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

FORM 10-K

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

For the fiscal year ended December 31, 2008

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 First Mortgage Bonds, 6.10% Series due 2047	New York Stock Exchange 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 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 $2,324,082,258 at June 30, 2008.

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	108,484,553 shares
(Class)	(Outstanding at February 18, 2009)

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 2008 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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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 economic well-being of our customers.

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

- regulated and competitive markets,
- economic and capital market conditions, including the impact of changes in interest rates and the cost and availability of capital,
- inflation,
- execution of our planned capital expenditure program,
- performance of our generating plants,
- changes in accounting requirements and other accounting matters,
- changing weather,
- the impact of regional transmission organizations and independent system operators, including the development of market mechanisms for energy markets in which we participate,
- the impact of economic changes and downturns in the energy industry and the market for trading wholesale energy, including counter-party performance,
- the outcome of the lawsuit filed by the Department of Justice on behalf of the Environmental Protection Agency on February 4, 2009, alleging violations of the Clean Air Act, and developments related to environmental matters including possible future legislative or regulatory mandates related to emissions of presently unregulated gases or substances,
- political, legislative, judicial and regulatory developments at the municipal, state and federal level that can affect us or our industry, including in particular those relating to environmental laws,
- the impact of our potential liability to former executive officers for unpaid compensation and the impact of claims they have made against us related to the termination of their employment,
- the outcome of the Federal Energy Regulatory Commission investigation of our use of transmission service within the SPP,
- the impact of changes in interest rates on pension and other post-retirement and post-employment 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 decommissioning obligation,
- the impact of adverse changes in market conditions potentially resulting in the need for additional funding for the nuclear decommissioning and pension trusts,
- 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,
- coal, natural gas, uranium, diesel, oil and wholesale electricity prices,
- cost, availability and timely provision of equipment, supplies, labor and fuel we need to operate our business, and
- other circumstances affecting anticipated operations, sales and costs.

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. Any forward-looking statement speaks only as of the date such statement was made, and we are not obligated to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made except as required by applicable laws or regulations.

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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
2005 KCC Order	December 28, 2005, KCC Order
2009 KCC Order	January 21, 2009, KCC Order
AFUDC	Allowance for Funds Used During Construction
Aquila	Aquila, Inc.
BNSF	Burlington Northern Santa Fe
Btu	British Thermal Units
Central States Compact	Central Interstate Low-Level Radioactive Waste Compact
CO_2	Carbon Dioxide
COLI	Corporate-owned Life Insurance
DOE	Department of Energy
DOJ	Department of Justice
DSPP	Direct Stock Purchase Plan
ECRR	Environmental Cost Recovery Rider
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
ERISA	Employee Retirement Income Security Act
FASB	Financial Accounting Standards Board
February 2007 KCC Order	February 8, 2007, KCC Order
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation No.
Fitch	Fitch Investors Service
FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles
Guardian	Guardian International, Inc.
IRS	Internal Revenue Service
IRS Appeals Settlement	November 2008 tentative settlement with the IRS Office of Appeals
July 2006 Court Order	July 7, 2006, the Kansas Court of Appeals Order
July 2007 KCC Order	July 31, 2007, KCC Order
KCC	Kansas Corporation Commission
KCPL	Kansas City Power & Light Company
KDHE	Kansas Department of Health and Environment
KGE	Kansas Gas and Electric Company
kV	Kilovolt
La Cygne	La Cygne Generating Station
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	Megawatts
MWh	Megawatt hours
NEIL	Nuclear Electric Insurance Limited
NOx	Nitrogen Oxide
NRC	Nuclear Regulatory Commission

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NSR Investigation	EPA New Source Review Investigation
ONEOK	ONEOK, Inc.
OTC	Over-the-counter
PCB	Polychlorinated Biphenyl
PPA	Pension Protection Act
Prairie Wind Transmission	Prairie Wind Transmission, LLC
PRB	Powder River Basin
Protection One	Protection One, Inc.
RECA	Retail Energy Cost Adjustment
ROE	Return on Equity
RSUs	Restricted Share Units
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Group
SAB	Staff Accounting Bulletin
SEC	Securities and Exchange Commission
Section 114	Section 114(a) of the Clean Air Act
SFAS	Statement of Financial Accounting Standards
SPP	Southwest Power Pool
SSCGP	Southern Star Central Gas Pipeline
SO_2	Sulfur Dioxide
TDC	Transmission Delivery Charge
VaR	Value-at-Risk
WCNOC	Wolf Creek Nuclear Operating Corporation
Wolf Creek	Wolf Creek Generating Station

PART I

ITEM 1. BUSINESS

GENERAL

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 679,000 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.

SIGNIFICANT BUSINESS DEVELOPMENTS

Changes in Rates

We filed an application with the Kansas Corporation Commission (KCC) in May 2008 to increase retail rates by $177.6 million per year. The primary drivers for this application were investments in natural gas generation facilities, wind generation facilities and other capital projects, costs attributable to the 2007 ice storm, higher operating costs and an update of our capital structure. On October 27, 2008, all parties to the proceeding filed an agreement with the KCC supporting a $130.0 million annual increase in our retail rates. On January 21, 2009, the KCC issued an order approving the settlement agreement and the new retail rates became effective on February 3, 2009.

The KCC and Federal Energy Regulatory Commission (FERC) also adjust our rates through the use of rate mechanisms 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."

Economic Conditions

Global and U.S. economic conditions throughout 2008 have begun to impact certain of our industrial and commercial customers and may affect our residential business. Kansas companies are experiencing reduced production and have announced significant employee layoffs. Kansas is experiencing an increase in unemployment claims and the unemployment rate. We cannot determine when these conditions may reverse or whether and to what extent they may affect our results of operations.

Tax Settlements

In February 2008, we reached a settlement with the Internal Revenue Service (IRS) on issues principally related to the method used to capitalize overheads to electric plant for years 1995 through 2002. This settlement resulted in a 2008 net earnings benefit of approximately $39.4 million, including interest, due to the recognition of previously unrecognized tax benefits. The recognition of these previously unrecognized tax benefits resulted in earnings of $0.38 per share for the year ended December 31, 2008.

In January 2009, we reached a settlement with the IRS associated with the re-characterization of the loss we incurred on the sale of Protection One, Inc. (Protection One) from a capital loss to an ordinary loss. This settlement will result in a first quarter 2009 net earnings benefit from discontinued operations of approximately $32.5 million due to the recognition of previously unrecognized tax benefits in accordance with the provisions of Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48, “Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109.”

New Construction Plans

We are making and will continue to make significant investments in new generation, new transmission and air emission controls at existing fossil-fueled power plants.

During 2008, we made capital expenditures of $257.2 million at our power plants for air emission controls. We have identified the potential for us to make up to an additional $1.3 billion of capital expenditures at our power plants for air emissions projects over the next six years.

We have been working with third parties to develop approximately 300 megawatts (MW) of wind generation facilities at three different sites in Kansas. Under the terms of the agreements, we will own approximately half of the wind generation facilities at an expected cost of approximately $282.0 million and will purchase energy produced by the wind generation facilities under twenty year supply contracts for the other half. One of the facilities from which we purchase energy began producing energy in December 2008 and we expect the other two to begin producing energy in early 2009.

On February 12, 2009, we announced that we are seeking bids for as much as 500 MW of additional renewable energy resources. We requested bids contemplating for potentially up to 200 MW of the generation being online by late 2010 with the remainder being potentially online by late 2013. We and our regulators have not yet concluded whether any additional renewable resources will be added.

We are constructing a 345 kilovolt (kV) transmission line from our Gordon Evans Energy Center northwest of Wichita, Kansas, to a new substation near Hutchinson, Kansas, then on to our Summit substation near Salina, Kansas, a distance totaling approximately 100 miles. We completed construction of the first segment in December 2008 and expect the second segment to be completed by June 2010. We expect the total investment in the line and substations to be approximately $200.0 million.

In addition to the transmission line described above, we also plan to construct a new 345 kV line from a substation near Wichita to the Kansas-Oklahoma border, where we will interconnect with new facilities being built by an Oklahoma utility. The preliminary estimate of the investment in the line is approximately $90.0 million, which is subject to change pending final engineering design, labor and materials, among other factors. We expect to begin construction in 2010.

In 2008, we completed the first phase of our Emporia Energy Center, a new natural gas-fired peaking power plant consisting of seven combustion turbines located near Emporia in Lyon County, Kansas, comprising approximately 350 MW of capacity. We expect to complete construction of the second phase, consisting of two generating units that will add an additional approximately 320 MW of generating capacity, early in 2009 for a total investment of about $318.0 million.

In May 2008, we and Electric Transmission America, LLC formed Prairie Wind Transmission, LLC (Prairie Wind Transmission), a joint venture company of which we own 50%. Prairie Wind Transmission is proposing to construct approximately 230 miles of 765 kV transmission facilities in Kansas extending west from near Wichita to near Dodge City and then south-southwest to the Kansas-Oklahoma border. On December 2, 2008, FERC approved a number of key rate components related to these transmission facilities and set aside for hearing the establishment of a formula rate and associated protocols. Should Prairie Wind Transmission receive the necessary regulatory approvals from the KCC and FERC, the facilities are expected to be in service by the end of 2013, contingent on a number of factors including the availability and cost of capital, not all of which are under our control. We will incur significant future capital expenditures related to this joint venture if Prairie Wind Transmission receives regulatory approval to build the transmission facilities.

OPERATIONS

General

Westar Energy supplies electric energy at retail to approximately 366,000 customers in central and northeast Kansas and KGE supplies electric energy at retail to approximately 313,000 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 pursuant to contracts of various lengths. 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 our retail service territory.

We have a retail energy cost adjustment (RECA) that allows us to recover the cost of fuel consumed in generating electricity and purchased power needed to serve most of our retail customers. As a result of the January 21, 2009, KCC Order (2009 KCC Order), we will bill our customers for fuel on a quarter ahead estimate beginning approximately March 1, 2009. 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 mechanism as the means by which we refund to customers the margins realized from market-based wholesale sales.

Generation Capacity

We have 6,508 MW of accredited generating capacity in service, of which 2,578 MW is owned or leased by KGE. See “Item 2. Properties” for additional information on our generating units. The capacity by fuel type is summarized below.

Fuel Type	Capacity (MW)	Percent of Total Capacity
Coal	3,432	52.7
Nuclear	545	8.4
Natural gas or oil	2,450	37.7
Diesel	81	1.2
Total	6,508	100.0

Our aggregate 2008 peak system net load of 4,754 MW occurred on August 4, 2008. This included 107 MW of potentially interruptible load. Our net generating capacity, combined with firm capacity purchases and sales and the ability to interrupt 107 MW of load, provided a capacity margin of 18% above system peak responsibility at the time of our 2008 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.	130	October 2013
Kansas Electric Power Cooperative	187	December 2009
Midwest Energy, Inc.	125	May 2010
Empire District Electric Company	162	May 2010
Oklahoma Municipal Power Authority	60	December 2013
ONEOK Energy Services Co.	75	December 2015
Mid-Kansas Electric Company, LLC	175	January 2019
Total	914	

(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 2008, 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.

Fossil Fuel Generation

Fuel 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 2008 fuel mix was 79% coal, 13% nuclear and 7% natural gas, with diesel and oil making up less than 1%. In 2009 we expect to use higher percentages of coal and nuclear as we do not expect to experience extended outages at our coal plants or Wolf Creek in 2009. There were extended outages at some of our coal plants and Wolf Creek in 2008. As a result of our new wind generation facilities, 2009 will be the first year in which we expect to produce a significant amount of wind energy. Our fuel 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.

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. We made a scheduled re-pricing in 2008. 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 rail carriers. 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 burned at Jeffrey Energy Center during 2008 was approximately $1.57 per MMBtu, or $26.25 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 local 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 La Cygne 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 December 31, 2010. As the PRB coal contracts expire, we anticipate that KCPL will negotiate new supply contracts or purchase coal on the spot market.

During 2008, the average delivered cost of all coal burned at La Cygne unit 1 was approximately $1.31 per MMBtu, or $21.24 per ton. The average delivered cost of coal burned at La Cygne unit 2 was approximately $1.18 per MMBtu, or $19.65 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 770 MW. We purchase coal under a contract with Arch Coal, Inc. (Arch). The current contract with Arch is expected to provide 100% of the coal requirement for these energy centers through 2010.

BNSF transported coal for these energy centers from Wyoming under a contract that expired in December 2008. We have reached a mutual agreement of understanding with BNSF for the continuing provision of coal transportation to these energy centers until we finalize a long-term contract.

During 2008, the average delivered cost of all coal burned in the Lawrence units was approximately $1.22 per MMBtu, or $21.56 per ton. The average delivered cost of all coal burned in the Tecumseh units was approximately $1.24 per MMBtu, or $21.86 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 2008, we purchased 22.1 million MMBtu of natural gas for a total cost of $172.0 million. Natural gas accounted for approximately 7% of our total MMBtu of fuel burned during 2008 and approximately 31% 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, 2009. 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 has been restructured and extended through April 1, 2020. The agreement for the State Line facility extends through June 1, 2016, 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 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 only burn No. 6 oil when natural gas is unavailable. During 2008, we did not burn any 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, to satisfy emergency requirements and to protect against reduced availability of natural gas for limited periods.

During 2008, we burned 0.3 million MMBtu of diesel at a total cost of $5.6 million. Diesel accounted for less than 1% of our total MMBtu of fuel burned during 2008 and approximately 1% of our total fuel expense. For additional information on our exposure to commodity price risks, see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

Other Fuel Matters

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

	2008	2007	2006
Per MMBtu:			
Nuclear	$ 0.44	$ 0.43	$ 0.41
Coal	1.42	1.27	1.25
Natural gas	7.77	6.51	6.49
Diesel/oil	21.01	15.18	9.19
Per MWh Generation:			
Nuclear	$ 4.57	$ 4.46	$ 4.28
Coal	15.75	13.92	13.69
Natural gas/diesel/oil	79.50	67.65	66.91
All generating stations	18.99	15.51	14.94

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. Purchased power for the year ended December 31, 2008, comprised approximately 20% of our total fuel and purchased power expenses. The weighted average cost of purchased power was $58.96 per megawatt hour (MWh) in 2008, $61.04 per MWh in 2007 and $54.90 per MWh in 2006.

Energy Marketing Activities

We engage in both financial and physical trading with the objective of increasing profits, managing commodity price risk and enhancing system reliability. We trade electricity and other energy-related products using a variety of financial instruments, including future contracts, options and swaps, and we trade energy commodity contracts.

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, with Kansas Electric Power Cooperative, Inc. holding the remaining 6% interest. The co-owners pay operating costs equal to their percentage ownership in Wolf Creek.

In September 2006, Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, filed a request with the Nuclear Regulatory Commission (NRC) for a 20-year extension of Wolf Creek's operating license. In November 2008, the NRC approved WCNOC's request and Wolf Creek's operating license was extended until 2045.

Fuel Supply

The owners of Wolf Creek have on hand or under contract all of the uranium and conversion services needed to operate Wolf Creek through March 2011 and approximately 87% of uranium and conversion services after that date through September 2018. The owners also have under contract 100% of the uranium enrichment and fabrication required to operate Wolf Creek through March 2025.

Because of a production delay at a mine from which Wolf Creek expected to receive future supplies of uranium, it is possible that contracted uranium deliveries scheduled for 2010 and some years beyond could be reduced, necessitating an increase in the amount of uranium planned for purchase in those years. Wolf Creek's on-going operations strategies, including previous acquisition of inventory, are expected to minimize the impact of such reductions.

We have entered into all uranium, uranium conversion and uranium enrichment arrangements, as well as the fabrication agreements, in the ordinary course of business. We believe Wolf Creek is not substantially dependent on these agreements.

Radioactive Waste Disposal

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 was $3.5 million in 2008, $4.4 million in 2007 and $4.1 million in 2006 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers. We include these costs in fuel and purchased power expense.

In 2002, the Yucca Mountain site in Nevada was approved for the development of a nuclear waste repository for the disposal of spent nuclear fuel and high level nuclear waste from the nation's defense activities. This action allows the DOE to apply to the NRC to license the project. On June 3, 2008, the DOE submitted a license application to the NRC seeking authorization to construct the nuclear waste repository at the Yucca Mountain site. The opening of the Yucca Mountain site has been delayed many times and could be delayed further due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel. Wolf Creek has on-site temporary storage for spent nuclear fuel expected to be generated by Wolf Creek through 2025.

Wolf Creek disposes of all classes of its low-level radioactive waste at existing third-party repositories. One of those repositories was located in Barnwell, South Carolina. However, as of July 1, 2008, the State of South Carolina no longer accepts waste from generators other than those located in South Carolina, Connecticut, and New Jersey – the three states that make up the Atlantic Interstate Low-Level Radioactive Waste Management Compact. We expect that another site in the state of Utah will remain available to Wolf Creek. Should disposal capability become unavailable, we believe Wolf Creek is able to store its low-level radioactive waste in an on-site facility. We believe that a temporary loss of low-level radioactive waste disposal capability would not affect Wolf Creek's continued operation.

The Low-Level Radioactive Waste Policy Amendments Act of 1985 mandated that the various states, individually or through interstate compacts, develop alternative low-level radioactive waste disposal facilities. The states of Kansas, Nebraska, Arkansas, Louisiana and Oklahoma formed the Central Interstate Low-Level Radioactive Waste Compact (Central States Compact), and the Central States Compact Commission, which is responsible for creating new disposal capability for the member states. The Central States Compact Commission selected Nebraska as the host state for the disposal facility. An initial effort in the 1990s to license the construction of a disposal facility in Nebraska failed and the Central States Compact Commission revoked Nebraska's membership in the Central States Compact. There has not been another effort to develop a disposal facility in the Central States Compact region.

Outages

Wolf Creek operates on an 18-month planned refueling and maintenance outage schedule. Wolf Creek was shut down for 55 days in 2008 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 provided by the KCC, we defer and amortize evenly the incremental maintenance costs incurred for planned refueling outages over the unit's 18-month operating cycle. Wolf Creek is next scheduled to be taken off-line in the fall of 2009 for refueling and maintenance.

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 other 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 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 and dismantlement study with the KCC every three years. The next review is scheduled to occur in 2009.

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” 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. The actual nuclear decommissioning costs may vary from the estimates because of changes in regulations, technologies and changes in costs for labor, materials and equipment.

Electric rates charged to customers provide for recovery of these nuclear decommissioning costs over the life of Wolf Creek, which is through 2045. The NRC requires that funds to meet its nuclear decommissioning funding assurance requirement be in our nuclear decommissioning fund by the time our operating license expires in 2045. We believe that the KCC approved funding level will also be sufficient to meet the NRC minimum financial assurance requirement. Our consolidated results of operations would be materially adversely affected if we were not allowed to recover in utility rates the full amount of the funding requirement.

We recovered in rates and deposited in an external trust fund for nuclear decommissioning approximately $2.9 million in 2008 and 2007 and $3.9 million in 2006. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $85.6 million as of December 31, 2008 and $122.3 million as of December 31, 2007. During 2008, the value of these financial assets declined significantly. As a result, we will likely have to contribute additional amounts to the nuclear decommissioning fund. We expect to collect those amounts from our customers.

Competition and Deregulation

FERC requires owners of regulated transmission assets to allow third party wholesale providers of electricity nondiscriminatory access to their transmission systems to transport electric power to wholesale customers. FERC also requires us to provide transmission services to others under terms comparable to those we allow ourselves. Furthermore, FERC issued an order encouraging the formation of regional transmission organizations (RTO). RTOs are designed to control the wholesale transmission services of the utilities in their regions, thereby facilitating competitive wholesale power markets.

