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.

(e) EPS amounts were adjusted to reflect the use of the two-class method. See Note 2, "Summary of Significant Accounting Policies—Earnings per Share," for additional information regarding the two-class method.

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, 2009, 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 management's assessment of the effectiveness of internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information concerning directors required by Item 401 of Regulation S-K will be included under the caption "Election of Directors" in our definitive Proxy Statement for our 2010 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (the 2010 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 2010 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 2010 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 2010 Proxy Statement under the captions "Compensation Discussion and Analysis," "Compensation Committee Report," "Compensation of Executive Officers and Directors," 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 2010 Proxy Statement under the captions "Beneficial Ownership of Voting Securities" and "Shares Authorized For Issuance Under Equity Compensation Plans," 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 2010 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 2010 Proxy Statement under the captions "Independent Registered Accounting Firm Fees" and "Audit Committee Pre-Approval Policies and Procedures," and that information is incorporated by reference in this Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

FINANCIAL STATEMENTS INCLUDED HEREIN

Westar Energy, Inc.

Management's Report on Internal Control Over Financial Reporting
Reports of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2009 and 2008
Consolidated Statements of Income for the years ended December 31, 2009, 2008 and 2007
Consolidated Statements of Comprehensive Income for the years ended December 31, 2009, 2008 and 2007
Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007
Consolidated Statements of Shareholders' Equity for the years ended December 31, 2009, 2008 and 2007
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 by an asterisk are management contracts or compensatory plans or arrangements required to be identified by Item 15(a)(3) of Form 10-K. All exhibits marked "#" are filed with this Form 10-K.

	Description	
1(a)	-Underwriting Agreement between Westar Energy, Inc., and Citigroup Global Markets Inc. and Lehman Brothers Inc., as representatives of the several underwriters, dated January 12, 2005 (filed as Exhibit 1.1 to the Form 8-K filed on January 18, 2005)	I
1(b)	-Underwriting Agreement between Westar Energy, Inc. and Barclays Capital and Citigroup Global Markets, Inc., as representatives of the several underwriters, dated June 27, 2005 (filed as Exhibit 1.1 to the Form 8-K filed on July 1, 2005)	I
1(c)	-Sales Agency Financing Agreement, dated as of April 12, 2007, between Westar Energy, Inc. and BNY Capital Markets, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on April 12, 2007)	I
1(d)	-Sales Agency Financing Agreement, dated as of August 24, 2007, between Westar Energy, Inc. and BNY Capital Markets, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on August 27, 2007)	I
1(e)	-Underwriting Agreement, dated November 15, 2007, among UBS Securities LLC and J.P. Morgan Securities Inc., as representatives of the underwriters named therein, UBS Securities LLC, in its capacity as agent for UBS AG, London Branch, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on November 16, 2007)	I
1(f)	- Underwriting Agreement, dated May 29, 2008, among Citigroup Global Markets Inc., Banc of America Securities LLC and UBS Securities LLC, as representatives of the underwriters named therein, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on June 4, 2008)	I
1(g)	-Underwriting Agreement, dated November 18, 2008, among J.P. Morgan Securities Inc. and Deutsche Bank Securities Inc., as representatives of the underwriters named therein, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on November 24, 2008)	I
3(a)	-By-laws of Westar Energy, Inc., as amended April 28, 2004 (filed as Exhibit 3(a) to the Form 10-Q for the period ended June 30, 2004 filed on August 4, 2004)	I
3(b)	-Restated Articles of Incorporation of Westar Energy, Inc., as amended through May 25, 1988 (filed as Exhibit 4 to the Form S-8 Registration Statement, SEC File No. 33-23022 filed on July 15, 1988)	I
3(c)	-Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-K405 for the period ended December 31, 1998 filed on April 14, 1999)	I
3(d)	-Certificate of Designations for Preference Stock, 8.5% Series (filed as Exhibit 3(d) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
3(e)	-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(f)	-Certificate of Designations for Preference Stock, 7.58% Series (filed as Exhibit 3(e) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
3(g)	-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(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 June 30, 1994 filed on August 11, 1994)	I
3(i)	-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(j)	-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(k)	-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(l)	-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(m)	-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(n)	-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
4(a)	-Mortgage and Deed of Trust dated July 1, 1939 between Westar Energy, Inc. and Harris Trust and	I