Regional Transmission Organization

We are a member of the Southwest Power Pool (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 eight states. The SPP collects revenues for the use of each transmission owner’s transmission system. Transmission customers transmit throughout the entire SPP system power purchased and generated for sale or bought for resale in the wholesale market. 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.

Real-Time Energy Imbalance Market

On February 1, 2007, the SPP implemented the real-time energy imbalance market as required by FERC to accommodate financial settlement of energy imbalances within the SPP region. The objective of the 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 economical purchase and sale of excess energy maximizing the available transmission system. The company participates in this market.

Regulation and Rates

Kansas law gives the KCC general regulatory authority over our rates, 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.

FERC Proceedings

Requests for Changes in Transmission Rates

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 (ROE) and a 15-year accelerated recovery for an approximately 100 mile, 345 kV 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 by June 2010. We estimate the line will cost approximately $200.0 million.

In November 2007, we filed applications with FERC that proposed changes in the capital structure used in our transmission formula rate. FERC accepted the proposed changes and the rate change went into effect on June 1, 2007. At December 31, 2008, we had a $2.8 million refund obligation related to this matter, which includes the amount we have collected since June 1, 2007, plus interest on that amount.

On May 2, 2005, we filed applications with FERC that proposed a transmission formula rate providing for annual adjustments to our transmission tariff. This is consistent with our proposals filed with the KCC on May 2, 2005, to charge retail customers separately for transmission service through a transmission delivery charge (TDC). In November 2007, FERC approved a settlement providing for the rate change effective December 1, 2005, and a refund to customers of $3.4 million.

Request for Increase in Revolving Credit Facility

On January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to pledge KGE mortgage bonds in order to increase the size of Westar Energy’s revolving credit facility to $750.0 million. On February 15, 2008, FERC granted our request. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Resources” for more information.

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 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 rates. 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 rates of capital investments related directly to environmental improvements required by the Clean Air Act as well as many of the costs related to compliance with other environmental laws and regulations. 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 statements.

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 two-phase reduction in certain emissions. 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 2008, we had SO_2 allowances adequate to meet planned generation and we expect to have enough in 2009. In the future if we need to purchase additional allowances our operating costs would increase. We expect to recover the cost of emission allowances through the RECA although there are no guarantees we will be able to do so. The price of emissions allowances is determined by market forces and changes over time.

On February 28, 2008, we reached an agreement with the KDHE to implement a plan to improve efficiency and to install new equipment to reduce regulated emissions from Jeffrey Energy Center. The projects are designed to meet requirements of the Clean Air Visibility Rule and reduce emissions over our entire generating fleet by eliminating more than 70% of SO_2 and reducing nitrous oxides between 50% and 65%.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule. Beginning in 2010, the rule caps permanently and reduces the amount of mercury that may be emitted from coal-fired power plants. However, on February 8, 2008, the U.S. District Court of Appeals for the District of Columbia vacated the Clean Air Mercury Rule. While the ultimate impact of this ruling on our operations is currently unknown, we believe that mercury emissions controls may be required in the future and that the costs to comply with these requirements may be material.

Environmental requirements have been changing substantially. 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,
- additional legislation introduced in the past few years in Congress requiring reductions of presently unregulated gases related primarily to concerns about climate change, and
- state legislation introduced recently that could require mitigation of CO_2 emissions.

Based on currently available information, we cannot estimate our costs to comply with these proposed laws, but we believe such costs could be material.

Environmental Costs

We have identified the potential for us to make up to $1.3 billion of capital expenditures at our power plants for environmental air emissions projects during the next six years. This estimate could materially increase or decrease depending on the timing and the nature of required investments, the specific outcomes resulting from interpretation of existing regulations, new regulations, legislation and the resolution of the EPA New Source Review Investigation (NSR Investigation) and the related Department of Justice (DOJ) lawsuit described below. In addition to the capital investment, in the event we install new equipment as a result of the NSR Investigation and the related DOJ lawsuit, such equipment may cause us to incur significant increases in annual operating and maintenance expense and may reduce net production from our power plants. The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. In addition, 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.

The ECRR allows for the more timely inclusion in retail rates of capital expenditures tied directly to environmental improvements, including those required by the Clean Air Act. However, increased operating and maintenance costs, other than expenses related to production-related consumables, can be recovered only through a change in base rates.

New Source Review Investigation

Under Section 114(a) of the Clean Air Act (Section 114), 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.

The EPA requested information from us under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at three coal-fired plants we operate. 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 DOJ filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. A decision in favor of the DOJ and the EPA, or a settlement prior to such a decision, if reached, could require us to update or install emissions controls at Jeffrey Energy Center. Additionally, we might 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 NSR Investigation and the related DOJ lawsuit could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery in the prices we are allowed to charge our customers. If, however, a penalty is assessed against us, the penalty could be material and may not be recovered in rates. We are not able to estimate the possible loss or range of loss at this time.

Manufactured Gas Sites

We have been identified as being responsible for the clean-up of a number of former manufactured gas sites located in Kansas and Missouri. We and the KDHE entered into a consent agreement in 1994 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 sales are seasonal. The third quarter typically accounts for our greatest sales. Sales volumes are affected by weather conditions, the economy of our service territory and the performance of our customers.

EMPLOYEES

As of February 18, 2009, we had 2,415 employees. In 2008, we negotiated a three-year contract with Local 304 and Local 1523 of the International Brotherhood of Electrical Workers that extends through June 30, 2011. The contract covered 1,343 employees as of February 18, 2009.

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 Securities and Exchange Commission (SEC). The information contained on our Internet website is not part of this document.

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EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During the Past Five Years
William B. Moore	56	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	50	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	47	Executive Vice President and Chief Financial Officer (since January 2003)	
Douglas R. Sterbenz	45	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	50	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	52	Vice President, General Counsel and Corporate Secretary (since February 2003)	
Michael Lennen	63	Vice President, Regulatory Affairs (since July 2007)	**Morris, Laing, Evans, Brock & Kennedy, Chartered** Partner (January 1990 to July 2007)
Lee Wages	60	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

Like other companies in our industry, our consolidated financial results will be impacted by weather, the economy of our service territory and the energy use of our customers. The value of our common stock and our creditworthiness will be affected by national and international macroeconomic trends, general market conditions and the expectations of the investment community, all of which are largely beyond our control. In addition, the following statements highlight risk factors that may affect our consolidated financial statements. These 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.

Our Revenues Depend Upon Rates Determined by the KCC and FERC

The KCC and FERC regulate many aspects of our business and operations, including the rates that we charge customers for electric service. Retail rates are set by the KCC while wholesale and transmission rates are set by FERC. Both the KCC and FERC use a cost-of-service approach that takes into account historical operating expenses, fixed obligations and recovery of and a return on capital investments. Using this approach, the KCC and FERC set rates at a level calculated to recover such costs and a permitted return on investment. On January 21, 2009, the KCC authorized a $130.0 million increase in our retail rates to reflect our investment in natural gas generation facilities, wind generation facilities and other capital projects, costs attributable to the 2007 ice storm, higher operating costs and an update of our capital structure. The new retail rates became effective on February 3, 2009.

Our Costs May Not be Fully Recovered in Rates

Except to the extent the KCC and FERC permit us to modify our prices by using specific adjustments and riders, such as the RECA, TDC and ECRR, our rates generally remain fixed until changed in a subsequent rate review. We may apply to change our rates or intervening parties may request that our rates be reviewed for possible adjustment.

Equipment Failures and Other External Factors Can Adversely Affect Our Results

The generation and transmission of electricity requires the use of expensive and complicated equipment. While we have maintenance programs in place, generating plants are subject to extended or unplanned outages because of equipment failure, weather, failure by our contractors or subcontractors to meet commitments and other factors largely beyond our control. In such events, we must either produce replacement power from our other, usually less efficient, units or purchase power from others at unpredictable and potentially higher costs in order to meet our sales obligations. In addition, such events can limit our ability to make opportunistic sales to wholesale customers.

Fuel Deliveries Can Be Interrupted or Slowed and Transmission Systems May Be Constrained

Coal deliveries from the PRB region of Wyoming, the primary source for our coal, can be interrupted or can be slowed due to rail traffic congestion, equipment or track failure or loading problems at the mines. This may require that we implement coal conservation efforts and/or take other compensating measures. We experienced these problems and conserved coal to varying degrees in 2006. These measures may include, but are not limited to, reducing coal consumption by revising normal dispatch of generation units, purchasing power or using more expensive power to serve customers and decreasing or, if necessary, eliminating opportunistic wholesale sales. In addition, decisions or mistakes by other utilities may adversely affect our ability to use transmission lines to deliver or import power, thus subjecting us to unexpected expenses or to the cost and uncertainty of public policy initiatives. These factors, along with the prices and price volatility of fuel and wholesale electricity are largely beyond our control. Costs that are not recovered through the RECA could have a material adverse effect on our consolidated financial statements. We engage in energy marketing transactions to reduce risk from market fluctuations, enhance system reliability and increase profits. The events mentioned above could reduce our ability to participate in energy marketing opportunities, which could reduce our profits.

We May Have Material Financial Exposure Relating to Environmental Matters

Under Section 114, 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.

The EPA requested information from us under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at three coal-fired plants we operate. 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 DOJ filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. A decision in favor of the DOJ and the EPA, or a settlement prior to such a decision, if reached, could require us to update or install emissions controls at Jeffrey Energy Center. Additionally, we might 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 NSR Investigation and the related DOJ lawsuit could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery in the prices we are allowed to charge our customers. If, however, a penalty is assessed against us, the penalty could be material and may not be recovered in rates. We are not able to estimate the possible loss or range of loss at this time.

Our activities are subject to extensive and changing environmental regulation by federal, state and local governmental authorities, particularly relating to air emissions. In addition to laws currently in effect, numerous laws and regulations have been enacted and proposed relating to increasing national and international concern about possible global warming caused by the atmospheric release of CO_2 and other gases by industrial and other sources, including the utility industry. On November 15, 2007, the governors of six Midwestern states, including Kansas, signed the Midwest Greenhouse Gas Reduction Accord, under which the member states will, among other things, establish greenhouse gas reduction targets and develop a market-based and multi-sector cap-and-trade mechanism to help achieve such targets. In addition, on October 18, 2007, the KDHE denied an application by an unrelated utility for an air quality permit for two new proposed coal generators in Western Kansas in part because of concerns about the increase in CO_2 and emissions and the potential ill effects those plants might have on the environment and health. The KDHE noted that the decision constituted a first step in emerging policy to address existing and future CO_2 emissions in Kansas. The Midwest Greenhouse Gas Reduction Accord or other new or changed laws and regulations, as well as third party litigation that may be brought against us or our competitors, could result in requirements to install costly equipment, increase our operating expenses, reduce production from our plants or take other actions we are unable to identify at this time.

The degree to which we may need to reduce emissions and the timing of when such emissions control equipment may be required is uncertain. Both the timing and the nature of required investments depend on specific outcomes that result from interpretation of existing regulations, new regulations, legislation and the resolution of the NSR Investigation and the related DOJ lawsuit described above. Although we expect to recover in our rates most of the costs that we incur to comply with environmental regulations, we can provide no assurance that we will be able to fully and timely recover such costs or the costs of any failure to comply with laws and regulations. Failure to recover these associated costs could have a material adverse effect on our consolidated financial statements.

Accounting Regulations Unique to Public Utilities Could Change

We currently apply the accounting principles of Statement of Financial Accounting Standard (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," to our regulated business. As of December 31, 2008, we had recorded $829.2 million of regulatory assets, net of regulatory liabilities. In the event we determined that we could no longer apply the principles of SFAS No. 71, 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 periodically review these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Based upon current evaluation of the various factors that are expected to impact future cost recovery, we believe that our regulatory assets are probable of recovery.

We Face Financial Risks Associated With Wolf Creek

Risks of substantial liability arise from the ownership and operation of nuclear facilities, including, among others, structural problems at a nuclear facility, the storage, handling and disposal of radioactive materials, limitations on the amounts and types of insurance coverage commercially available, uncertainties with respect to the cost and technological aspects of nuclear decommissioning at the end of their useful lives and costs or measures associated with public safety. 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 we would have less power available for sale into the wholesale markets. If we were not permitted by the KCC to recover these costs, such events would likely have an adverse impact on our consolidated financial statements.

Our Planned Capital Expenditures Are Significant To Our Results Of Operations

During the period from 2009 through 2011 and for the immediate years beyond, we plan to continue significant capital expenditures toward large projects including the expansion and modernization of our generation fleet and transmission network. Our anticipated capital expenditures for the period from 2009 through 2011, including costs of removal, are approximately $2.4 billion. Delays in engineering and construction times can occur throughout our industry. Because our capital expenditure program is large in comparison to our revenues and assets, cost increases or delays could materially affect our consolidated financial statements.

In addition, in order to fund our capital expenditure program, we rely to a large degree on access to our short-term credit facility and to long-term capital markets for debt and equity as sources of liquidity for capital requirements not satisfied by the cash flow from our operations. The secured and unsecured debt of Westar Energy and KGE are rated investment grade by all three of the best known rating agencies, but we cannot assure that such debt will continue to be rated investment grade. If the rating agencies were to downgrade Westar Energy's or KGE's secured or unsecured debt, our borrowing costs and the interest rates we pay on short-term and long-term debt would likely increase, possibly significantly. Further, market disruptions could increase our cost of borrowing or adversely affect our ability to access financial markets. Additional issuance of equity securities could dilute the value of our shares of our common stock and cause the market price of our common stock to fall. These factors could hinder our access to capital markets and limit or delay our ability to carry out our capital expenditure program.

Further, our recovery of capital expenditures depends in large degree on the outcome of retail and wholesale rate proceedings. Decisions made by the KCC or FERC, or delays in making such decisions, could have a material impact on our consolidated financial statements.

Uncertainty in the Credit Markets and the Impact on the Economy in Our Service Territory

Continuing turmoil in the global credit markets, and the slowing of the global and U.S. economies, may have a number of effects on our operations, financial condition and capital expenditure program. While we cannot provide an exhaustive list of all possible effects, these market conditions may make capital more difficult and costly to obtain; may restrict liquidity available to us through our revolving credit facility; may reduce demand by our customers and increase delinquencies or non-payment by our customers; may adversely impact the financial condition of our suppliers, which may in turn limit our access to inventory or capital equipment; may reduce the credit available to our energy trading counterparties and correspondingly reduce our energy trading activity or increase our exposure to counterparty default; may require us to defer or limit elements of our capital expenditure program; may reduce the value of our financial assets and correspondingly adversely impact our earnings and net cash flow; may require us to provide additional funding to our nuclear decommissioning and pension trusts; and may increase the cost or decrease the availability of insurance to us or make insurance claims more difficult to collect. These and other related effects may have an adverse impact on our consolidated financial statements and in extreme circumstances, the combination of some or all of these effects might impact amounts available for the payment of dividends.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Name	Location	Unit No.		Year Installed	Principal Fuel	Unit Capacity (MW) By Owner		
						Westar Energy	KGE	Total Company
Abilene Energy Center:	Abilene, Kansas							
Combustion Turbine		1		1973	Gas	72	—	72
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
Gordon Evans Energy Center:	Colwich, Kansas							
Steam Turbines		1		1961	Gas—Oil	—	152	152
		2		1967	Gas—Oil	—	384	384
Combustion Turbines		1		2000	Gas	74	—	74
		2		2000	Gas	72	—	72
		3		2001	Gas	150	—	150
Diesel Generator		1		1969	Diesel	—	3	3
Hutchinson Energy Center:	Hutchinson, Kansas							
Steam Turbine		4		1965	Gas—Oil	170	—	170
Combustion Turbines		1		1974	Gas	56	—	56
		2		1974	Gas	51	—	51
		3		1974	Gas	56	—	56
		4		1975	Diesel	75	—	75
Diesel Generator		1		1983	Diesel	3	—	3
Jeffrey Energy Center (92%):	St. Marys, Kansas							
Steam Turbines		1	(a)	1978	Coal	521	144	665
		2	(a)	1980	Coal	517	144	661
		3	(a)	1983	Coal	521	144	665
La Cygne Station (50%):	La Cygne, Kansas							
Steam Turbines		1	(a)	1973	Coal	—	368	368
		2	(b)	1977	Coal	—	341	341
Lawrence Energy Center:	Lawrence, Kansas							
Steam Turbines		3		1954	Coal	49	—	49
		4		1960	Coal	108	—	108
		5		1971	Coal	373	—	373
Murray Gill Energy Center:	Wichita, Kansas							
Steam Turbines		1		1952	Gas	—	39	39
		2		1954	Gas—Oil	—	53	53
		3		1956	Gas—Oil	—	101	101
		4		1959	Gas—Oil	—	93	93
Neosho Energy Center:	Parsons, Kansas							
Steam Turbine		3		1954	Gas—Oil	—	67	67
Spring Creek Energy Center:	Edmond, Oklahoma							
Combustion Turbines		1		2001 (c)	Gas	70	—	70
		2		2001 (c)	Gas	69	—	69
		3		2001 (c)	Gas	67	—	67
		4		2001 (c)	Gas	68	—	68
State Line (40%):	Joplin, Missouri							
Combined Cycle		2-1	(a)	2001	Gas	65	—	65
		2-2	(a)	2001	Gas	65	—	65
		2-3	(a)	2001	Gas	74	—	74
Tecumseh Energy Center:	Tecumseh, Kansas							
Steam Turbines		7		1957	Coal	72	—	72
		8		1962	Coal	130	—	130
Combustion Turbines		1		1972	Gas	19	—	19
		2		1972	Gas	19	—	19
Wolf Creek Generating Station (47%):	Burlington, Kansas							
Nuclear		1	(a)	1985	Uranium	—	545	545
Total						3,930	2,578	6,508

(a) 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.

(b) In 1987, KGE entered into a sale-leaseback transaction involving its 50% interest in the La Cygne unit 2 generating unit.

(c) 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 4,100 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 –New Source Review Investigation" and "Legal Proceedings", respectively, which are incorporated herein by reference.

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

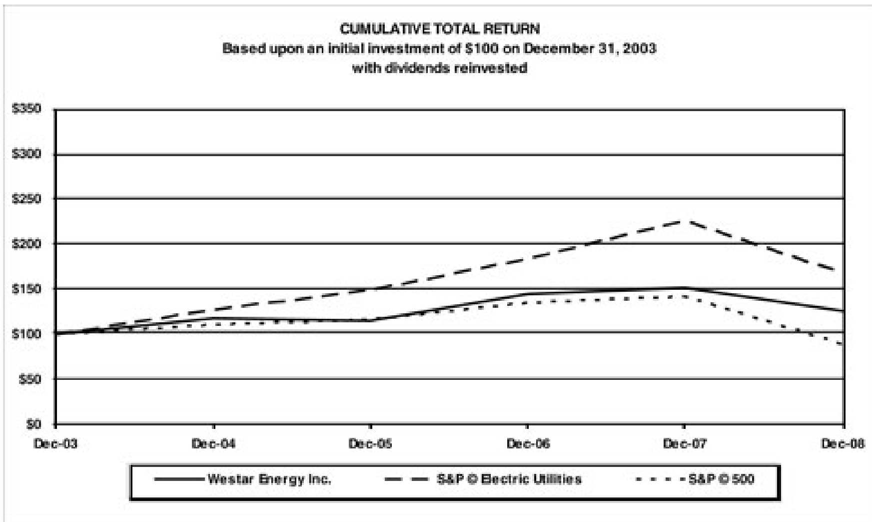
None.

PART II

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

STOCK PERFORMANCE GRAPH

The following performance graph compares the performance of our common stock during the period that began on December 31, 2003, and ended on December 31, 2008, to the Standard & Poor's 500 Index and the Standard & Poor's Electric Utility Index. The graph assumes a $100 investment in our 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-2003	Dec-2004	Dec-2005	Dec-2006	Dec-2007	Dec-2008
Westar Energy Inc.	$100	$117	$115	$145	$151	$126
S&P 500	$100	$111	$116	$135	$142	$90
S&P Electric Utilities	$100	$127	$149	$183	$226	$168

STOCK TRADING

Our common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 18, 2009, there were 23,822 common shareholders of record. For information regarding quarterly common stock price ranges for 2008 and 2007, see Note 20 of the Notes to Consolidated Financial Statements, "Quarterly Results (Unaudited)."

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DIVIDENDS

Holders of our common stock are entitled to dividends when and as declared by our board of directors. However, prior to the payment of common dividends, we must first pay dividends to the holders of preferred stock based on the fixed dividend rate for each series.

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. Our board of directors reviews our common stock dividend policy from time to time. Among the factors the board of directors considers in determining our dividend policy are earnings, cash flows, capitalization ratios, regulation, competition and financial loan covenants. During 2008 our board of directors declared four quarterly dividends, each at $0.29 per share, reflecting an annual dividend of $1.16 per share. On February 25, 2009, our board of directors declared a quarterly dividend of $0.30 per share on our common stock payable to shareholders on April 1, 2009. The indicated annual dividend rate is $1.20 per share.

Our articles of incorporation restrict the payment of dividends or the making of other distributions on our common stock while any preferred shares remain outstanding unless we meet certain capitalization ratios and other conditions. We were not limited by any such restrictions during 2008. We provide further information on these restrictions in Note 17 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock." We do not expect these restrictions to have an impact on our ability to pay dividends on our common stock.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(In Thousands)				
Income Statement Data:					
Sales	$1,838,996	$1,726,834	$1,605,743	$1,583,278	$1,464,489
Income from continuing operations	178,140	168,354	165,309	134,868	100,080
Earnings available for common stock	177,170	167,384	164,339	134,640	177,900

	As of December 31,				
	2008	2007	2006	2005	2004
	(In Thousands)				
Balance Sheet Data:					
Total assets	$7,443,259	$6,395,430	$5,455,175	$5,210,069	$5,001,144
Long-term obligations and mandatorily redeemable preferred stock (a)	2,465,968	2,022,493	1,580,108	1,681,301	1,724,967

	Year Ended December 31,				
	2008	2007	2006	2005	2004
Common Stock Data:					
Basic earnings per share available for common stock from continuing operations	$ 1.70	$ 1.85	$ 1.88	$ 1.54	$ 1.19
Basic earnings per share available for common stock	$ 1.70	$ 1.85	$ 1.88	$ 1.55	$ 2.14
Dividends declared per share	$ 1.16	$ 1.08	$ 1.00	$ 0.92	$ 0.80
Book value per share	$ 20.18	$ 19.14	$ 17.61	$ 16.31	$ 16.13
Average equivalent common shares outstanding (in thousands) (b) (c) (d)	103,958	90,676	87,510	86,855	82,941

(a) Includes long-term debt and capital leases.
(b) In 2004, we issued and sold approximately 12.5 million shares of common stock realizing net proceeds of $245.1 million.
(c) In 2007, we issued and sold approximately 8.1 million shares of common stock realizing net proceeds of $195.4 million.
(d) In 2008, we 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

INTRODUCTION

We are the largest electric utility in Kansas. We produce, transmit and sell electricity at retail in Kansas and at wholesale in a multi-state region in the central United States under the regulation of the KCC and FERC.

In Management's Discussion and Analysis, we discuss our general financial condition, significant changes that occurred during 2008, and our operating results for the years ended December 31, 2008, 2007 and 2006. As you read Management's Discussion and Analysis, please refer to our consolidated financial statements and the accompanying notes, which contain our operating results.

SUMMARY OF SIGNIFICANT ITEMS

Overview

Several significant items have impacted or may impact us and our operations since January 1, 2008:

- Income from operations for the year ended December 31, 2008, decreased compared to the prior year due primarily to a 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 in the first and second quarters of 2008. See "—Decrease in Income from Operations" below for additional information;

- We reached a settlement with the IRS on issues principally related to the method used to capitalize overheads to electric plant for the years 1995 through 2002, which resulted in a 2008 net earnings benefit of approximately $39.4 million. See "—Recognition of Previously Unrecognized Tax Benefits" below for additional information. We also recognized $14.6 million in state tax incentives related to investment and jobs creation within the state of Kansas;

- We received regulatory approval to increase retail rates $130.0 million per year. The primary drivers for our rate increase were investments in natural gas generation facilities, wind generation facilities and other capital projects, costs attributable to the 2007 ice storm, higher operating costs and an update of our capital structure. For additional information, see Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation;"

- We made capital expenditures of $937.2 million during 2008. See "—Increased Capacity and Future Plans" and "—Liquidity and Capital Resources" below for additional information;

- We issued 12.3 million shares of common stock for net proceeds of $290.2 million through a Sales Agency Financing Agreement, a forward sale agreement and an underwriting agreement. We also issued an additional $450.0 million principal amount of first mortgage bonds as part of our efforts to raise the funds needed for our capital projects. We expect to continue to issue equity and debt securities as external funds are needed to complete planned capital investments;

- As a result of market conditions, we experienced a significant loss in the value of assets in our pension and nuclear decommission trusts. This will increase our pension expense in future periods and will require us to make additional contributions to these trusts;

- Global and U.S. economic conditions throughout 2008 have begun to impact certain of our industrial and commercial customers and may affect our residential business. Kansas companies are experiencing reduced production and have announced significant employee layoffs. Kansas is experiencing an increase in unemployment claims and the unemployment rate. We cannot determine when these conditions may reverse or whether and to what extent they may affect our results of operations.

Decrease in Income from Operations

Income from operations decreased $52.7 million or 16% compared to last year. This decrease is attributable primarily to a 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 $22.5 million due primarily 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. A notable trend is that more transactions are being completed through RTO-sponsored markets as opposed to negotiated transactions directly between individual counterparties. In addition, as measured by cooling degree days, the weather during 2008 was 20% cooler than last year. While increases in the cost of fuel and purchased power generally are recoverable in the RECA applicable to our retail sales, we sold power to a few large industrial customers under contracts to which the RECA did not apply. Margins on sales to customers under these contracts were approximately $9.9 million lower compared to last year. Effective July 1, 2008, an industrial customer who accounted for approximately 65% of sales under these contracts is now served under a new tariff that incorporates the RECA. The remainder of these contracts will expire by the end of 2009. Furthermore, there were additional planned outages at our base load plants in 2008 that were longer in duration than the prior year. The additional planned outages required us to use more expensive fuel and to incur additional purchased power expense. This resulted in reduced margins on power sold, notwithstanding higher prevailing market prices. Margins on market-based wholesale sales decreased $9.1 million or 13% compared to last year.

Recognition of Previously Unrecognized Tax Benefits

In December 2007, we reached a tentative settlement with the IRS Office of Appeals on issues principally related to the method used to capitalize overheads to electric plant for years 1995 through 2002. This settlement, which was approved by the Joint Committee on Taxation and accepted by the IRS in February 2008, resulted in a 2008 net earnings benefit of approximately $39.4 million, including interest, due to the recognition of previously unrecognized tax benefits. The recognition of these previously unrecognized tax benefits resulted in earnings of $0.38 per share for the year ended December 31, 2008.

Changes in Rates

We filed an application with the KCC in May 2008 to increase retail rates by $177.6 million per year. The primary drivers for this application were investments in natural gas generation facilities, wind generation facilities and other capital projects, costs attributable to the 2007 ice storm, higher operating costs and an update of our capital structure. On October 27, 2008, all parties to the proceeding filed an agreement with the KCC supporting a $130.0 million annual increase in our retail rates. On January 21, 2009, the KCC issued an order approving the settlement agreement and the new retail rates became effective on February 3, 2009.

On July 1, 2008, we implemented an initial retail TDC on a revenue neutral basis to capture transmission costs ultimately approved in our 2005 general rate case. On September 18, 2008, the KCC granted our request to adjust the TDC to include more recent transmission costs approved by FERC and attributable to the retail portion of our transmission service. This served to increase our estimated annual retail revenues by $6.1 million.

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

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.

Increased Capacity and Future Plans

In May 2008, we and Electric Transmission America, LLC formed Prairie Wind Transmission, a joint venture company of which we own 50%. Prairie Wind Transmission is proposing to construct approximately 230 miles of 765 kV transmission facilities in Kansas extending west from near Wichita to near Dodge City and then south-southwest to the Kansas-Oklahoma border. On December 2, 2008, FERC approved a number of key rate components related to these transmission facilities and set aside for hearing the establishment of a formula rate and associated protocols. Should Prairie Wind Transmission receive the necessary regulatory approvals from the KCC and FERC, the facilities are expected to be in service by the end of 2013, contingent on a number of factors including the availability and cost of capital, not all of which are under our control. We will incur significant future capital expenditures related to this joint venture if Prairie Wind Transmission receives regulatory approval to build the transmission facilities.

We have been working with third parties to develop approximately 300 MW of wind generation facilities at three different sites in Kansas. Under the terms of the agreements, we will own approximately half of the wind generation facilities at an expected cost of approximately $282.0 million and will purchase energy produced by the wind generation facilities under twenty year supply contracts for the other half. One of the facilities from which we purchase energy began producing energy in December 2008 and we expect the other two to begin producing energy in early 2009.

We are constructing a 345 kV transmission line from our Gordon Evans Energy Center northwest of Wichita, Kansas, to a new substation near Hutchinson, Kansas, then on to our Summit substation near Salina, Kansas, a distance totaling approximately 100 miles. We completed construction of the first segment in December 2008 and expect the second segment to be completed by June 2010. We expect the total investment in the line and substations to be approximately $200.0 million.

In addition to the transmission line described above, we also plan to construct a new 345 kV line from a substation near Wichita to the Kansas-Oklahoma border, where we will interconnect with new facilities being built by an Oklahoma utility. The preliminary estimate of the investment in the line is approximately $90.0 million, which is subject to change pending final engineering design, labor and materials, among other factors. We expect to begin construction in 2010.

In 2008, we completed the first phase of our Emporia Energy Center, a new natural gas-fired peaking power plant consisting of seven combustion turbines located near Emporia in Lyon County, Kansas, comprising approximately 350 MW of capacity. We expect to complete construction of the second phase, consisting of two generating units that will add an additional approximately 320 MW of generating capacity, early in 2009 for a total investment of about $318.0 million.

Economic Conditions

In 2008, global economic growth slowed, liquidity was reduced in global capital markets and the U.S. entered a recession. The downturn became more intense in the fourth quarter of 2008. Growth in industrial production decreased from 2007 levels, and business and consumer confidence declined throughout 2008. The rate of inflation increased in the first half of 2008 with rising food and energy prices, but declined in the latter part of the year.

The state of the economy may adversely affect a number of aspects of our business. While the full impact of these events is currently unknown, several developments can be highlighted.

Certain of our industrial and commercial customers have informed us that they are experiencing a decrease in orders and have reduced production and work schedules. Further, several of our large industrial customers have recently announced significant employee layoffs.

Our residential business may be affected by general economic conditions. The Kansas unemployment rate increased from 4.2% in December 2007 to 5.2% in December 2008. Initial unemployment claims in Kansas jumped to approximately 37,000 claims in December 2008 from approximately 18,000 claims in December 2007.

We cannot predict whether these developments will continue or when the economy generally may stabilize. We also cannot state whether or to what extent any such developments will impact our results of operations, which are affected by economic conditions as well as by a broad number of other factors, including without limitation those factors summarized in this Form 10-K in the sections entitled "Forward Looking Statements" and "Item 1A. Risk Factors."

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 for our regulated utility operations that recognize the economic effects of rate regulation in accordance with SFAS No. 71. 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 utility rates. 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. To the extent recovery of costs is no longer deemed to be probable, we would record a charge against income in the amount of the related regulatory assets.

Pension and Post-retirement Benefit Plans Actuarial Assumptions

We and Wolf Creek calculate our pension benefit and post-retirement medical benefit obligations and related costs using actuarial concepts within the guidance provided by SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 106, "Employers' Accounting for Post-retirement Benefits Other Than Pensions" and SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans – An Amendment of FASB Statements No. 87, 88, 106, and 132(R)."

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. A change in any of these assumptions could have a significant impact on future costs, which may be reflected as an increase or decrease in net income in the current and future periods, or on the amount of related liabilities reflected on our consolidated balance sheets or may also require cash contributions.

The following table shows the annual 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	Annual Change in Projected Benefit Obligation	Annual Change in Pension Liability/Asset	Annual Change in Projected Pension Expense
			(In Thousands)	
Discount rate	0.5% decrease	$ 52,188	$ 52,188	$ 5,321
	0.5% increase	(48,682)	(48,682)	(5,170)
Salary scale	0.5% decrease	(13,199)	(13,199)	(2,609)
	0.5% increase	13,462	13,462	2,686
Rate of return on plan assets	0.5% decrease	—	—	2,506
	0.5% increase	—	—	(2,506)

We recorded pension costs of approximately $22.7 million in 2008 and $21.4 million in both 2007 and 2006. These amounts reflect the pension costs of Westar Energy and our 47% responsibility for the pension costs of Wolf Creek. Pension costs for 2009 are expected to be approximately $38.1 million. The increase in pension costs from 2008 to that expected in 2009 is due primarily to significantly lower than expected investment returns in 2008. The investment gains or losses resulting from the difference between the expected return on assets and actual returns earned are deferred in the year the difference arises. The gain or loss recognition occurs by using a four-year moving average value of pension assets to measure the expected return on assets in the pension cost, and by amortizing deferred investment gains or losses over the average remaining service life of employees. 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.

The following table shows the annual 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	Annual Change in Projected Benefit Obligation	Annual Change in Post-retirement Liability/Asset	Annual Change in Projected Post-retirement Expense
			(In Thousands)	
Discount rate	0.5% decrease	$ 8,061	$ 8,061	$ 513
	0.5% increase	(7,626)	(7,626)	(520)
Rate of return on plan assets	0.5% decrease	—	—	282
	0.5% increase	—	—	(282)

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 the electric usage from the last meter read and record the corresponding unbilled revenue.

The accuracy of our unbilled revenue estimate is affected by factors including fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $47.7 million as of December 31, 2008, and $43.7 million as of December 31, 2007.

We account for energy marketing derivative contracts under the mark-to-market 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 a fuel supply contract and a capacity sale contract, which we record as regulatory liabilities, we include the net mark-to-market change in sales 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 is 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 statements.

The tables below show the fair value of energy marketing contracts that were outstanding as of December 31, 2008, their sources and maturity periods.

	Fair Value of Contracts (In Thousands)
Net fair value of contracts outstanding as of December 31, 2007 (a)	$ 41,502
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	(14,879)
Changes in fair value of contracts outstanding at the beginning and end of the period	16,058
Fair value of new contracts entered into during the period	7,683
Fair value of contracts outstanding as of December 31, 2008 (a)	$ 50,364

(a) Approximately $36.3 million at December 31, 2008, and $34.0 million at December 31, 2007, of the fair value of energy marketing contracts is recognized as a regulatory liability.

The sources of the fair values of the financial instruments related to these contracts as of December 31, 2008, 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)	$ 6	$ —	$ 6	$ —	$ —
Prices provided by other external sources (swaps and forwards)	42,239	18,977	16,577	4,512	2,173
Prices based on option pricing models (options and other) (a)	8,119	8,048	950	(670)	(209)
Total fair value of contracts outstanding	$ 50,364	$ 27,025	$ 17,533	$ 3,842	$ 1,964

(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 as required by SFAS No. 109, “Accounting for Income Taxes.” Under the asset and liability 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 record deferred tax assets for capital losses, operating losses and tax credit carryforwards. However, when we believe we do not, or will not have sufficient future capital gain income or taxable income to realize the benefit of the capital loss, operating loss or tax credit carryforwards, we reduce the deferred tax assets by a valuation allowance. We recognize a valuation allowance if we determine, based on available evidence that it is unlikely that we will realize some portion or all of the deferred tax asset. We report the effect of a change in the valuation allowance in the current period tax expense.

We account for uncertainty in income taxes in accordance with FIN 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109." The application of income tax law is complex. Laws and regulations in this area are voluminous and are often ambiguous. Accordingly, we must make subjective assumptions and judgments regarding income tax exposures. Interpretations of and guidance surrounding income tax laws and regulations change over time. As a result, changes in our subjective assumptions and judgments can materially affect amounts we recognize in the consolidated financial statements. See Note 10 of the Notes to Consolidated Financial Statements, "Taxes," for additional detail of our uncertainty in income taxes.

Asset Retirement Obligations

We calculate our asset retirement obligations and related costs using the guidance provided by SFAS No. 143, "Accounting for Asset Retirement Obligations" and FIN 47, "Accounting for Conditional Asset Retirement Obligations."

We estimate our asset retirement obligations based on the fair value of the asset retirement obligation we incurred at the time the related long-lived asset was either acquired, placed in service or when regulations establishing the obligation become effective.

In determining our asset retirement obligations, we make assumptions regarding probable disposal costs. A change in these assumptions could have a significant impact on our asset retirement obligations reflected on our consolidated balance sheets. See Note 14 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations," for additional detail of our asset retirement obligations.

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 15 of the Notes to Consolidated Financial Statements, "Legal Proceedings," for more detailed information.

OPERATING RESULTS

We evaluate operating results based on earnings per share. We have various classifications of sales, 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.

Tariff-based wholesale: Sales of energy to electric cooperatives, municipalities and other electric utilities, the rates for which are generally based on cost as prescribed by FERC tariffs. This category also includes changes in valuations of contracts for the sale of such energy that have yet to settle.

Market-based wholesale: Includes: (i) sales of energy to wholesale customers, the rates for which are generally based on prevailing market prices as allowed by FERC approved market-based tariffs, or where not permitted, pricing is based on incremental cost plus a permitted margin and (ii) changes in valuations for contracts for the sale of such contracts that have yet to settle.

Energy marketing: Includes: (i) transactions based on market prices with volumes not related to the production of our generating assets or the demand of our retail customers; (ii) financially settled products and physical transactions sourced outside our control area; (iii) fees we earn for marketing services that we provide for third parties; and (iv) changes in valuations for contracts related to such transactions that have yet to settle.

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

Other: Miscellaneous electric revenues including ancillary service revenues and rent from electric property leased to others.

Regulated electric utility sales are significantly impacted by such things as rate regulation, customer conservation efforts, wholesale demand, the economy of our service area and competitive forces. Changing weather affects the amount of electricity our customers use. Hot summer temperatures and cold winter temperatures prompt more demand, especially among our residential customers. Mild weather serves to reduce customer demand. Our wholesale sales are impacted by, among other factors, demand, cost and availability of fuel and purchased power, price volatility, available generation capacity and transmission availability.

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. Changes in results of operations are as follows.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
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 Sales	1,287,712	1,185,964	101,748	8.6
Tariff-based wholesale	239,693	218,647	21,046	9.6
Market-based wholesale	174,116	161,796	12,320	7.6
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 Sales	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 (loss) 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	$ 1.70	$ 1.85	$ (0.15)	(8.1)

(a) **Transmission:** Includes 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.

The following table reflects changes in electric sales volumes, as measured by thousands of MWh of electricity. No sales volumes are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to the amount of electricity we generate at our generating plants.

	Year Ended December 31,			
	2008	2007	Change	% Change
	(Thousands of MWh)			
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)
Tariff-based wholesale	6,176	6,360	(184)	(2.9)
Market-based wholesale	3,208	3,666	(458)	(12.5)
Total	29,098	30,150	(1,052)	(3.5)

Notwithstanding a 2% decrease in MWh sales volumes, retail sales were $101.7 million higher for the year ended December 31, 2008, due principally to our prices including higher fuel and purchased power costs. Residential, commercial and industrial sales increased a combined $89.7 million primarily because fuel costs reflected in the RECA were $114.3 million higher compared to last year. Partially offsetting the higher revenues attributable to the RECA was the effect of cooler weather. As measured by cooling degree days, the weather during 2008 was 20% cooler than during 2007. The $12.0 million change in other retail sales is due primarily to decreases in refund obligations compared to last year.