	Savings Bank, Trustee (filed as Exhibit 4(a) to Registration Statement No. 33-21739)	
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)	-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(k)	-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(l)	-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(m)	-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(n)	-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(o)	-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(p)	-Forty-First Supplemental Indenture dated June 6, 2002 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4.1 to the Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)	I
4(q)	-Forty-Second Supplemental Indenture dated March 12, 2004 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4(p) to the Form 10-K for the period ended December 31, 2004 filed on March 16, 2005)	I
4(r)	-Forty-Fourth Supplemental Indenture dated May 6, 2005 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4 to the Form 10-Q for the period ended March 31, 2005 filed on May 10, 2005)	I
4(s)	-Debt Securities 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(t)	-Securities Resolution No. 2 dated as of May 10, 2002 under Indenture dated as of August 1, 1998 between Western Resources, Inc. and Deutsche Bank Trust Company Americas (filed as Exhibit 4.2 to the Form 10-Q for the period ended March 31, 2002 filed on May 15, 2002)	I
4(u)	-Forty-Fifth Supplemental Indenture dated March 17, 2006 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee, to the Kansas Gas and Electric Company Mortgage and Deed of Trust dated April 1, 1940 (filed as Exhibit 4.1 to the Form 8-K filed on March 21, 2006)	I
4(v)	-Forty-Sixth Supplemental Indenture dated June 1, 2006 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee, to the Kansas Gas and Electric Company Mortgage and Deed of Trust dated April 1, 1940 (filed as Exhibit 4 to the Form 10-Q for the period ended June 30, 2006 filed on August 9, 2006)	I
4(w)	-Fortieth Supplemental Indenture dated May 15, 2007, between Westar Energy, Inc. and The Bank of	I

	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)	
4(x)	-Forty-Eighth Supplemental Indenture, dated as of July 10, 2007, by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(x) to the Form 10-K for the period ended December 31, 2007 filed on February 29, 2008)	I
4(y)	-Bond Purchase Agreement, dated as of August 14, 2007, between Kansas Gas and Electric Company and Nomura International PLC (filed as Exhibit 4.1 to the Form 8-K filed on August 15, 2007)	I
4(z)	-Forty-Ninth Supplemental Indenture, dated as of October 12, 2007, by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4.1 to the Form 8-K filed on October 19, 2007)	I
4(aa)	-Form of First Mortgage Bonds, 6.10% Series Due 2047 (contained in Exhibit 4(w))	I
4(ab)	-Bond Purchase Agreement dated as of May 15, 2008, between Kansas Gas and Electric Company and the Purchasers named therein (filed as Exhibit 4(1) to the Form 8-K filed on May 16, 2008)	I
4(ac)	-Fifty-First Supplemental Indenture, dated as of May 15, 2008 by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(2) to the Form 8-K filed on May 16, 2008)	I
4(ad)	-Fifty-Second Supplemental Indenture, dated as of August 1, 2008 by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(c) to the Form 10-Q for the period ended September 30, 2008 filed on November 6, 2008)	I
4(ae)	-Fifty-Third Supplemental Indenture, dated as of October 10, 2008 by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(d) to the Form 10-Q for the period ended September 30, 2008 filed on November 6, 2008)	I
4(af)	-Forty-First Supplemental Indenture, dated as of November 25, 2008 by and among Westar Energy, Inc., The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4.1 to the Form 8-K filed on November 24, 2008)	I
4(ag)	-Purchase Agreement, dated as of June 8, 2009, between Kansas Gas and Electric Company and and the Purchasers named therein (filed as Exhibit 4.1 to the Form 8-K/A filed on June 9, 2009)	I
4(ah)	-Fifty-Fourth Supplemental Indenture, dated as of June 11, 2009 by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(b) to the Form 10-Q for the period ended June 30, 2009 filed on August 6, 2009)	I
4(ai)	-Fifty-Fifth Supplemental Indenture, dated as of October 1, 2009 by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(a) to the Form 10-Q for the period ended September 30, 2009 filed on October 29, 2009)	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)	-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(b)	-Form of Employment Agreements with Messrs. Grennan, Koupal, Terrill, Lake and Wittig and Ms. Sharpe (filed as Exhibit 10(b) to the Form 10-K for the period ended December 31, 2000 filed on April 2, 2001)*	I
10(c)	-A Rail Transportation Agreement among Burlington Northern Railroad Company, the Union Pacific Railroad Company and Westar Energy, Inc. (filed as Exhibit 10 to the Form 10-Q for the period ended June 30, 1994 filed on August 11, 1994)	I
10(d)	-Agreement between Westar Energy, Inc. and AMAX Coal West Inc. effective March 31, 1993 (filed as Exhibit 10(a) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
10(e)	-Agreement between Westar Energy, Inc. and Williams Natural Gas Company dated October 1, 1993 (filed as Exhibit 10(b) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
10(f)	-Short-term Incentive Plan (filed as Exhibit 10(j) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)*	I
10(g)	-Westar Energy, Inc. Non-Employee Director Deferred Compensation Plan, as amended and restated, dated as of October 20, 2004 (filed as Exhibit 10.1 to the Form 8-K filed on October 21, 2004)*	I