Tariff-based wholesale sales were $21.0 million higher than last year attributable principally to a 13% higher average price per MWh for these sales compared to last year. The higher average price was the result of including higher fuel costs in the prices we charge. Partially offsetting the higher average price per MWh was a 3% decrease in sales volumes due primarily to the expiration of wholesale contracts.

Market-based wholesale sales increased $12.3 million compared to last year due principally to a 12% higher average price for these sales compared to last year. Partially offsetting the higher average price was a 12% decrease in sales volumes attributable primarily to our having less production available due to extended outages at some of our lower cost base load plants during 2008.

Energy marketing decreased $22.5 million compared to the previous year due to several factors. Among them were: the need to focus resources toward serving our retail customers during our extended outages, changes in the relationships of prices among energy products historically traded and the continuing maturation of the energy markets in which we participate reducing margin opportunities. A notable trend is that more transactions are being completed through RTO-sponsored markets as opposed to negotiated transactions directly between counterparties. While this trend is expected to continue, we are unable to determine how all of the aforementioned factors may affect energy marketing in the future. Contributing to the decrease was the recognition of a $3.2 million customer refund obligation and the recognition of 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.

Fuel and purchased power expense increased $149.9 million compared to last year. The change in fuel and purchased power expense resulted from a number of factors, including: the volumes of power we produced and purchased, prevailing market prices and contract provisions that allow for price changes. Fuel used for generation increased $73.3 million, or 15%, stemming primarily from outages at our lower cost, base load plants that caused us to rely more heavily on our plants that require more expensive fuels. When compared to the year ended December 31, 2007, we used 5% less fuel by volume this year, in part because of greater purchases of power from others. Because some of our plants that use the least expensive fuels (i.e. nuclear and coal) were not producing at times due to outages, we had the choice of either producing the needed volumes at plants that are more expensive to operate or acquiring those volumes from others. Generally, purchasing power from others was the more economical alternative, and as a result, our purchased power expense increased $31.4 million, reflecting a 34% increase in such volumes. For almost all retail customers, the cost of fuel and purchased power we incur that is in excess of costs recovered in rates is deferred as a regulatory asset until the costs are recovered. For the year ended December 31, 2008, we recovered $13.4 million for fuel expense previously deferred compared to deferring $26.7 million of fuel expense during the year ended December 31, 2007.

Depreciation and amortization expense increased $10.8 million compared to last year due to depreciation expense associated with a higher plant balance.

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.

Investment earnings decreased $16.5 million compared to last year 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 for the prior year.

Other income increased $22.9 million compared to last year due primarily to our having recorded $18.3 million of equity allowance for funds used during construction (AFUDC) this year compared to $4.3 million of equity AFUDC recorded last year. 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 corporate-owned life insurance (COLI) benefit this year compared to $0.7 million of COLI benefit recorded last year.

Interest expense increased $2.6 million compared to last year 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.

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

2007 Compared to 2006

Below we discuss our operating results for the year ended December 31, 2007, compared to the results for the year ended December 31, 2006. Changes in results of operations are as follows.

	Year Ended December 31,			
	2007	2006	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 491,163	$ 486,107	$ 5,056	1.0
Commercial	448,368	438,342	10,026	2.3
Industrial	264,566	266,922	(2,356)	(0.9)
Other retail	(18,133)	(32,098)	13,965	43.5
Total Retail Sales	1,185,964	1,159,273	26,691	2.3
Tariff-based wholesale	218,647	195,428	23,219	11.9
Market-based wholesale	161,796	105,768	56,028	53.0
Energy marketing	36,978	35,562	1,416	4.0
Transmission (a)	97,717	83,764	13,953	16.7
Other	25,732	25,948	(216)	(0.8)
Total Sales	1,726,834	1,605,743	121,091	7.5
OPERATING EXPENSES:				
Fuel and purchased power	544,421	483,959	60,462	12.5
Operating and maintenance	473,525	463,785	9,740	2.1
Depreciation and amortization	192,910	180,228	12,682	7.0
Selling, general and administrative	178,587	171,001	7,586	4.4
Total Operating Expenses	1,389,443	1,298,973	90,470	7.0
INCOME FROM OPERATIONS	337,391	306,770	30,621	10.0
OTHER INCOME (EXPENSE):				
Investment earnings	6,031	9,212	(3,181)	(34.5)
Other income	6,726	18,000	(11,274)	(62.6)
Other expense	(14,072)	(13,711)	(361)	(2.6)
Total Other (Expense) Income	(1,315)	13,501	(14,816)	(109.7)
Interest expense	103,883	98,650	5,233	5.3
INCOME BEFORE INCOME TAXES	232,193	221,621	10,572	4.8
Income tax expense	63,839	56,312	7,527	13.4
NET INCOME	168,354	165,309	3,045	1.8
Preferred dividends	970	970	—	—
EARNINGS AVAILABLE FOR COMMON STOCK	$ 167,384	$ 164,339	$ 3,045	1.9
BASIC EARNINGS PER SHARE	$ 1.85	$ 1.88	$ (0.03)	(1.6)

(a) **Transmission:** Includes an SPP network transmission tariff. In 2007, our SPP network transmission costs were $82.0 million. This amount, less $9.2 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2006, our SPP network transmission costs were $76.0 million with an administration cost of $10.1 million retained by the SPP.

The following table reflects changes in electric sales volumes, as measured by thousands of MWh of electricity. No sales volumes are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to the amount of electricity we generate at our generating plants.

	Year Ended December 31,			
	2007	2006	Change	% Change
	(Thousands of MWh)			
Residential	6,677	6,456	221	3.4
Commercial	7,537	7,185	352	4.9
Industrial	5,819	5,824	(5)	(0.1)
Other retail	91	93	(2)	(2.2)
Total Retail	20,124	19,558	566	2.9
Tariff-based wholesale	6,360	5,505	855	15.5
Market-based wholesale	3,666	1,913	1,753	91.6
Total	30,150	26,976	3,174	11.8

Retail sales were $26.7 million higher for the year ended December 31, 2007, due principally to increases in other retail, commercial and residential sales. Other retail sales increased $14.0 million due primarily to decreases in refund obligations. Commercial and residential sales increased a combined $15.1 million due primarily to cooler weather during the winter months and customer growth in our service territory. When measured by heating degree days, the weather during 2007 was 16% cooler than during 2006.

Tariff-based wholesale sales were $23.2 million higher in 2007 than in 2006 due principally to increased sales volumes that were primarily the result of additional sales from the long-term sale agreement entered into in 2007 with Mid-Kansas Electric Company, LLC. The average price per MWh for these sales, however, was about 3% lower in 2007 than in 2006.

Market-based wholesale sales were $56.0 million higher in 2007 than in 2006 due principally to increased sales volumes that were primarily the result of coal conservation efforts and a scheduled refueling outage at Wolf Creek, both of which occurred in 2006 and did not recur in 2007. The average price per MWh for these sales, however, was about 13% lower in 2007 than in 2006.

Fuel and purchased power expense increased $60.5 million in 2007 compared to 2006. The change in fuel and purchased power expense resulted from a number of factors, including: the volumes of power we produced and purchased, prevailing market prices and contract provisions that allow for price changes. We used 12% more fuel in our generating plants in 2007, due primarily to our not having had to conserve coal this year as we did in 2006. This resulted in $53.6 million higher fuel expense compared with 2006. Purchased power expense increased $6.8 million over 2006 due primarily to higher prices, but were largely offset by a 4% reduction in purchased volumes. In 2007 through the RECA, we deferred for future recovery $26.7 million of fuel and purchased power costs as a regulatory asset compared with $6.9 million in 2006.

Operating and maintenance expense increased $9.7 million in 2007 compared to 2006. This was due primarily to higher maintenance costs of $8.7 million for our power plants, electrical distribution system and transmission system and a $6.0 million increase in SPP network transmission costs that are in large part recovered through higher transmission revenues.

Depreciation and amortization expense increased $12.7 million in 2007 compared to 2006. This was due principally to depreciation expense associated with a higher plant balance including the capital lease associated with the purchase of Aquila Inc.'s (Aquila) 8% leasehold interest in Jeffrey Energy Center.

Selling, general and administrative expense increased $7.6 million due primarily to a $6.2 million increase in employee benefit costs and a $6.0 million increase in labor costs. These increases were partially offset by reduced legal fees associated with matters having to deal with former management.

Other income decreased $11.3 million in 2007 compared to 2006 due primarily to our having recorded $0.7 million in proceeds from COLI in 2007 compared to $16.4 million in COLI proceeds recorded in 2006. Partially offsetting this decrease was the recording of $4.3 million of equity AFUDC for 2007, which compares to no equity AFUDC recorded for 2006.

Income tax expense increased $7.5 million in 2007 compared to 2006 due primarily to decreases in the utilization of previously unrecognized capital loss carryforwards to offset realized capital gains and decreases in non-taxable income from COLI. The increase was partially offset by increased tax benefits from the utilization of a net operating loss that had not previously been applied against income for other carryback or carryover years.

FINANCIAL CONDITION

A number of factors affected amounts recorded on our balance sheet as of December 31, 2008, compared to December 31, 2007.

Given unprecedented uncertainty in capital markets and concerns about how well the banking industry may function amidst the turmoil, we decided to increase cash holdings to allow for additional flexibility, resulting in an increase in cash and cash equivalents of $17.2 million over last year.

Inventories and supplies increased $11.8 million due primarily to a $17.1 million increase related to new facilities and large construction projects. Upward adjustments to some of our coal contracts and increased freight costs together contributed to a $6.5 million increase in coal inventory. Increases were partially offset by the sale of $13.0 million of oil.

The fair market value of energy marketing contracts increased $8.9 million to $50.4 million at December 31, 2008. This was due primarily to favorable changes in market values of contracts outstanding throughout 2008, in addition to contracts entered into in 2008.

Tax receivable decreased $34.6 million due primarily to receipt of a tax refund and the settlement of the IRS audit of tax years 1995 through 2002.

Regulatory assets, net of regulatory liabilities, increased $295.4 million to $829.2 million at December 31, 2008, from $533.8 million at December 31, 2007. Total regulatory assets increased $276.8 million due primarily to the fair market value of employee benefit plan assets decreasing. We recognize as a regulatory asset or regulatory liability the difference between the fair value of pension and post-retirement benefit plan assets and the liabilities for our pension and post-retirement benefit plans. The significant decline in the value of pension assets in 2008 resulted in a $237.5 million increase in regulatory assets. Further increasing regulatory assets was $39.8 million of additional net deferred future income taxes. Total regulatory liabilities decreased $18.6 million due primarily to a $36.7 million decrease in the fair value of the nuclear decommissioning trust largely offset by a $24.9 million increase in removal costs for amounts collected and not yet spent to remove retired assets.

Other long-term assets decreased $7.5 million due primarily to a $10.9 million decrease in the fair value of assets held in a trust used to fund retirement benefits.

Other current liabilities increased $14.3 million due primarily to declaring dividends on a greater number of shares in 2008.

Long-term debt, net of current maturities, increased $302.8 million due principally to the issuance of $450.0 million of first mortgage bonds as discussed in detail in Note 9 of the Notes to Consolidated Financial Statements, “Long-Term Debt.” The increase was partially offset by the reclassification of $145.1 million of long-term debt due August 1, 2009, to current maturities.

Other long-term liabilities decreased $62.3 million due primarily to a $39.4 million decrease in uncertain tax liabilities and related accrued interest. See Note 10 of the Notes to Consolidated Financial Statements, “Taxes.”

Common stock and paid-in capital increased $305.5 million due principally to the issuance of common stock as discussed in Note 17 of the Notes to the Consolidated Financial Statements, “Common and Preferred Stock.”

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 others, fuel and purchased power, dividends, interest payments, income taxes and pension contributions, primarily using 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 the proceeds from the issuance of securities to repay borrowings under the revolving credit facility, with those borrowed amounts principally related to our 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 with a significant increase in cash requirements for our capital investments. For additional information on our future cash requirements, see “—Future Cash Requirements” below.

In the latter part of 2008, capital markets experienced unprecedented volatility and dramatic declines in asset valuations. As a result, capital is more costly and more difficult to obtain. In light of the current volatility and the unpredictability of how long these capital market conditions will persist, we have reduced or delayed construction spending and other capital outlays in order to manage liquidity. Additionally, this volatility, accompanied by reduced asset values, will require us to make additional contributions to the Westar Energy pension trust and to increase our funding of the Wolf Creek pension trust. See “—Pension Obligation” below for additional information. We do not expect the previously mentioned economic conditions to impact our ability to pay dividends. Uncertainties affecting our ability to meet cash requirements include, among others: factors affecting sales described in “—Operating Results” above, economic conditions, regulatory actions, compliance with environmental regulations and conditions in the capital markets.

Capital Resources

As of December 31, 2008, we had $22.9 million in unrestricted cash and cash equivalents. On January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to 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 15, 2008, FERC granted our request and on February 22, 2008, a syndicate of banks in the credit facility increased their commitments to $750.0 million in the aggregate. Effective February 22, 2008, $730.0 million of the commitments of the lenders under the revolving credit facility terminate on March 17, 2012. The remaining $20.0 million of the commitments terminate on March 17, 2011.

Lehman Brothers Commercial Paper, Inc. (Lehman Brothers) is the participating lender with respect to a $20.0 million commitment terminating 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. As of February 18, 2009, $230.2 million had been borrowed and an additional $21.1 million of letters of credit had been issued under the revolving credit facility.

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, 2008, our ratio was 54%. 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.

The Westar Energy 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. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. As of December 31, 2008, based on an assumed interest rate of 7.50%, approximately $138.0 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.

The KGE 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. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. As of December 31, 2008, based on an assumed interest rate of 7.50%, approximately $415.0 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, we entered into an underwriting agreement relating to the offer and sale of 6.0 million shares of the company's common stock. On June 4, 2008, we 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, we entered into a forward sale agreement with a bank, as forward purchaser, relating to 8.2 million shares of our common stock. The forward sale agreement provides for the sale of our 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 our 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, we delivered 3.1 million newly issued shares of our 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, we delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. On June 30, 2008, we completed the forward sale agreement by delivering 3.0 million shares and receiving proceeds of $73.0 million.

On August 24, 2007, we entered into a Sales Agency Financing Agreement with a bank. Under the terms of the agreement, we may offer and sell shares of our 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. We will pay the bank a commission equal to 1% of the sales price of all shares sold under the agreement. During 2007 we 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 we 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.

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

We used the proceeds from the issuance of common stock to repay borrowings under Westar Energy's 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 $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 this year compared to last 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 this year at our base load plants; our having paid more for fuel and purchased power this year compared to last year; and during 2008, we paid $15.7 million more for our share of Wolf Creek's refueling outage.

Cash flows from operating activities decreased $9.2 million to $246.8 million in 2007, from $256.0 million in 2006. During 2007, as compared to 2006, we paid approximately $48.3 million more for natural gas used in our power plants, $29.8 million more for coal inventory and $29.4 million more in customer refunds. Offsetting these amounts were a $10.1 million reduction in La Cygne unit 2 lease payments, $9.0 million less in voluntary contributions to our pension trust and cash realized from higher gross margins. During 2006, we also used $65.0 million related to the termination of our accounts receivable sales program.

Cash Flows used in Investing Activities

In general, cash used for investing purposes relates to the growth and improvement of our electric utility business. The utility business is capital intensive and requires significant investment in plant on an annual basis. We spent $937.2 million in 2008, $748.2 million in 2007 and $344.9 million in 2006 on net additions to utility property, plant and equipment. The increase from 2006 to 2008 is due primarily to environmental projects, wind generation projects, transmission projects and the construction of Emporia Energy Center.

Cash Flows used in Financing Activities

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.

In 2006, we received net cash flows from financing activities of $12.8 million. An increase in short-term debt was the principal source of cash flows from financing activities. Cash from financing activities was used to retire long-term debt and to pay dividends.

Future Cash Requirements

Our business requires significant capital investments. Through 2011, we expect we will need cash primarily for utility construction programs designed to improve and expand facilities providing electric service, which include but are not limited to expenditures for peaking capacity needs, new transmission lines and for compliance with environmental regulations. 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. In addition, the current focus on the effect of air emissions on the global environment 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 rate increases, there is no guarantee that we will be able to do so. In addition, we may be subject to significant fines and penalties in connection with the NSR Investigation and the related DOJ lawsuit or other matters, and such fines and penalties may not be recovered through rate increases.

Capital expenditures for 2008 and anticipated capital expenditures including costs of removal for 2009 through 2011 are shown in the following table.

	Actual 2008	2009	2010	2011
		(In Thousands)		
Generation:				
Replacements and other	$110,942	$113,700	$113,500	$117,300
Additional capacity	138,893	39,200	12,300	10,200
Wind generation	130,404	2,200	200,000	—
Environmental	257,218	83,900	235,600	407,800
Nuclear fuel	17,668	23,000	30,100	24,400
Transmission (a)	149,988	132,500	222,800	172,700
Distribution:				
Replacements and other	45,805	40,500	64,100	88,200
New customers	54,360	58,600	61,500	64,300
Other	31,964	7,700	22,400	22,100
Total capital expenditures	$937,242	$501,300	$962,300	$907,000

(a) Includes $9,000 in 2010 and $26,100 in 2011 for expenditures related to Prairie Wind Transmission.

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 expenditures that may be incurred as a result of the NSR Investigation and the related DOJ lawsuit or for potentially new environmental requirements relating to mercury and CO_2 emissions.

Maturities of long-term debt as of December 31, 2008, are as follows.

Year	Principal Amount (In Thousands)
2009	$ 146,366
2010	1,345
2011	61
2012	—
Thereafter	2,196,118
Total long-term debt maturities	$ 2,343,890

Debt Financings

As of December 31, 2008, we had $171.9 million of variable rate, tax-exempt bonds. Interest rates payable under these bonds have historically been set by auctions, which occur every 35 days. During 2008, auctions for these bonds failed, resulting in alternative index-based interest rates for these bonds of between 1% and 14%. On July 31, 2008, the KCC approved our request to remarket or refund all or part of these auction rate bonds, at our discretion. On August 26, 2008, we completed the refunding of $50.0 million of auction rate bonds at a fixed interest rate of 5.60% and a maturity date of June 1, 2031. On October 10, 2008, we completed the refunding of an additional $50.0 million of auction rate bonds at a fixed interest rate of 6.00% and a maturity date of June 1, 2031. We continue to monitor the credit markets and evaluate our options with respect to the remaining auction rate bonds.

On November 25, 2008, Westar Energy issued $300.0 million principal amount of first mortgage bonds at a discount to yield 8.750%, but bearing 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 December 2007, we entered into a $1.8 million equipment financing loan agreement with a term of 36 months to finance the cost of certain computer equipment purchased in 2007. In January 2008, we increased the size of this loan by $2.1 million to $3.9 million for equipment purchases made in 2008. As of December 31, 2008, the balance of this loan was $2.7 million.

On October 15, 2007, KGE issued $175.0 million principal amount of 6.53% first mortgage bonds maturing in 2037 in a private placement to an institutional investor.

On May 16, 2007, Westar Energy sold $150.0 million aggregate principal amount of 6.10% Westar Energy first mortgage bonds maturing in 2047.

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, 2008.

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.

S&P upgraded its credit rating for Westar Energy’s unsecured debt securities in November 2008 and upgraded its credit rating for Westar Energy’s first mortgage bonds/senior secured debt securities in September 2007. 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 to stable.

As of February 18, 2009, 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
Moody’s	Baa2	Baa2	Baa3
S&P	BBB	BBB	BBB-
Fitch	BBB+	BBB+	BBB

In general, less favorable credit ratings make borrowing more difficult and costly. Under our 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.

Capital Structure

As of December 31, 2008 and 2007, our capital structure excluding short-term debt was as follows:

	2008	2007
Common equity	48%	49%
Preferred stock	<1%	1%
Long-term debt	51%	50%

OFF-BALANCE SHEET ARRANGEMENTS

Forward Equity Transaction

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

As of December 31, 2008, 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 18 of the Notes to Consolidated Financial Statements, “Leases.”

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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, 2008.

Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2008.

	Total	2009	2010 - 2011	2012 - 2013	Thereafter
			(In Thousands)		
Long-term debt (a)	$2,343,890	$146,366	$ 1,406	$ —	$2,196,118
Interest on long-term debt (b)	2,454,051	138,763	256,852	256,852	1,801,584
Adjusted long-term debt	4,797,941	285,129	258,258	256,852	3,997,702
Pension and post-retirement benefit expected contributions (c)	76,000	76,000	—	—	—
Capital leases (d)	188,137	17,443	31,897	19,558	119,239
Operating leases (e)	524,257	49,602	93,669	93,287	287,699
Fossil fuel (f)	1,683,980	297,565	514,021	422,329	450,065
Nuclear fuel (g)	381,269	21,268	56,161	57,909	245,931
Unconditional purchase obligations	270,475	174,736	86,536	9,203	—
Unrecognized income tax benefits including interest (h)	2,699	2,699	—	—	—
Total contractual obligations, including adjusted long-term debt	$7,924,758	$924,442	$ 1,040,542	$ 859,138	$5,100,636

(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, 2008.
(c) Pension and post-retirement benefit expected contributions represent the minimum funding requirements under the Employee Retirement Income Securities Act (ERISA) as amended by the Pension Protection Act (PPA), plus additional amounts as deemed fiscally appropriate. These 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 pensions.
(d) Includes principal and interest on capital leases, including the 8% leasehold interest in Jeffrey Energy Center that was purchased in 2007.
(e) Includes the La Cygne unit 2 lease, office space, operating facilities, office equipment, operating equipment, rail car leases and 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 $40.1 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 recognized pursuant to FIN 48 as of December 31, 2008.

Commercial Commitments

Our commercial commitments existing as of December 31, 2008, consist of outstanding letters of credit that expire in 2009, some of which automatically renew annually. The letters of credit are comprised of $4.5 million related to our energy marketing and trading activities, $9.9 million related to worker's compensation and $4.4 million related to other operating activities for a total outstanding balance of $18.8 million.

OTHER INFORMATION

Stock Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123R using the modified prospective transition method. Since 2002, we have used restricted share units (RSU) exclusively for our stock-based compensation awards. Given the characteristics of our stock-based compensation awards, the adoption of SFAS No. 123R did not have a material impact on our consolidated statements of income.

Total unrecognized compensation cost related to RSU awards was $5.8 million as of December 31, 2008. We expect to recognize these costs over a remaining weighted-average period of 1.8 years. Upon adoption of SFAS No. 123R, we were required to charge $10.3 million of unearned stock compensation against additional paid-in capital. There were no modifications of awards during the years ended December 31, 2008, 2007 or 2006.

Pension Obligation

The PPA changed the funding requirements for defined benefit pension plans beginning in 2008. Our pension costs and funding requirements are projected to increase as a result of the overall distressed global financial conditions and the decline in the equity and debt markets. We made voluntary contributions to our pension trust of $15.0 million in 2008 and $11.8 million in 2007. We expect to contribute approximately $51.9 million to our pension trust in 2009, of which $12.9 million is required and $39.0 million is voluntary. In 2008 and 2007, we also funded $5.5 million and $5.3 million, respectively, of Wolf Creek's pension trust. In 2009, we are required to fund $4.4 million of Wolf Creek's pension trust and we expect to also voluntarily fund $7.4 million. Future contributions will be based on the minimum funding required by law, plus additional amounts as determined fiscally appropriate for the company and the plans' funded positions. 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.

Customer Refunds and Rebates

We refunded to customers $39.4 million in 2007 related to the remand of the December 28, 2005, KCC Order (2005 KCC Order). We also made rebates to customers of $10.0 million during the year ended December 31, 2006, in accordance with a July 25, 2003, KCC Order.

Impact of Regulatory Accounting

We currently apply accounting standards that recognize the economic effects of rate regulation and record regulatory assets and liabilities related to our electric utility operations. If we determine that we no longer meet the criteria of SFAS No. 71, we may have a material non-cash charge to earnings.

As of December 31, 2008, we had recorded regulatory assets currently subject to recovery in future rates of approximately $952.3 million and regulatory liabilities of $123.1 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.

Asset Retirement Obligations

Legal Liability

In accordance with SFAS No. 143 and FIN 47, 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 an asset retirement obligation is capitalized and depreciated over the remaining life of the asset.

We initially recorded asset retirement obligations 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.

As of December 31, 2008 and 2007, we have recorded asset retirement obligations of $95.1 million and $88.7 million, respectively. For additional information on our legal asset retirement obligations, see Note 14 of the Notes to Consolidated Financial Statements, “Asset Retirement Obligations.”

Non-Legal Liability – Cost of Removal

We recover in rates the costs to dispose of utility plant assets that do not represent legal retirement obligations. As of December 31, 2008 and 2007, we had $50.1 million and $25.2 million, respectively, in amounts collected, but unspent, for removal costs classified as a regulatory liability. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in rates compared to removal costs incurred.

New Accounting Pronouncements

FSP No. EITF 03-6-1 – Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities

In June 2008, FASB released Staff Position (FSP) No. Emerging Issues Task Force (EITF), 03-6-1, “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.” FSP No. EITF 03-6-1 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 earnings per share pursuant to the two-class method. FSP No. EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. We do not expect the adoption of this guidance to have a material impact on our earnings per share.

SFAS No. 161 – Disclosures about Derivative Instruments and Hedging Activities

In March 2008, FASB released SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities – An Amendment of FASB Statement No. 133”, which requires expanded disclosure intended to help investors better understand how derivative instruments and hedging activities affect an entity’s financial position, financial performance and cash flows. SFAS No. 161 amends and expands our disclosure requirements related to SFAS No. 133, “Accounting for 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. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008.

SFAS No. 159 – The Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, FASB released SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment to FASB Statement No. 115.” SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. A business entity must report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 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 effective January 1, 2008. The adoption of SFAS No. 159 did not have a material impact on our consolidated financial statements.

SFAS No. 157 – Fair Value Measurements

In September 2006, FASB released SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 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. In February 2008, FASB issued FSP 157-2 which delays the effective date of SFAS No. 157 for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. The non-financial items subject to the deferral include assets and liabilities such as non-financial assets and liabilities assumed in a business combination, reporting units measured at fair value in a goodwill impairment test and asset retirement obligations initially measured at fair value. We adopted SFAS No. 157 for financial assets and liabilities recognized at fair value on a recurring basis effective January 1, 2008. The adoption of SFAS No. 157 did not have a material impact on our consolidated financial statements. See Note 4 of the Notes to Consolidated Financial Statements, "Financial and Derivative Instruments, Energy Marketing and Risk Management."

Allowance for Funds Used During Construction

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

	Year Ended December 31,		
	2008	2007	2006
		(In Thousands)	
Borrowed funds	$20,536	$13,090	$4,053
Equity funds	18,284	4,346	—
Total	$38,820	$17,436	$4,053
Average AFUDC Rates	6.4%	6.6%	5.3%

We expect both AFUDC for borrowed funds and equity funds to fluctuate over the next several years as we add generating capacity, expand our transmission system and make significant environmental improvements.

Interest Expense

We expect interest expense to increase significantly over the next several years as we issue new debt securities to fund our capital expenditures program. We believe the increase in interest expense will be recovered from our customers in future rate proceedings.

Wholesale Sales Margins

Previously, 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. As a result of the 2009 KCC Order, the amount to be credited back to retail customers, beginning approximately March 1, 2009, will be based on the actual margins realized from market-based wholesale sales.

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 sell of electricity and fuel procurement for our generating units. 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 goals of reducing risk from market fluctuations, 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 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 statements. Our risk of loss is mitigated through the use of the RECA and similar adjustment mechanisms that we maintain for many of our wholesale sales contracts and tariffs.

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

We manage and measure the market price risk exposure of our trading portfolio 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 2009. The use of VaR requires assumptions, including the selection of a confidence level for 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. 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 2008 and 2007 were as follows:

	2008	2007
	(In Thousands)	
High	$1,660	$1,966
Low	127	176
Average	983	639

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.

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 $493.2 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2008. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $4.0 million. As of December 31, 2008, we had $171.9 million of variable rate bonds insured by bond insurers. Interest rates payable under these bonds are set at periodic auctions. Conditions in the credit markets have caused the demand for auction bonds to decline generally and have caused our borrowing costs to increase. Additionally, should those bond insurers experience a decrease in credit rating, such event would most likely increase our borrowing costs as well. In addition, a decline in interest rates generally can serve to increase our pension and post retirement 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, 2008, investments by the nuclear decommissioning trust fund were allocated 64% to equity securities, 26% to debt securities, 7% to real estate, 2% to commodities and 1% to cash and cash equivalents. The fair value of these funds was $85.6 million as of December 31, 2008, and $122.3 million as of December 31, 2007. We also maintain a trust that is used to fund retirement benefits. As of December 31, 2008, these funds were comprised of 51% equity securities, 36% debt securities and 13% cash and cash equivalents. The fair value of these funds was $26.3 million as of December 31, 2008, and $37.1 million as of December 31, 2007. By maintaining diversified portfolios of securities, we seek to maximize the returns to fund these obligations within acceptable risk tolerances. 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 equity price market risk related to the nuclear decommissioning fund is, in part, mitigated because we are currently allowed to recover decommissioning costs in the rates we charge our customers.

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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 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 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
- 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, 2008. 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, 2008, 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, 2008, 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, 2008, 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, 2008 of the Company and our report dated February 26, 2009 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company’s adoption of a new accounting standard.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 26, 2009

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, 2008 and 2007, and the related consolidated statements of income, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 10 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board (FASB) Interpretation No. FIN 48, “Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No.109” as of January 1, 2007.

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, 2008, 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 26, 2009 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 26, 2009

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

	As of December 31, 2008	As of December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 22,914	$ 5,753
Accounts receivable, net of allowance for doubtful accounts of $4,810 and $5,721, respectively	199,116	195,785
Inventories and supplies, net	204,297	192,533
Energy marketing contracts	131,647	57,702
Taxes receivable	36,462	71,111
Deferred tax assets	16,416	—
Prepaid expenses	33,419	31,576
Regulatory assets	79,783	98,204
Other	19,077	15,015
Total Current Assets	743,131	667,679
PROPERTY, PLANT AND EQUIPMENT, NET	5,533,521	4,803,672
OTHER ASSETS:		
Regulatory assets	872,487	577,256
Nuclear decommissioning trust	85,555	122,298
Energy marketing contracts	25,601	34,088
Other	182,964	190,437
Total Other Assets	1,166,607	924,079
TOTAL ASSETS	$7,443,259	$6,395,430
LIABILITIES AND SHAREHOLDERS’ EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 146,366	$ 558
Short-term debt	174,900	180,000
Accounts payable	195,683	278,299
Accrued taxes	44,008	47,370
Energy marketing contracts	104,622	42,641
Accrued interest	42,142	41,416
Deferred tax liabilities	—	2,310
Regulatory liabilities	31,123	32,932
Other	133,565	119,237
Total Current Liabilities	872,409	744,763
LONG-TERM LIABILITIES:		
Long-term debt, net	2,192,538	1,889,781
Obligation under capital leases	117,909	123,854
Deferred income taxes	1,004,920	897,293
Unamortized investment tax credits	59,386	59,619
Deferred gain from sale-leaseback	114,027	119,522
Accrued employee benefits	526,177	283,924
Asset retirement obligations	95,083	88,711
Energy marketing contracts	2,262	7,647
Regulatory liabilities	91,934	108,685
Other	155,612	217,927
Total Long-Term Liabilities	4,359,848	3,796,963
COMMITMENTS AND CONTINGENCIES (see Notes 13 and 15)		
TEMPORARY EQUITY (See Note 11)	3,422	5,224
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 108,311,135 shares and 95,463,180 shares, respectively	541,556	477,316
Paid-in capital	1,326,391	1,085,099
Retained earnings	318,197	264,477
Accumulated other comprehensive income, net	—	152
Total Shareholders’ Equity	2,207,580	1,848,480
TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY	$7,443,259	$6,395,430

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,		
	2008	2007	2006
SALES	$ 1,838,996	$ 1,726,834	$ 1,605,743
OPERATING EXPENSES:			
Fuel and purchased power	694,348	544,421	483,959
Operating and maintenance	471,838	473,525	463,785
Depreciation and amortization	203,738	192,910	180,228
Selling, general and administrative	184,427	178,587	171,001
Total Operating Expenses	1,554,351	1,389,443	1,298,973
INCOME FROM OPERATIONS	284,645	337,391	306,770
OTHER INCOME (EXPENSE):			
Investment (loss) earnings	(10,453)	6,031	9,212
Other income	29,658	6,726	18,000
Other expense	(15,324)	(14,072)	(13,711)
Total Other Income (Expense)	3,881	(1,315)	13,501
Interest expense	106,450	103,883	98,650
INCOME BEFORE INCOME TAXES	182,076	232,193	221,621
Income tax expense	3,936	63,839	56,312
NET INCOME	178,140	168,354	165,309
Preferred dividends	970	970	970
EARNINGS AVAILABLE FOR COMMON STOCK	$ 177,170	$ 167,384	$ 164,339
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (see Note 2):			
Basic earnings available	$ 1.70	$ 1.85	$ 1.88
Diluted earnings available	$ 1.70	$ 1.83	$ 1.87
Average equivalent common shares outstanding	103,958,414	90,675,511	87,509,800
DIVIDENDS DECLARED PER COMMON SHARE	$ 1.16	$ 1.08	$ 1.00

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,		
	2008	2007	2006
NET INCOME	$178,140	$168,354	$165,309
OTHER COMPREHENSIVE INCOME (LOSS):			
Unrealized holding gain (loss) on marketable securities arising during the period	—	51	(57)
Minimum pension liability adjustment	—	—	31,841
Other comprehensive income, before tax	—	51	31,784
Income tax expense related to items of other comprehensive income	—	—	(12,666)
Other comprehensive income, net of tax	—	51	19,118
COMPREHENSIVE INCOME	$178,140	$168,405	$184,427

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,		
	2008	2007	2006
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$ 178,140	$ 168,354	$ 165,309
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	203,738	192,910	180,228
Amortization of nuclear fuel	14,463	16,711	13,851
Amortization of deferred gain from sale-leaseback	(5,495)	(5,495)	(5,495)
Amortization of corporate-owned life insurance	18,920	13,693	15,336
Non-cash compensation	4,696	5,800	3,389
Net changes in energy marketing assets and liabilities	(7,018)	7,647	(7,505)
Accrued liability to certain former officers	(1,449)	931	3,813
Gain on sale of utility plant and property	(1,053)	—	(570)
Net deferred income taxes and credits	35,261	14,084	(4,203)
Stock based compensation excess tax benefits	(561)	(1,058)	(854)
Allowance for equity funds used during construction	(18,284)	(4,346)	—
Changes in working capital items, net of acquisitions and dispositions:			
Accounts receivable	(3,331)	(15,926)	(55,148)
Inventories and supplies	(11,764)	(44,603)	(46,112)
Prepaid expenses and other	(52,615)	(72,212)	(4,095)
Accounts payable	(73,971)	59,488	22,625
Accrued taxes	27,938	(50,027)	(13,160)
Other current liabilities	(5,732)	(50,179)	(5,708)
Changes in other assets	29,389	(54,668)	19,412
Changes in other liabilities	(56,382)	65,712	(25,127)
Cash flows from operating activities	274,890	246,816	255,986
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(937,242)	(748,156)	(344,860)
Allowance for equity funds used during construction	18,284	4,346	—
Investment in corporate-owned life insurance	(18,720)	(18,793)	(19,127)
Purchase of securities within the nuclear decommissioning trust fund	(210,599)	(240,067)	(345,541)
Sale of securities within the nuclear decommissioning trust fund	221,613	238,414	341,410
Proceeds from investment in corporate-owned life insurance	27,320	544	22,684
Proceeds from sale of plant and property	4,295	—	1,695
Other investing activities	(11,388)	—	—
Proceeds from other investments	—	1,653	53,411
Cash flows used in investing activities	(906,437)	(762,059)	(290,328)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	(5,100)	20,000	160,000
Proceeds from long-term debt	544,715	322,284	99,662
Retirements of long-term debt	(101,311)	(25)	(200,000)
Repayment of capital leases	(9,820)	(5,729)	(4,813)
Borrowings against cash surrender value of corporate-owned life insurance	64,255	61,472	59,697
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(28,634)	(2,209)	(24,133)
Stock based compensation excess tax benefits	561	1,058	854
Issuance of common stock, net	293,621	195,420	2,394
Cash dividends paid	(109,579)	(89,471)	(80,894)
Cash flows from financing activities	648,708	502,800	12,767
CASH FLOWS FROM DISCONTINUED OPERATIONS:			
Cash flows from investing activities	—	—	1,232
Cash from discontinued operations	—	—	1,232
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	17,161	(12,443)	(20,343)
CASH AND CASH EQUIVALENTS:			
Beginning of period	5,753	18,196	38,539
End of period	$ 22,914	$ 5,753	$ 18,196

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	Unearned compensation	Retained earnings	Accumulated other comprehensive (loss) income	Total Shareholders' Equity
Balance at December 31, 2005	$ 21,436	$434,177	$ 923,083	$ (10,257)	$ 109,987	$ (40,987)	$ 1,437,439
Net income	—	—	—	—	165,309	—	165,309
Issuance of common stock, net	—	2,797	9,585	—	—	—	12,382
Preferred dividends, net of retirements	—	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	—	(88,547)	—	(88,547)
Reclass to Temporary Equity	—	—	(6,671)	—	—	—	(6,671)
Reclass of unearned compensation	—	—	(10,257)	10,257	—	—	—
Amortization of restricted stock	—	—	2,956	—	—	—	2,956
Stock compensation and tax benefit	—	—	(2,091)	—	—	—	(2,091)
Unrealized loss on marketable securities	—	—	—	—	—	(57)	(57)
Minimum pension liability adjustment	—	—	—	—	—	31,841	31,841
Income tax expense	—	—	—	—	—	(12,666)	(12,666)
Reclass to regulatory asset	—	—	—	—	—	21,970	21,970
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 – FIN 48	—	—	—	—	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 – SFAS 158	—	—	—	—	(495)	—	(495)
Adjustment to Retained Earnings – SFAS 159	—	—	—	—	152	(152)	—
Balance at December 31, 2008	$ 21,436	$541,556	$1,326,391	$ —	$ 318,197	$ —	$ 2,207,580

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

WESTAR ENERGY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

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

We provide electric generation, transmission and distribution services to approximately 679,000 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 generally accepted accounting principles (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 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 and post-employment benefits, our asset retirement obligations 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 for our regulated utility operations that recognize the economic effects of rate regulation in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," and, accordingly, 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 rates. Regulatory liabilities represent probable future reductions in revenue or refunds to customers through the rate making process. Regulatory assets and liabilities reflected on our consolidated balance sheets are as follows.