10(h)	-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(i)	-Letter Agreement between Westar Energy, Inc. and David C. Wittig, dated April 27, 1995 (filed as Exhibit 10(m) to the Form 10-K for the period ended December 31, 1995 filed on March 27, 1996)*	I
10(j)	-Form of Split Dollar Insurance Agreement (filed as Exhibit 10.3 to the Form 10-Q for the period ended June 30, 1998 filed on August 12, 1998)*	I
10(k)	-Amendment to Letter Agreement between Westar Energy, Inc. and David C. Wittig, dated April 27, 1995 (filed as Exhibit 10 to the Form 10-Q/A for the period ended June 30, 1998 filed on August 24, 1998)*	I
10(l)	-Letter Agreement between Westar Energy, Inc. and Douglas T. Lake, dated August 17, 1998 (filed as Exhibit 10(n) to the Form 10-K405 for the period ended December 31, 1999 filed on March 29, 2000)*	I
10(m)	-Form of loan agreement with officers of Westar Energy, Inc. (filed as Exhibit 10(r) to the Form 10-K for the period ended December 31, 2001 filed on April 1, 2002)*	I
10(n)	-Amendment to Employment Agreement dated April 1, 2002 between Westar Energy, Inc. and David C. Wittig (filed as Exhibit 10.1 to the Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)*	I
10(o)	-Amendment to Employment Agreement dated April 1, 2002 between Westar Energy and Douglas T. Lake (filed as Exhibit 10.2 to the Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)*	I
10(p)	-Credit Agreement dated as of June 6, 2002 among Westar Energy, Inc., the lenders from time to time party there to, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent (filed as Exhibit 10.3 to the Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)	I
10(q)	-Employment Agreement dated September 23, 2002 between Westar Energy, Inc. and David C. Wittig (filed as Exhibit 10.1 to the Form 10-Q for the period ended September 30, 2002 filed on November 15, 2002)*	I
10(r)	-Employment Agreement dated September 23, 2002 between Westar Energy, Inc. and Douglas T. Lake (filed as Exhibit 10.1 to the Form 8-K filed on November 25, 2002)*	I
10(s)	-Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and James S. Haines, Jr. (filed as Exhibit 10(a) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)*	I
10(t)	-Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10(b) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)*	I
10(u)	-Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Mark A. Ruelle (filed as Exhibit 10(c) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)*	I
10(v)	-Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Douglas R. Sterbenz (filed as Exhibit 10(d) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)*	I
10(w)	-Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Larry D. Irick (filed as Exhibit 10(e) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)*	I
10(x)	-Waiver and Amendment, dated as of November 6, 2003, to the Credit Agreement, dated as of June 6, 2002, among Westar Energy, Inc., the Lenders from time to time party thereto, JPMorgan Chase Bank, as Administrative Agent for the Lenders, Citibank, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent (filed as Exhibit 10(f) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)	I
10(y)	-Credit Agreement dated as of March 12, 2004 among Westar Energy, Inc., the several banks and other financial institutions or entities from time to time parties to the Agreement, JPMorgan Chase Bank, as administrative agent, The Bank of New York, as syndication agent, and Citibank, N.A., Union Bank of California, N.A., and Wachovia Bank, National Association, as documentation agents (filed as Exhibit 10(a) to the Form 10-Q for the period ended March 31, 2004 filed on May 10, 2004)	I
10(z)	-Supplements and modifications to Credit Agreement dated as of March 12, 2004 among Westar Energy, Inc., as Borrower, the Several Lenders Party Thereto, JPMorgan Chase Bank, as	I