	As of December 31,	
	2008	2007
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$440,061	$202,545
Amounts due from customers for future income taxes, net	193,997	151,279
Debt reacquisition costs	87,321	91,110
Depreciation	85,104	64,665
Ice storm costs	68,109	81,462
Asset retirement obligations	21,542	20,071
Retail energy cost adjustment	17,991	32,794
Disallowed plant costs	16,560	16,650
Wolf Creek outage	12,442	6,984
Other regulatory assets	9,143	7,900
Total regulatory assets	$952,270	$675,460
Regulatory Liabilities:		
Removal costs	$ 50,051	$ 25,157
Fuel supply and capacity sale contracts	36,331	34,042
Nuclear decommissioning	15,054	56,006
Ad valorem tax	7,347	3,846
State Line purchased power	3,379	5,001
Retail energy cost adjustment	456	6,015
Other regulatory liabilities	10,439	11,550
Total regulatory liabilities	$123,057	$141,617

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

- **Deferred employee benefit costs:** Employee benefit costs include $441.2 million, less $2.6 million for applicable taxes, for pension and post-retirement benefit obligations pursuant to SFAS No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Post-retirement Plans – An Amendment of FASB Statements No. 87, 88, 106, and 132(R)” and $1.5 million for post-retirement expenses in excess of amounts paid. We will amortize to expense approximately $26.5 million during 2009 for the benefit obligation. The post-retirement expenses are recovered over a period of five years.

- **Amounts due from customers for future income taxes, net:** In accordance with various rate orders, we have reduced rates 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. We have recorded a regulatory asset for these amounts. We also have recorded a regulatory liability for our obligation to customers for taxes recovered from customers in earlier periods when corporate tax rates were higher than the current tax rates. The 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 through future rates.

- **Debt reacquisition costs:** This includes costs incurred to reacquire and refinance debt. Debt reacquisition costs are amortized over the term of the new debt.

- **Depreciation:** This represents the difference between the regulatory depreciation expense and the depreciation expense we record for financial reporting purposes. We earn a return on this asset. We recover this item over the life of the related utility plant.

- **Ice storm costs:** We accumulated and deferred for future recovery costs related to restoring our electric transmission and distribution systems from damage sustained during ice storms. We recover these costs over periods ranging from three to five years. We earn a return on this asset.

- **Asset retirement obligations:** This represents amounts associated with our asset retirement obligations as discussed in Note 14, "Asset Retirement Obligations." We recover this item over the life of the utility plant.

- **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 rates this shortfall over a one year period. We have two retail jurisdictions, each of which has a unique RECA and a separate cost of fuel. This can result in our simultaneously reporting both a regulatory asset and a regulatory liability for this item.

- **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 rates over the useful life of Wolf Creek.

- **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 of time between such planned outages.

- **Other regulatory assets:** This item 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:** This represents amounts collected, but unspent, for costs to dispose of utility plant assets that do not represent legal retirement obligations. The liability will be discharged as removal costs are incurred.

- **Fuel supply and capacity sale contracts:** We use mark-to-market accounting for some of our fuel supply and capacity sale contracts. This item represents the non-cash net gain position on fuel supply and capacity sale contracts that are marked-to-market in accordance with the requirements of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Under the RECA, fuel supply contract market gains accrue to the benefit of our customers.

- **Nuclear decommissioning:** We have a legal obligation to decommission Wolf Creek at the end of its useful life. This amount represents the difference between the fair value of our asset retirement obligation 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 asset retirement obligation.

- **Ad valorem tax:** This represents amounts collected in rates in excess of costs incurred for property taxes. We will refund to customers this excess recovery over a one year period.

- **State Line purchased power:** This 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.

- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. We bill customers based on our estimated costs. This item represents the amount we collected from customers that was in excess of our actual cost of fuel and purchased power. We will refund to customers this excess recovery over a one year period. We have two retail jurisdictions, each of which has a unique RECA and a separate cost of fuel. This can result in our simultaneously reporting both a regulatory asset and a regulatory liability for this item.

- **Other regulatory liabilities:** This 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 that 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 utility 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 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,		
	2008	2007	2006
	(In Thousands)		
Borrowed funds	$20,536	$13,090	$4,053
Equity funds	18,284	4,346	—
Total	$38,820	$17,436	$4,053
Average AFUDC Rates	6.4%	6.6%	5.3%

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 amortize those maintenance costs to expense ratably over the 18-month period between such scheduled 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 2.6% in 2008 and 2.7% in both 2007 and 2006.

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

	Years
Fossil fuel generating facilities	25 to 75
Nuclear fuel generating facility	40 to 60
Transmission facilities	15 to 65
Distribution facilities	19 to 65
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 $29.3 million as of December 31, 2008, and $36.4 million as of December 31, 2007. Spent nuclear fuel charged to fuel and purchased power expense was $18.3 million in 2008, $21.7 million in 2007 and $18.8 million in 2006.

Cash Surrender Value of Life Insurance

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

	As of December 31,	
	2008	2007
	(In Thousands)	
Cash surrender value of policies	$ 1,156,457	$ 1,117,828
Borrowings against policies	(1,066,776)	(1,031,155)
Corporate-owned life insurance, net	$ 89,681	$ 86,673

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 $9.5 million in 2008, $2.4 million in 2007 and $18.9 million in 2006.

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 the electric usage from the last meter read and record the corresponding unbilled revenue.

The accuracy of our unbilled revenue estimate is affected by factors including fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $47.7 million as of December 31, 2008, and $43.7 million as of December 31, 2007.

We account for energy marketing derivative contracts under the mark-to-market 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 a fuel supply contract and a capacity sale contract, which we record as regulatory liabilities, we include the net mark-to-market change in sales 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 is 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 statements.

Income Taxes

We use the asset and liability method of accounting for income taxes as required by SFAS No. 109, “Accounting for Income Taxes.” Under the asset and liability 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.

As of January 1, 2007, we account for uncertainty in income taxes in accordance with FASB Interpretation No. (FIN) 48. The application of income tax law is complex. Laws and regulations in this area are voluminous and are often ambiguous. Accordingly, we must make subjective assumptions and judgments regarding income tax exposures. Interpretations of and guidance surrounding income tax laws and regulations change over time. As a result, changes in our subjective assumptions and judgments can materially affect amounts we recognize in the consolidated financial statements. See Note 10, “Taxes,” for additional detail of our uncertainty in 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.

Dilutive Shares

We report basic earnings per share applicable to equivalent common stock based on the weighted average number of common shares outstanding and shares issuable in connection with vested restricted share units (RSU) during the period reported. Diluted earnings per share includes the effects of potential issuances of common shares resulting from the assumed vesting of all outstanding RSUs, the exercise of all outstanding stock options issued pursuant to the terms of our stock-based compensation plans and the physical settlement of a forward sale agreement. We compute the dilutive effect of shares issuable under our stock-based compensation plans and forward sale agreement using the treasury stock method.

The following table reconciles the weighted average number of equivalent common shares outstanding used to compute basic and diluted earnings per share.

	Year Ended December 31,		
	2008	2007	2006
DENOMINATOR FOR BASIC AND DILUTED EARNINGS PER SHARE:			
Denominator for basic earnings per share – weighted average equivalent shares	103,958,414	90,675,511	87,509,800
Effect of dilutive securities:			
Employee stock options	728	952	788
Restricted share units	448,314	517,694	589,352
Forward sale agreement	—	66,686	—
Denominator for diluted earnings per share – weighted average equivalent shares	104,407,456	91,260,843	88,099,940
Potentially dilutive shares not included in the denominator because they are antidilutive	21,300	74,890	158,080

Supplemental Cash Flow Information

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$102,865	$ 84,291	$88,872
Income taxes, net of refunds	(34,905)	74,970	72,407
NON-CASH INVESTING TRANSACTIONS:			
Jeffrey Energy Center 8% leasehold interest	—	118,538	—
Other property, plant and equipment additions	106,219	100,039	29,134
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and RSUs	11,263	10,553	10,094
Capital lease for Jeffrey Energy Center 8% leasehold interest	—	118,538	—
Other assets acquired through capital leases	4,583	3,228	4,491

New Accounting Pronouncements

FSP No. EITF 03-6-1 – Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities

In June 2008, FASB released Staff Position (FSP) No. Emerging Issues Task Force (EITF), 03-6-1, “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.” FSP No. EITF 03-6-1 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 earnings per share pursuant to the two-class method. FSP No. EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. We do not expect the adoption of this guidance to have a material impact on our earnings per share.

SFAS No. 161 – Disclosures about Derivative Instruments and Hedging Activities

In March 2008, FASB released SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities – An Amendment of FASB Statement No. 133”, which requires expanded disclosure intended to help investors better understand how derivative instruments and hedging activities affect an entity’s financial position, financial performance and cash flows. SFAS No. 161 amends and expands our disclosure requirements related to SFAS No. 133, “Accounting for 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. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008.

SFAS No. 159 – The Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, FASB released SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment to FASB Statement No. 115.” SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. A business entity must report unrealized gains and losses on items for which fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 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 effective January 1, 2008. The adoption of SFAS No. 159 did not have a material impact on our consolidated financial statements.

SFAS No. 157 – Fair Value Measurements

In September 2006, FASB released SFAS No. 157, “Fair Value Measurements.” SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 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. In February 2008, FASB issued FSP 157-2 which delays the effective date of SFAS No. 157 for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. The non-financial items subject to the deferral include assets and liabilities such as non-financial assets and liabilities assumed in a business combination, reporting units measured at fair value in a goodwill impairment test and asset retirement obligations initially measured at fair value. We adopted SFAS No. 157 for financial assets and liabilities recognized at fair value on a recurring basis effective January 1, 2008. The adoption of SFAS No. 157 did not have a material impact on our consolidated financial statements. See Note 4, “Financial and Derivative Instruments, Energy Marketing and Risk Management.”

3. RATE MATTERS AND REGULATION

KCC Proceedings

Changes in Rates

We filed an application with the KCC in May 2008 to increase retail rates by $177.6 million per year. The primary drivers for this application were investments in natural gas generation facilities, wind generation facilities, and other capital projects, costs attributable to the 2007 ice storm, higher operating costs and an update of our capital structure. On October 27, 2008, all parties to the proceeding filed an agreement with the KCC supporting a $130.0 million annual increase in our retail rates. On January 21, 2009, the KCC issued an order approving the settlement agreement and the new retail rates became effective on February 3, 2009.

On July 1, 2008, we implemented an initial retail transmission delivery charge (TDC) on a revenue neutral basis to capture transmission costs ultimately approved in our 2005 general rate case. On September 18, 2008, the KCC granted our request to adjust the TDC to include more recent transmission costs approved by the Federal Energy Regulatory Commission (FERC) and attributable to the retail portion of our transmission service. This served to increase our estimated annual retail revenues by $6.1 million.

On May 29, 2008, the KCC issued an order allowing us to increase our environmental cost recovery rider (ECRR) to include costs associated with investments made in 2007. This change went into effect on June 1, 2008, and served to increase our estimated annual retail revenues by $22.0 million.

On December 28, 2005, the KCC issued the 2005 KCC Order authorizing changes in our rates, which we began billing in the first quarter of 2006, and approving various other changes in our rate structures. In April 2006, interveners to the rate review filed appeals with the Kansas Court of Appeals challenging various aspects of the 2005 KCC Order. On July 7, 2006, the Kansas Court of Appeals reversed and remanded for further consideration by the KCC three elements of the 2005 KCC Order (July 2006 Court Order). The balance of the 2005 KCC Order was upheld.

The Kansas Court of Appeals held: (i) the KCC's approval of a TDC, in the circumstances of this case, violated the Kansas statutes that authorize a TDC, (ii) the KCC's approval of recovery of terminal net salvage, adjusted for inflation, in our depreciation rates was not supported by substantial competent evidence, and (iii) the KCC's reversal of its prior rate treatment of the La Cygne Generating Station (La Cygne) unit 2 sale-leaseback transaction was not sufficiently justified and was thus unreasonable, arbitrary and capricious.

On February 8, 2007, the KCC issued an order in response to the July 2006 Court Order (February 2007 KCC Order). The February 2007 KCC Order: (i) confirmed the original decision regarding treatment of the La Cygne unit 2 sale-leaseback transaction; (ii) reversed the KCC's original decision with regard to the inclusion in depreciation rates of a component for terminal net salvage; and (iii) permits recovery of transmission related costs in a manner similar to how we recover our other costs. On November 30, 2007, we filed with the KCC to implement a separate TDC in a manner consistent with the applicable Kansas statute. The February 2007 KCC Order required us to refund to our customers amounts we collected related to terminal net salvage. On July 31, 2007, the KCC issued an order (July 2007 KCC Order) resolving issues raised by us and interveners following the February 2007 KCC Order. The July 2007 KCC Order: (i) confirmed the earlier decision concerning recovery of terminal net salvage and quantified the effect of that ruling; and (ii) approved a Stipulation and Agreement between us and the KCC Staff. The Stipulation and Agreement approved by the KCC quantified the refund obligation related to amounts previously collected from customers for transmission related costs and established the amount of transmission costs to be included in retail rates, prospectively. Interveners filed petitions for reconsideration of the July 2007 KCC Order on August 15, 2007. These petitions were denied by the KCC on September 13, 2007. The interveners filed appeals with the Kansas Court of Appeals. On February 11, 2008, the Kansas Court of Appeals issued an opinion which affirmed the July 2007 KCC Order. We filed new tariffs and a plan for implementing refunds that became effective on August 29, 2007. Refunds were substantially completed in November.

FERC Proceedings

Requests for Changes in Transmission Rates

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 (ROE) and a 15-year accelerated recovery for an approximately 100 mile, 345 kilovolt (kV) 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 by June 2010. We estimate the line will cost approximately $200.0 million.

In November 2007, we filed applications with FERC that proposed changes in the capital structure used in our transmission formula rate. FERC accepted the proposed changes and the rate change went into effect on June 1, 2007. At December 31, 2008, we had a $2.8 million refund obligation related to this matter, which includes the amount we have collected since June 1, 2007, plus interest on that amount.

On May 2, 2005, we filed applications with FERC that proposed a transmission formula rate providing for annual adjustments to our transmission tariff. This is consistent with our proposals filed with the KCC on May 2, 2005, to charge retail customers separately for transmission service through a TDC. In November 2007, FERC approved a settlement providing for the rate change effective December 1, 2005, and a refund to customers of $3.4 million.

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

Values of Financial and Derivative Instruments

We measure the fair value of each class of our financial and derivative instruments for which it is practicable to measure that value as set forth in SFAS No. 107, “Disclosures about Fair Value of Financial Instruments,” and SFAS No. 157, “Fair Value Measurements.”

Cash and cash equivalents, short-term borrowings and variable-rate debt are carried at cost, which approximates fair value. The fair value of fixed-rate debt is measured 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 amounts of accounts receivable and other current financial instruments approximate fair value.

The nuclear decommissioning trust is recorded at fair value using quoted market prices or valuation models utilizing observable market data when available. A portion of the trust assets is comprised of private equity investments or real estate that require significant unobservable market information to measure the fair value of the investments. The private equity investments are initially valued 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. The real estate investments are valued using market discount rates, projected cash flows and the estimated value into perpetuity. See Note 5, “Financial Investments and Trading Securities,” for additional information about investments held within the nuclear decommissioning trust fund.

The fair value of trading securities is measured using quoted market prices or valuation models utilizing observable market data. See Note 5, “Financial Investments and Trading Securities,” for additional information about investments classified as trading securities.

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, 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.

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We measure fair value based on information available as of December 31, 2008 and 2007. We show the carrying values and measured fair values of our financial instruments in the table below.

	Carrying Value		Fair Value	
	As of December 31,			
	2008	2007	2008	2007
	(In Thousands)			
Fixed-rate debt, net of current maturities (a)	$2,024,178	$1,619,381	$1,749,123	$1,586,407

(a) This amount does not include an equipment financing loan of $2.7 million and $1.8 million in 2008 and 2007, respectively.

Recurring Fair Value Measurements

Effective January 1, 2008, we adopted SFAS No. 157, which defines fair value and requires enhanced disclosures about assets and liabilities measured at fair value. SFAS No. 157 establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the SFAS No. 157 hierarchy and examples of each 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, 2008.

	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Energy Marketing Contracts	$ 1,600	$104,821	$50,827	$157,248
Nuclear Decommissioning Trust	46,997	30,524	8,034	85,555
Trading Securities (a)	13,420	9,503	—	22,923
Total	$62,017	$144,848	$58,861	$265,726
Liabilities:				
Energy Marketing Contracts	$ 1,594	$ 99,004	$ 6,286	$106,884

(a) The total does not include cash and cash equivalents recorded at cost, which are not subject to the fair value requirements set forth in SFAS No. 157.

We do not offset the fair value of energy marketing contracts executed with the same counterparty. As of December 31, 2008, we have 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 year ended December 31, 2008.

	Energy Marketing Contracts, net	Nuclear Decommissioning Trust	Net Balance
		(In Thousands)	
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)	(60)	12,229
Purchases, issuances and settlements	(7,435)	6,843	(592)
Balance as of December 31, 2008	$ 44,541	$ 8,034	$52,575

(a) Unrealized and realized gains and losses included in earnings are reported in sales.
(b) Regulatory liabilities include changes in the fair value of a fuel supply contract and a capacity sale contract.

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 recognized during the year ended December 31, 2008, attributed to level 3 assets and liabilities still held at December 31, 2008.

	Energy Marketing Contracts, net (In Thousands)
Total unrealized gains (losses) included in:	
Earnings	$ 2,842
Regulatory liabilities (a)	15,460
Total	$ 18,302

(a) Regulatory liabilities include changes in the fair value of a fuel supply contract and a capacity sale contract.

Derivative Instruments

We are exposed to market risks from changes in commodity prices and interest rates that could affect our consolidated financial statements. We manage our exposure to these market risks through our regular operating and financing activities and, when we deem appropriate, economically hedge a portion of these risks through the use of derivative financial instruments. We use the term economic hedge to mean a strategy designed to manage risks of volatility in prices or rate movements on some assets, liabilities or anticipated transactions by creating a relationship in which gains or losses on derivative instruments are expected to counterbalance the losses or gains on the assets, liabilities or anticipated transactions exposed to such market risks. We use derivative instruments as risk management tools consistent with our business plans, risk management practices and for energy marketing purposes.

We use derivative financial and physical instruments primarily to manage risk as it relates to changes in the prices of commodities including natural gas, diesel, oil, coal and electricity. We classify derivative instruments that we use to manage commodity price risk inherent in fossil fuel and electricity purchases and sales 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.

Energy Marketing Activities

We engage in both financial and physical trading to increase profits, manage our commodity price risk and enhance system reliability. We primarily 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.

Within the trading portfolio, we take certain positions to economically hedge a portion of physical sale or purchase contracts and we take certain positions attempting to take advantage of market trends and conditions. With the exception of a fuel supply contract and a capacity sale contract, which we record as regulatory liabilities, we include the net mark-to-market change in sales on our consolidated statements of income. We believe financial instruments help us manage our contractual commitments, reduce our exposure to changes in cash market prices and take advantage of market opportunities. We refer to these transactions as energy marketing activities.

We trade to reduce risk from market fluctuations, enhance system reliability and increase profits. 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 open positions, we are exposed to the risk that changing market prices could have a material, adverse impact on our consolidated financial statements.

We have considered a number of risks and costs associated with future contractual commitments in our energy portfolio. These risks include credit risks associated with the financial condition of counterparties, product location (basis) differentials 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 that, in management's view, reduce our overall credit risk.

We are exposed to commodity price changes. We use derivative contracts for non-trading purposes. We trade various types of fuel primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power and fuels markets are extremely volatile in price and supply. This volatility impacts our costs 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 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.

We use various types of fossil fuel, including coal, natural gas, diesel and oil, to operate our plants. A significant portion of our coal requirements is purchased under long-term contracts.

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. 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 facilities that use fossil fuels and the nuclear refueling schedule. Our customers' electricity usage could also vary from year to year based on weather or other factors.

The prices we use to value risk management activities reflect our estimates of fair values considering various factors, including closing exchange and OTC quotations, time value of money and price volatility factors underlying the commitments. We adjust prices to reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions. We consider a number of risks and costs associated with the future contractual commitments included in our energy portfolio, including credit risks associated with the financial condition of counterparties and the time value of money. We continuously monitor the portfolio and value it daily based on present market conditions.

5. FINANCIAL INVESTMENTS AND TRADING SECURITIES

Some of our investments in debt and equity securities are subject to the requirements of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." We report these investments at fair value and we 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 loss of $9.5 million as of December 31, 2008, an unrealized gain of $2.8 million as of December 31, 2007 and an unrealized gain of $1.7 million as of December 31, 2006.

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, 2008 and 2007. At December 31, 2008, investments by the nuclear decommissioning trust fund were allocated 64% to equity securities, 26% to debt securities, 7% to real estate, 2% to commodities and 1% 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, 2008, the fair value of the debt securities in the nuclear decommissioning trust fund was $22.6 million. Of this amount, $21.4 million was held in closed end funds, bond mutual funds and indexed bond funds. As of December 31, 2008, the average maturity of the bonds in these funds ranged from 4.0 years to 7.9 years.

Using the specific identification method to determine cost, we realized a $20.1 million loss in 2008, a $5.7 million gain in 2007 and a $7.5 million gain in 2006 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 rates. 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 electric rates 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, 2008 and 2007.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In Thousands)		
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
2007:				
Equity securities	$ 69,505	$19,031	$ (2,971)	$ 85,565
Debt securities	33,705	450	(528)	33,627
Cash equivalents	3,106	—	—	3,106
Total	$106,316	$19,481	$ (3,499)	$ 122,298

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, at December 31, 2008.

	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	$ 40,149	$ (15,630)	$ 290	$ (821)	$ 40,439	$ (16,451)
Debt securities	9,382	(2,791)	310	(177)	9,692	(2,968)
Real estate	6,000	(74)	—	—	6,000	(74)
Commodities	1,459	(1,052)	—	—	1,459	(1,052)
Total	$ 56,990	$ (19,547)	$ 600	$ (998)	$ 57,590	$ (20,545)

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6. PROPERTY, PLANT AND EQUIPMENT

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

	As of December 31, 2008	2007
	(In Thousands)	
Electric plant in service	$ 7,182,589	$ 6,452,522
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,249,007)	(3,142,550)
	4,735,900	4,112,290
Construction work in progress	733,816	630,782
Nuclear fuel, net	63,771	60,566
Net utility plant	5,533,487	4,803,638
Non-utility plant in service	34	34
Net property, plant and equipment	$ 5,533,521	$ 4,803,672

We recorded depreciation expense on utility property, plant and equipment of $180.8 million in 2008, $170.0 million in 2007 and $159.9 million in 2006.

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, 2008, is shown in the table below.

		Our Ownership as of December 31, 2008 In-Service Dates		Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percent
				(Dollars in Thousands)				
La Cygne unit 1	(a)	June	1973	$ 275,615	$ 130,856	$ 12,968	368	50
Jeffrey unit 1	(a)	July	1978	426,667	176,780	24,994	665	92
Jeffrey unit 2	(a)	May	1980	321,826	168,139	115,822	661	92
Jeffrey unit 3	(a)	May	1983	574,289	233,763	53,718	665	92
Wolf Creek	(b)	Sept.	1985	1,459,271	687,135	25,901	545	47
State Line	(c)	June	2001	107,216	32,443	144	204	40
Total				$3,164,884	$ 1,429,116	$ 233,547	3,108	

(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 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 January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to 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 15, 2008, FERC granted our request and on February 22, 2008, a syndicate of banks in the credit facility increased their commitments to $750.0 million in the aggregate. Effective February 22, 2008, $730.0 million of the commitments of the lenders under the revolving credit facility terminate on March 17, 2012. The remaining $20.0 million of the commitments terminate on March 17, 2011.

Lehman Brothers Commercial Paper, Inc. (Lehman Brothers) is the participating lender with respect to a $20.0 million commitment terminating 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 0.88% and 6.18% as of December 31, 2008, and December 31, 2007, respectively. As of February 18, 2009, $230.2 million had been borrowed and an additional $21.1 million of letters of credit had been issued under the revolving credit facility.

Information regarding our short-term borrowings is as follows.

	As of December 31,	
	2008	2007
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$ 270,756	$ 157,372
Weighted daily average interest rates during the year, excluding fees	3.31%	5.83%

Our interest expense on short-term debt was $9.7 million in 2008 and 2007 and $7.6 million in 2006.

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9. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

	As of December 31, 2008	As of December 31, 2007
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
6.000% due 2014	$ 250,000	$ 250,000
5.150% due 2017	125,000	125,000
5.950% due 2035	125,000	125,000
5.100% due 2020	250,000	250,000
5.875% due 2036	150,000	150,000
6.100% due 2047	150,000	150,000
8.625% due 2018	300,000	—
	1,350,000	1,050,000
Pollution control bond series:		
Variable due 2032, 2.750% as of December 31, 2008; 4.350% as of December 31, 2007	45,000	45,000
Variable due 2032, 2.310% as of December 31, 2008; 4.350% as of December 31, 2007	30,500	30,500
5.000% due 2033	58,215	58,340
	133,715	133,840
Other long-term debt:		
4.360% Equipment financing loan due 2010	2,694	1,825
7.125% unsecured senior notes due 2009	145,078	145,078
	147,772	146,903
KGE		
First mortgage bond series:		
6.530% due 2037	175,000	175,000
6.150% due 2023	50,000	—
6.640% due 2038	100,000	—
	325,000	175,000
Pollution control bond series:		
5.100% due 2023	13,463	13,463
Variable due 2027, 1.950% as of December 31, 2008; 5.250% as of December 31, 2007	21,940	21,940
5.300% due 2031	108,600	108,600
5.300% due 2031	18,900	18,900
Variable due 2031, 5.000% as of December 31, 2007	—	100,000
Variable due 2032, 1.950% as of December 31, 2008; 5.250% as of December 31, 2007	14,500	14,500
Variable due 2032, 1.950% as of December 31, 2008; 4.500% as of December 31, 2007	10,000	10,000
4.850% due 2031	50,000	50,000
Variable due 2031, 1.647% as of December 31, 2008; 5.250% as of December 31, 2007	50,000	50,000
5.600% due 2031	50,000	—
6.000% due 2031	50,000	—
	387,403	387,403
Total long-term debt	2,343,890	1,893,146
Unamortized debt discount (a)	(4,986)	(2,807)
Long-term debt due within one year	(146,366)	(558)
Long-term debt, net	$2,192,538	$1,889,781

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

The Westar Energy mortgage and the KGE mortgage 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's first mortgage bonds authorized by its Mortgage and Deed of Trust, dated July 1, 1939, as supplemented, is unlimited subject to certain limitations as described below. The amount of KGE's first mortgage bonds authorized by the KGE Mortgage and Deed of Trust, dated April 1, 1940, as supplemented, is limited to a maximum of $2.0 billion, unless amended. 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, 2008, based on an assumed interest rate of 7.50%, approximately $138.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage. As of December 31, 2008, based on an assumed interest rate of 7.50%, approximately $415.0 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, 2008, we had $171.9 million of variable rate, tax-exempt bonds. Interest rates payable under these bonds have historically been set by auctions, which occur every 35 days. During 2008, auctions for these bonds failed, resulting in alternative index-based interest rates for these bonds of between 1% and 14%. On July 31, 2008, the KCC approved our request to remarket or refund all or part of these auction rate bonds, at our discretion. On August 26, 2008, we completed the refunding of $50.0 million of auction rate bonds at a fixed interest rate of 5.60% and a maturity date of June 1, 2031. On October 10, 2008, we completed the refunding of an additional $50.0 million of auction rate bonds at a fixed interest rate of 6.00% and a maturity date of June 1, 2031. We continue to monitor the credit markets and evaluate our options with respect to the remaining auction rate bonds.

On November 25, 2008, Westar Energy issued $300.0 million principal amount of first mortgage bonds at a discount to yield 8.750%, but bearing 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 December 2007, we entered into a $1.8 million equipment financing loan agreement with a term of 36 months to finance the cost of certain computer equipment purchased in 2007. In January 2008, we increased the size of this loan by $2.1 million to $3.9 million for equipment purchases made in 2008. As of December 31, 2008, the balance of this loan was $2.7 million.

On October 15, 2007, KGE issued $175.0 million principal amount of 6.53% first mortgage bonds maturing in 2037 in a private placement to an institutional investor.

On May 16, 2007, Westar Energy sold $150.0 million aggregate principal amount of 6.10% Westar Energy first mortgage bonds maturing in 2047.

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, 2008.

Maturities

Maturities of long-term debt as of December 31, 2008, are as follows.

Year	Principal Amount (In Thousands)
2009	$ 146,366
2010	1,345
2011	61
2012	—
Thereafter	2,196,118
Total long-term debt maturities	$ 2,343,890

Our interest expense on long-term debt was $95.7 million in 2008, $94.2 million in 2007 and $91.0 million in 2006.

10. TAXES

Income tax expense is composed of the following components.

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Income Tax Expense (Benefit) from Continuing Operations:			
Current income taxes:			
Federal	$(16,484)	$40,648	$46,211
State	(14,841)	9,107	14,303
Deferred income taxes:			
Federal	35,818	9,962	(1,150)
State	2,147	6,240	578
Investment tax credit amortization	(2,704)	(2,118)	(3,630)
Income tax expense from continuing operations	$ 3,936	$63,839	$56,312

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

	December 31,	
	2008	2007
	(In Thousands)	
Current deferred tax assets	$ 16,416	$ —
Current deferred tax liabilities	—	2,310
Non-current deferred tax liabilities	1,004,920	897,293
Net deferred tax liabilities	$ 988,504	$899,603

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

	December 31, 2008	December 31, 2007
	(In Thousands)	
Deferred tax assets:		
Capital loss carryforward (a)	$ 215,946	$ 216,626
Deferred employee benefit costs	176,061	82,752
Deferred gain on sale-leaseback	50,218	52,616
Accrued liabilities	33,038	29,248
Disallowed costs	14,648	15,301
Alternative minimum tax carryforward (b)	7,811	357
Long-term energy contracts	7,088	8,262
Business tax credit carryforward (c)	6,528	1,488
Other	61,206	91,951
Total gross deferred tax assets	572,544	498,601
Less: Valuation allowance (a)	219,537	220,146
Deferred tax assets	$ 353,007	$ 278,455
Deferred tax liabilities:		
Accelerated depreciation	$ 709,097	$ 644,707
Acquisition premium	211,972	219,985
Amounts due from customers for future income taxes, net	179,283	151,279
Deferred employee benefit costs	173,457	79,693
Other	67,702	82,394
Total deferred tax liabilities	$1,341,511	$1,178,058
Net deferred tax liabilities	$ 988,504	$ 899,603

(a) As of December 31, 2008, we have a net capital loss of $545.1 million which is available to offset future capital gains. Of this amount $544.6 million will expire in 2009 and $0.5 million will expire in 2013. As we do not expect to realize any significant capital gains in the future, a valuation allowance of $215.7 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 $219.5 million as of December 31, 2008, and $220.1 million as of December 31, 2007. The net reduction in valuation allowance of $0.6 million was due primarily to a reduction in the state corporate income tax rate in 2008. See the discussion below regarding the settlement with the Internal Revenue Service (IRS) Office of Appeals for years 2003 and 2004.

(b) As of December 31, 2008, we had available alternative minimum tax credit carryforwards of $7.8 million. These tax credits have an unlimited carryforward period.

(c) As of December 31, 2008, we had available federal general business tax credits of $3.2 million and state investment tax credits of $3.3 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 2019 through 2025. We recognized $14.6 million in 2008 for state tax incentives related to investment and jobs creation within the state of Kansas. The state investment tax credits expire beginning 2012. We believe these tax credits will be fully utilized before expiration.

In accordance with various rate orders, we have reduced rates to reflect the tax benefits associated with certain 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 rates charged customers for deferred taxes recovered from customers at corporate tax rates higher than the current tax rates. The rate 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 income 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 tax rates and the federal statutory income tax rates are as follows.

	For the Year Ended December 31,		
	2008	2007	2006
Statutory federal income tax rate from continuing operations	35.0%	35.0%	35.0%
Effect of:			
(Resolution) establishment of uncertain tax positions	(15.4)	0.6	0.7
Corporate-owned life insurance policies	(9.1)	(5.8)	(8.3)
State income taxes	(4.5)	4.4	4.4
AFUDC equity	(3.5)	(0.6)	—
Accelerated depreciation flow through and amortization	2.3	2.7	1.4
Amortization of investment tax credits	(1.5)	(0.9)	(1.6)
Net operating loss utilization	—	(5.1)	(0.9)
Capital loss utilization	—	(1.2)	(4.0)
Other	(1.1)	(1.6)	(1.3)
Effective income tax rate from continuing operations	2.2%	27.5%	25.4%

We file income tax returns in the U.S. federal jurisdiction, and various states and foreign jurisdictions. The income tax returns we filed 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 years before 2003. Our 2007, 2006, and 2005 income tax returns are subject to audit by federal and state taxing authorities.

The IRS has examined our federal income tax returns for the years 1995 through 2002. In December 2007, we tentatively reached a settlement with the IRS Office of Appeals on issues principally related to the method used to capitalize overheads to electric plant. This settlement, which was approved by the Joint Committee on Taxation and accepted by the IRS in February 2008, resulted in a 2008 net earnings benefit of approximately $39.4 million, including interest, due to the recognition of previously unrecognized tax benefits. The statute of limitations for these years has expired.

In April 2008, the IRS completed its examination of the federal income tax returns filed for years 2003 and 2004. In its examination report, the IRS did not approve our refund claim to change the original federal income tax characterization of the loss we incurred in 2004 on the sale of Protection One, Inc. (Protection One) from a capital loss to an ordinary loss. The characterization of the loss as capital or ordinary affects our ability to carryback and carryforward the loss to tax years in which the loss can be utilized. In June 2008, we filed a protest with the IRS Office of Appeals to pursue the re-characterization of the loss. In November 2008, we reached a tentative settlement with the IRS Office of Appeals (IRS Appeals Settlement) on the amount of the net capital loss and net operating loss carryforwards as of the end of December 31, 2004. This tentative settlement was subject to review by the Joint Committee on Taxation of the U.S. Congress. On December 22, 2008, we were notified that the Joint Committee on Taxation questioned the appropriateness of the settlement. We responded to the Joint Committee on Taxation's questions and submitted our response on December 29, 2008. On January 14, 2009, the IRS notified us that the Joint Committee on Taxation had approved the IRS Appeals Settlement. Given the degree of uncertainty regarding this issue we were unable to conclude that realization of the benefit was more likely than not at December 31, 2008. 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 transaction, we will pay Protection One an amount equal to 50% of the net tax benefit (less certain adjustments) that we receive from the net operating loss carryforward arising from the sale. The recognition of this previously unrecognized tax benefit in accordance with the provisions of FIN 48 will result in a net earnings benefit of approximately $32.5 million. We have extended the statute of limitations for these years until September 30, 2009.

At December 31, 2007, the amount of unrecognized tax benefits and the FIN 48 liability were $209.6 million and $70.8 million, respectively. During 2008, the FIN 48 liability decreased from $70.8 million to $39.0 million and the amount of unrecognized tax benefits decreased from $209.6 million to $92.1 million. The net decrease in FIN 48 liability is primarily attributable to the recognition of $28.7 million of unrecognized tax benefits due to the completion of the IRS examination of years 1995 through 2002. We expect a reduction of unrecognized tax benefits in the amount of $60.2 million in the first quarter of 2009 due to the IRS Appeals Settlement for years 2003 and 2004. We do not expect any other significant increases or decreases to the liability for unrecognized tax benefits within the next 12 months. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2008	2007
	(In Thousands)	
FIN 48 liability at January 1	$ 70,833	$ 50,211
Additions based on tax positions related to the current year	4,576	21,660
Additions for tax positions of prior years	—	5,197
Reductions for tax positions of prior years	(3,639)	—
Settlements	(32,790)	(6,235)
FIN 48 liability at December 31, 2008	38,980	70,833
Unrecognized tax benefits related to amended returns filed in 2007	53,092	138,778
Unrecognized tax benefits at December 31	$ 92,072	$ 209,611

The amounts of unrecognized tax benefits that, if recognized, would favorably impact our effective tax rate, are $54.8 million and $172.2 million (net of tax) as of December 31, 2008 and December 31, 2007, respectively. Included in the FIN 48 liability are $1.7 million and $33.4 million (net of tax) of tax positions, which if recognized, would favorably impact our effective income tax rate as of December 31, 2008 and December 31, 2007, respectively.

Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. As of December 31, 2008, and December 31, 2007, we had $3.8 million and $13.5 million, respectively, accrued for interest on our liability related to unrecognized tax benefits. There were no penalties accrued at either December 31, 2008, or December 31, 2007.

As of December 31, 2008 and 2007, we maintained reserves of $3.5 million and $5.2 million, respectively, for probable assessments of taxes other than income taxes.

11. EMPLOYEE BENEFIT PLANS

Pension

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 the employee’s compensation during the 60 highest paid consecutive months out of 120 before retirement. Our funding policy for the pension plan is to contribute amounts sufficient to meet the minimum funding requirements under the Employee Retirement Income Security Act (ERISA) as amended by the Pension Protection Act (PPA) and the Internal Revenue Code plus additional amounts we consider appropriate. 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.

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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 rates the cost of post-retirement benefits during an employee's years of service. We fund the portion of net periodic post-retirement benefit costs included in rates.

As a co-owner of Wolf Creek, we are indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement 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.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2008	2007	2008	2007
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 578,191	$ 551,728	$ 134,135	$ 124,546
Service cost	10,102	9,641	1,446	1,548
Interest cost	35,792	32,418	7,637	7,574
Plan participants' contributions	—	—	4,162	4,164
Benefits paid	(28,459)	(28,450)	(9,639)	(11,481)
Actuarial losses (gains)	32,151	12,718	(6,541)	(5,994)
Amendments	1,461	136	2,681	13,778
Benefit obligation, end of year	$ 629,238	$ 578,191	$ 133,881	$ 134,135
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 468,188	$ 451,824	$ 61,423	$ 52,778
Actual return on plan assets	(145,962)	31,208	(14,762)	3,215
Employer contribution	15,000	11,800	11,348	12,400
Plan participants' contributions	—	—	3,996	4,030
Part D Reimbursements	—	—	1,465	814
Benefits paid	(26,695)	(26,644)	(10,666)	(11,814)
Fair value of plan assets, end of year	$ 310,531	$ 468,188	$ 52,804	$ 61,423
Funded status, end of year	$(318,707)	$(110,003)	$ (81,077)	$ (72,712)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (1,933)	$ (1,838)	$ (125)	$ (130)
Noncurrent liability	(316,774)	(108,165)	(80,952)	(72,582)
Net amount recognized	$(318,707)	$(110,003)	$ (81,077)	$ (72,712)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 324,290	$ 114,325	$ 31,648	$ 19,636
Prior service cost	10,492	11,517	14,127	12,858
Transition obligation	—	—	16,048	19,979
Net amount recognized	$ 334,782	$ 125,842	$ 61,823	$ 52,473

As of December 31,	Pension Benefits 2008	Pension Benefits 2007	Post-retirement Benefits 2008	Post-retirement Benefits 2007
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$629,238	$578,191	$ —	$ —
Accumulated benefit obligation	531,145	497,169	—	—
Fair value of plan assets	310,531	468,188	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$629,238	$578,191	$ —	$ —
Accumulated benefit obligation	531,145	497,169	—	—
Fair value of plan assets	310,531	468,188	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 133,881	$ 134,135
Fair value of plan assets	—	—	52,804	61,423
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.10%	6.25%	6.05%	6.10%
Compensation rate increase	4.00%	4.00%	—	—

We use a measurement date of December 31 for our pension and post-retirement benefit plans.