	Administrative Agent, The Bank of New York, as Syndication Agent, and Citibank, N.A., Union Bank of California, N.A., and Wachovia Bank, national Association, as Documentation Agents (filed as Exhibit 10(a) to the Form 10-Q for the period ended June 30, 2004 filed on August 4, 2004)	
10(aa)	-Purchase Agreement dated as of December 23, 2003 between POI Acquisition, L.L.C., Westar Industries, Inc. and Westar Energy, Inc. (filed as Exhibit 99.2 to the Form 8-K filed on December 24, 2003)	I
10(ab)	-Settlement Agreement dated November 12, 2004 by and among Westar Energy, Inc., Protection One, Inc., POI Acquisition, L.L.C., and POI Acquisition I, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on November 15, 2004)	I
10(ac)	-Restricted Share Unit Award Agreement between Westar Energy, Inc. and James S. Haines, Jr. (filed as Exhibit 10.1 to the Form 8-K filed on December 7, 2004)*	I
10(ad)	-Deferral Election Form of James S. Haines, Jr. (filed as Exhibit 10.2 to the Form 8-K filed on December 7, 2004)*	I
10(ae)	-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(af)	-Restricted Share Unit Award Agreement between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10.1 to the Form 8-K filed on December 29, 2004)*	I
10(ag)	-Deferral Election Form of William B. Moore (filed as Exhibit 10.2 to the Form 8-K filed on December 29, 2004)*	I
10(ah)	-Amended and Restated Credit Agreement dated as of May 6, 2005 among Westar Energy, Inc., the several banks and other financial institutions or entities from time to time parties to the Agreement, JPMorgan Chase Bank, N.A., as administrative agent, The Bank of New York, as syndication agent, and Citibank, N.A., Union Bank of California, N.A., and Wachovia Bank, National Association, as documentation agents (filed as Exhibit 10 to the Form 10-Q for the period ended March 31, 2005 filed on May 10, 2005)	I
10(ai)	-Amended and Restated Westar Energy Restricted Share Units Deferral Election Form for James S. Haines, Jr. (filed as Exhibit 10.1 to the Form 8-K filed on December 22, 2005)*	I
10(aj)	-Form of Change in Control Agreement (filed as Exhibit 10.1 to the Form 8-K filed on January 26, 2006)*	I
10(ak)	-Form of Amendment to the Employment Letter Agreements for Mr. Ruelle and Mr. Sterbenz (filed as Exhibit 10.2 to the Form 8-K filed on January 26, 2006)*	I
10(al)	-Form of Amendment to the Employment Letter Agreements for Mr. Irick and One Other Officer (filed as Exhibit 10.3 to the Form 8-K filed on January 26, 2006)*	I
10(am)	-Second Amended and Restated Credit Agreement, dated as of March 17, 2006, among Westar Energy, Inc., the 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 March 21, 2006)	I
10(an)	-Amendment to the Employment Letter Agreement for Mr. James S. Haines, Jr. (filed as Exhibit 99.3 to the Form 8-K filed on August 22, 2006)*	I
10(ao)	-Confirmation of Forward Sale Transaction, dated November 15, 2007, between UBS AG, London Branch and Westar Energy, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on November 16, 2007)	I
10(ap)	-Third Amended and Restated Credit Agreement dated as of February 22, 2008, 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 26, 2008)	I
10(aq)	-Westar Energy, Inc. Form of Restricted Share Units Award	#
10(ar)	-Westar Energy, Inc. Form of Performance Based Restricted Share Units Award	#
10(as)	-Westar Energy, Inc. Form of First Transition Performance Based Restricted Share Units Award	#
10(at)	-Westar Energy, Inc. Form of Second Transition Performance Based Restricted Share Units Award	#
10(au)	-Form of Amended and Restated Change in Control Agreement with Officers of Westar Energy, Inc.	#
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)	#
99(a)	-Kansas Corporation Commission Order dated November 8, 2002 (filed as Exhibit 99.2 to the Form 10-Q for the period ended September 30, 2002 filed on November 15, 2002)	I
99(b)	-Kansas Corporation Commission Order dated December 23, 2002 (filed as Exhibit 99.1 to the Form 8-K filed on December 27, 2002)	I
99(c)	-Debt Reduction and Restructuring Plan filed with the Kansas Corporation Commission on February 6, 2003 (filed as Exhibit 99.1 to the Form 8-K filed on February 6, 2003)	I
99(d)	-Kansas Corporation Commission Order dated February 10, 2003 (filed as Exhibit 99.1 to the Form 8-K filed on February 11, 2003)	I
99(e)	-Kansas Corporation Commission Order dated March 11, 2003 (filed as Exhibit 99(f) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003)	I
99(f)	-Demand for Arbitration (filed as Exhibit 99.1 to the Form 8-K filed on June 13, 2003)	I
99(g)	-Stipulation and Agreement filed with the Kansas Corporation Commission on July 21, 2003 (filed as Exhibit 99.1 to the Form 8-K filed on July 22, 2003)	I
99(h)	-Summary of Rate Application dated May 2, 2005 (filed as Exhibit 99.1 to the Form 8-KA filed on May 10, 2005)	I
99(i)	-Federal Energy Regulatory Commission Order On Proposed Mitigation Measures, Tariff Revisions, and Compliance Filings issued September 6, 2006 (filed as Exhibit 99.1 to the Form 8-K filed on September 12, 2006)	I
99(j)	-Stipulation and Agreement filed with the Kansas Corporation Commission on October 27, 2008 (filed as Exhibit 99.1 to the Form 8-K filed on October 27, 2008)	I
99(k)	-Civil complaint filed by the United States Department of Justice on February 4, 2009 (filed as Exhibit 99.1 to the Form 8-K filed on February 5, 2009)	I
99(l)	-Consent Decree with the United States Department of Justice and Appendix A thereto filed with the United States District Court for the District of Kansas on or about January 25, 2010 (filed as Exhibits 99.2 and 99.3, respectively, to the Form 8-K filed on January 25, 2010)	I

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, 2007				
Allowances deducted from assets for doubtful accounts.............................	$ 6,257	$ 3,273	$ (3,809)	$ 5,721
Year ended December 31, 2008				
Allowances deducted from assets for doubtful accounts.............................	$ 5,721	$ 3,580	$ (4,491)	$ 4,810
Year ended December 31, 2009				
Allowances deducted from assets for doubtful accounts.............................	$ 4,810	$ 5,797	$ (5,376)	$ 5,231

(a) Deductions are the result of write-offs of accounts receivable.

SIGNATURE

Pursuant to the requirements of Sections 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WESTAR ENERGY, INC.

Date: February 25, 2010

By: /s/ Mark A. Ruelle
Mark A. Ruelle,
Executive Vice President and
Chief Financial Officer

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/ WILLIAM B. MOORE (William B. Moore)	Director, President and Chief Executive Officer (Principal Executive Officer)	February 25, 2010
/s/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 25, 2010
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 25, 2010
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 25, 2010
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 25, 2010
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 25, 2010
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 25, 2010
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	February 25, 2010
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 25, 2010
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	February 25, 2010
/s/ JOHN C. NETTELS, JR. (John C. Nettels, Jr.)	Director	February 25, 2010