We use an interest rate yield curve to make judgments pursuant to EITF No. D-36, “Selection of Discount Rates Used for Measuring Defined Benefit Pension Obligations and Obligations of Post Retirement Benefit Plans Other Than Pensions.” The yield curve 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.

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We amortize the 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 the amortization corridor described in SFAS No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Post-retirement Benefits Other Than Pensions."

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2008	2007	2006	2008	2007	2006
	(Dollars in Thousands)					
Components of Net Periodic Cost (Benefit):						
Service cost	$ 10,102	$ 9,641	$ 9,178	$ 1,446	$ 1,548	$ 1,492
Interest cost	35,792	32,418	30,522	7,637	7,574	6,875
Expected return on plan assets	(40,332)	(38,506)	(35,939)	(4,694)	(3,827)	(2,971)
Amortization of unrecognized:						
Transition obligation, net	—	—	—	3,930	3,930	3,931
Prior service costs/(benefit)	2,550	2,545	2,892	1,412	937	(415)
Actuarial loss, net	8,415	7,864	8,759	904	1,503	2,001
Net periodic cost	$ 16,527	$ 13,962	$ 15,412	$10,635	$11,665	$10,913
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial loss/(gain)	$218,444	$ 20,017	$ —	$12,915	$ (5,431)	$ —
Amortization of actuarial loss	(8,415)	(7,864)	—	(904)	(1,503)	—
Current year prior service cost	1,461	136	—	2,681	13,778	—
Amortization of prior service cost	(2,550)	(2,545)	—	(1,412)	(937)	—
Amortization of transition obligation	—	—	—	(3,930)	(3,930)	—
Total recognized in regulatory assets	$208,940	$ 9,744	$ —	$ 9,350	$ 1,977	$ —
Total recognized in net periodic cost and regulatory assets	$225,467	$ 23,706	$ 15,412	$19,985	$13,642	$10,913
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):						
Discount rate	6.25%	5.90%	5.65%	6.10%	5.80%	5.65%
Expected long-term return on plan assets	8.50%	8.50%	8.50%	7.75%	7.75%	7.75%
Compensation rate increase	4.00%	4.00%	3.50%	—	—	—

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2009 are as follows:	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$14,261	$ 1,276
Prior service cost	2,662	1,592
Transition obligation	—	3,930
Total	$16,923	$ 6,798

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 selected 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 developed 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 benefits plan is at least actuarially equivalent to Medicare and is, thus, eligible for the federal subsidy. 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 in 2008 and $4.6 million in both 2007 and 2006. The subsidy also decreased the net periodic post-retirement benefit cost by approximately $0.5 million for 2008 and $0.6 million for both 2007 and 2006.

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

	As of December 31,	
	2008	2007
Health care cost trend rate assumed for next year	7.50%	8.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2014	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	$ 9	$ (13)
Effect on post-retirement benefit obligation	85	(203)

The asset allocation for the pension plans and the post-retirement benefit plans at the end of 2008 and 2007, and the target allocations for 2009, by asset category, are as shown in the following table.

Asset Category	Target Allocations	Plan Assets	
	2009	2008	2007
Pension Plans:			
Equity securities	62%	60%	67%
Debt securities	30%	29%	29%
Real estate	5%	7%	—
Commodities	3%	2%	—
Cash	0% – 5%	2%	4%
Total		100%	100%
Post-retirement Benefit Plans:			
Equity securities	65%	60%	60%
Debt securities	30%	32%	29%
Cash	5%	8%	11%
Total		100%	100%

We manage pension and retiree welfare plan assets in accordance with the "prudent investor" guidelines contained in the ERISA. The plan's investment strategy supports the objective of the funds, which is 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. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

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

Expected Cash Flows	Pension Benefits		Post-retirement Benefits	
	To/(From) Trust	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
	(In Millions)			
Expected contributions: 2009	$ 51.9(a)	$ 1.9	$ 12.3	$ 0.1
Expected benefit payments:				
2009	$ (26.8)	$ (1.9)	$ (7.5)	$ (0.1)
2010	(27.2)	(1.9)	(7.8)	(0.1)
2011	(27.8)	(1.9)	(8.1)	(0.1)
2012	(28.9)	(1.9)	(8.4)	(0.1)
2013	(30.5)	(1.9)	(8.7)	(0.1)
2014 – 2018	(185.4)	(8.9)	(49.9)	(0.7)

(a) Includes required contributions of $12.9 million and voluntary contributions of $39.0 million.

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 are invested at the direction of plan participants into one or more of the investment alternatives we provide under the plan. Our contributions were $6.1 million in 2008, $5.6 million in 2007 and $4.8 million in 2006.

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, 2008, awards of 3,836,430 shares of common stock had been made under the LTISA Plan. Dividend equivalents accrue on the awarded RSUs. Dividend equivalents are the right to receive cash equal to the value of dividends paid on our common stock.

Effective January 1, 2006, we adopted SFAS No. 123R, "Share-Based Payment," for stock-based compensation plans. Under SFAS No. 123R, 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 Securities and Exchange Commission (SEC) staff issued Staff Accounting Bulletin (SAB) No. 107 on Share-Based Payment to express the views of the staff regarding the interaction between SFAS No. 123R and SEC rules and regulations as well as provide staff's view on valuation of stock-based compensation arrangements for public companies. The SAB No. 107 guidance was taken into consideration with the implementation of SFAS No. 123R.

We adopted SFAS No. 123R using the modified prospective transition method. Under the modified prospective transition method, we are required to record stock-based compensation expense for all awards granted after the adoption date and for the unvested portion of previously granted awards outstanding as of the adoption date. Compensation cost related to the unvested portion of previously granted awards is based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123. Compensation cost for awards granted after the adoption date are based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Since 2002, we have used RSUs exclusively for our stock-based compensation awards. RSUs are valued in the same manner under SFAS Nos. 123 and 123R.

The table below shows compensation expense and income tax benefits related to stock-based compensation arrangements that are included in our net income.

	Twelve Months Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Compensation expense	$4,619	$5,735	$3,395
Income tax benefits related to stock-based compensation arrangements	1,830	2,281	1,350

RSU awards are grants that entitle the holder to receive shares of common stock as the awards vest. These RSU awards are defined in SFAS No. 123R 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 issued after adoption of SFAS No. 123R with only service conditions that have a graded vesting schedule will be recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for the entire award. Awards issued prior to adoption of SFAS No. 123R will continue to be recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for each separately vesting portion of the award.

During the year ended December 31, 2008, our RSU activity was as follows:

	As of December 31,					
	2008		2007		2006	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value
	(In Thousands)		(In Thousands)		(In Thousands)	
Nonvested balance, beginning of year	984.2	$ 23.11	933.4	$ 20.82	1,094.5	$ 18.54
Granted	38.7	25.46	413.8	26.76	160.3	23.91
Vested	(261.3)	28.11	(308.5)	20.53	(306.6)	14.96
Forfeited	(34.2)	35.49	(54.5)	26.79	(14.8)	21.56
Nonvested balance, end of year	727.4	20.86	984.2	23.11	933.4	20.82

Total unrecognized compensation cost related to RSU awards was $5.8 million as of December 31, 2008. We expect to recognize these costs over a remaining weighted-average period of 1.8 years. Upon adoption of SFAS No. 123R, we were required to charge $10.3 million of unearned stock compensation against additional paid-in capital. The total fair value of shares vested during the years ended December 31, 2008, 2007 and 2006, was $6.2 million, $8.3 million and $7.2 million, respectively. There were no modifications of awards during the years ended December 31, 2008, 2007 or 2006.

SFAS No. 123R requires that forfeitures be estimated over the vesting period, rather than being recognized as a reduction of compensation expense when the forfeiture actually occurs. The cumulative effect of the use of the estimated forfeiture method for prior periods upon adoption of SFAS No. 123R was not material.

RSU awards that can be settled in cash upon a change in control were reclassified from permanent equity to temporary equity upon adoption of SFAS No. 123R. As of December 31, 2008, and December 31, 2007, we had temporary equity of $3.4 million and $5.2 million, respectively, on our consolidated balance sheet. If we determine 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 23,700 outstanding options are exercisable. There were no options exercised and 53,590 options were forfeited during the year ended December 31, 2008. 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 5,283 shares of common stock for dividends in 2008, 4,214 shares in 2007 and 4,407 shares in 2006. Participants received common stock distributions of 530 shares in 2008, 505 shares in 2007 and 1,936 shares in 2006.

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.

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12. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefits

As a co-owner of Wolf Creek, KGE is indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement plans. KGE accrues its 47% of the Wolf Creek cost of pension and 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 post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2008	2007	2008	2007
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 89,846	$ 79,213	$ 8,596	$ 7,391
Effect of eliminating early measurement date	574	—	—	—
Service cost	3,421	3,436	203	234
Interest cost	5,680	4,696	517	435
Plan participants' contributions	—	—	356	294
Benefits paid	(2,135)	(1,809)	(1,182)	(509)
Actuarial losses/(gains)	2,150	2,071	362	(114)
Amendments	—	34	—	—
Curtailments, settlements and special termination benefits	—	2,205	—	865
Benefit obligation, end of year	$ 99,536	$ 89,846	$ 8,852	$ 8,596
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 54,992	$ 47,869	$ —	$ —
Effect of eliminating early measurement date	226	—	—	—
Actual return on plan assets	(14,656)	3,314	—	—
Employer contribution	6,608	5,618	—	—
Benefits paid	(1,969)	(1,809)	—	—
Fair value of plan assets, end of year	$ 45,201	$ 54,992	$ —	$ —
Funded status	$(54,335)	$(34,854)	$ (8,852)	$ (8,596)
Post-measurement date adjustments	—	1,072	—	—
Accrued post-retirement benefit costs	$(54,335)	$(33,782)	$ (8,852)	$ (8,596)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (251)	$ (168)	$ (612)	$ (632)
Noncurrent liability	(54,084)	(33,614)	(8,240)	(7,964)
Net amount recognized	$(54,335)	$(33,782)	$ (8,852)	$ (8,596)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 40,802	$ 21,120	$ 3,258	$ 3,127
Prior service cost	119	178	—	—
Transition obligation	166	227	230	288
Net amount recognized	$ 41,087	$ 21,525	$ 3,488	$ 3,415

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As of December 31,	Pension Benefits 2008	Pension Benefits 2007	Post-retirement Benefits 2008	Post-retirement Benefits 2007
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$99,536	$89,846	$ —	$ —
Accumulated benefit obligation	77,197	68,302	—	—
Fair value of plan assets	45,201	54,992	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$99,536	$89,846	$ —	$ —
Accumulated benefit obligation	77,197	68,302	—	—
Fair value of plan assets	45,201	54,992	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 8,852	$ 8,596
Fair value of plan assets	—	—	—	—
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.15%	6.15%	6.05%	6.05%
Compensation rate increase	4.00%	4.00%	—	—

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

Wolf Creek uses an interest rate yield curve to make judgments pursuant to EITF Topic No. D-36, "Selection of Discount Rates Used for Measuring Defined Benefit Pension Obligations and Obligations of Post Retirement Benefit Plans Other Than Pensions." The yield curve 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 the amortization corridor described in SFAS Nos. 87 and 106.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2008	2007	2006	2008	2007	2006
	(Dollars in Thousands)					
Components of Net Periodic Cost:						
Service cost	$ 3,421	$ 3,436	$ 3,245	$ 203	$ 234	$ 248
Interest cost	5,680	4,696	4,293	517	435	412
Expected return on plan assets	(4,709)	(4,101)	(3,428)	—	—	—
Amortization of unrecognized:						
Transition obligation, net	57	57	57	58	58	58
Prior service costs	57	57	31	—	—	—
Actuarial loss, net	1,696	1,855	1,813	231	191	196
Curtailments, settlements and special termination benefits	—	1,486	—	—	259	—
Net periodic cost	$ 6,202	$ 7,486	$ 6,011	$1,009	$1,177	$ 914
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial loss	$21,517	$ 3,578	$ —	$ 362	$ 786	$ —
Amortization of actuarial loss	(1,696)	(1,855)	—	(231)	(191)	—
Current year prior service cost	—	34	—	—	—	—
Amortization of prior service cost	(57)	(57)	—	—	—	—
Amortization of transition obligation	(57)	(57)	—	(58)	(58)	—
Total recognized in regulatory assets	$19,707	$ 1,643	$ —	$ 73	$ 537	$ —
Total recognized in net periodic cost and regulatory assets	$25,909	$ 9,129	$ 6,011	$1,082	$1,714	$ 914
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:						
Discount rate	6.15%	5.70%	5.75%	6.05%	5.80%	5.75%
Expected long-term return on plan assets	8.25%	8.25%	8.25%	—	—	—
Compensation rate increase	4.00%	3.25%	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 2009 are as follows:	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 2,387	$ 237
Prior service cost	43	—
Transition obligation	57	58
Total	$ 2,487	$ 295

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, 2008	2007
Health care cost trend rate assumed for next year	7.5%	8.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2014	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	$ (6)	$ 5
Effect on the present value of the projected benefit obligation	(36)	28

The asset allocation for the pension plans at the end of 2008 and 2007, and the target allocation for 2009, by asset category are as shown in the following table.

Asset Category	Target Allocations 2009	Plan Assets 2008	2007
Pension Plans:			
Equity securities	65%	59%	67%
Debt securities	25%	39%	28%
Real estate	5%	—	—
Commodities	5%	—	—
Cash	—	2%	5%
Total		100%	100%

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 to 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. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews.

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: 2009	$ 11.8(a)	$ 0.2	$ —	$ 0.6
Expected benefit payments:				
2009	$ (2.2)	$ (0.2)	$ —	$ (0.6)
2010	(2.4)	(0.2)	—	(0.6)
2011	(2.6)	(0.2)	—	(0.6)
2012	(2.9)	(0.2)	—	(0.6)
2013	(3.2)	(0.2)	—	(0.7)
2014 – 2018	(23.8)	(1.2)	—	(3.5)

(a) Includes required funding of $4.4 million and voluntary funding of $7.4 million.

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 contribution to the plan is deposited with a trustee and is invested at the direction of plan participants into one or more of the investment alternatives provided under the plan. KGE’s portion of expense associated with Wolf Creek’s matching contributions was $1.0 million in 2008 and $0.9 million in 2007 and 2006.

13. COMMITMENTS AND CONTINGENCIES

Purchase Orders and Contracts

As part of our ongoing operations and construction program, we have purchase orders and contracts, excluding fuel, which is discussed below under “–Purchased Power and Fuel Commitments,” that have an unexpended balance of approximately $674.0 million as of December 31, 2008, of which $270.5 million has been committed. The $270.5 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, 2008, was as follows.

	Committed Amount
	(In Thousands)
2009	$ 174,736
2010	73,310
2011	13,226
Thereafter	9,203
Total amount committed	$ 270,475

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 two-phase reduction in certain emissions. We have installed continuous monitoring and reporting equipment in order to meet these requirements.

Environmental Projects

We have identified the potential for us to make up to $1.3 billion of capital expenditures at our power plants for environmental air emissions projects during the next six years. This estimate could materially increase or decrease depending on the timing and the nature of required investments, the specific outcomes resulting from interpretation of existing regulations, new regulations, legislation and the resolution of the Environmental Protection Agency (EPA) New Source Review Investigation (NSR Investigation) and the related Department of Justice (DOJ) lawsuit described below. In addition to the capital investment, in the event we install new equipment as a result of the NSR Investigation and the related DOJ lawsuit, such equipment may cause us to incur significant increases in annual operating and maintenance expense and may reduce net production from our power plants. The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. In addition, 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.

The ECRR allows for the more timely inclusion in retail rates of capital expenditures tied directly to environmental improvements, including those required by the Clean Air Act. However, increased operating and maintenance costs, other than expenses related to production-related consumables (e.g., limestone), can be recovered only through a change in base rates following a rate review.

On February 28, 2008, we reached an agreement with the Kansas Department of Health and Environment (KDHE) to implement a plan to improve efficiency and to install new equipment to reduce regulated emissions from Jeffrey Energy Center. The projects are designed to meet requirements of the Clean Air Visibility Rule and reduce emissions over our entire generating fleet by eliminating more than 70% of SO_2 and reducing nitrous oxides between 50% and 65%.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule. Beginning in 2010, the rule caps permanently and reduces the amount of mercury that may be emitted from coal-fired power plants. However, on February 8, 2008, the U.S. District Court of Appeals for the District of Columbia vacated the Clean Air Mercury Rule. While the ultimate impact of this ruling on our operations is currently unknown, we believe that mercury emissions controls may be required in the future and that the costs to comply with these requirements may be material.

New Source Review Investigation

Under Section 114(a) of the Clean Air Act (Section 114), 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.

The EPA requested information from us under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at three coal-fired plants we operate. 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 DOJ filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. A decision in favor of the DOJ and the EPA, or a settlement prior to such a decision, if reached, could require us to update or install emissions controls at Jeffrey Energy Center. Additionally, we might 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 NSR Investigation and the related DOJ lawsuit could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery in the prices we are allowed to charge our customers. If, however, a penalty is assessed against us, the penalty could be material and may not be recovered in rates. We are not able to estimate the possible loss or range of loss at this time.

FERC Investigation

We are responding to a preliminary investigation by FERC of our use of transmission service within the Southwest Power Pool (SPP) in 2007 and 2006. While we believe that our use of transmission service was in compliance with FERC orders and SPP tariffs, we are unable to predict the outcome of this investigation or its impact on our consolidated financial statements.

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 in 1994 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 the 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 and dismantlement study with the KCC every three years. The next review is scheduled to occur in 2009.

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” 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. The actual nuclear decommissioning costs may vary from the estimates because of changes in regulations, technologies and changes in costs for labor, materials and equipment.

Electric rates charged to customers provide for recovery of these nuclear decommissioning costs over the life of Wolf Creek, which is through 2045. The NRC requires that funds to meet its nuclear decommissioning funding assurance requirement be in our nuclear decommissioning fund by the time our operating license expires in 2045. We believe that the KCC approved funding level will also be sufficient to meet the NRC minimum financial assurance requirement. Our consolidated statements of income would be materially adversely affected if we were not allowed to recover in utility rates the full amount of the funding requirement.

We recovered in rates and deposited in an external trust fund for nuclear decommissioning approximately $2.9 million in 2008 and 2007 and $3.9 million in 2006. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $85.6 million as of December 31, 2008, and $122.3 million as of December 31, 2007. During 2008, the value of these financial assets declined significantly. As a result, we will likely have to contribute additional amounts to the nuclear decommissioning fund. We expect to collect those amounts from our customers.

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. As required by federal law, the Wolf Creek co-owners entered into a standard contract with the DOE in 1984 in which the DOE promised to begin accepting from commercial nuclear power plants their used nuclear fuel for disposal beginning in early 1998. In return, 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 was $3.5 million in 2008, $4.4 million in 2007 and $4.1 million in 2006 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers. We include these disposal costs in fuel and purchased power expenses.

In 2002, the Yucca Mountain site in Nevada was approved for the development of a nuclear waste repository for the disposal of spent nuclear fuel and high-level nuclear waste from the nation’s defense activities. This action allows the DOE to apply to the NRC to license the project. On June 3, 2008, the DOE submitted a license application to the NRC seeking authorization to construct the nuclear waste repository at the Yucca Mountain site. The opening of the Yucca Mountain site has been delayed many times and could be delayed further due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel. Wolf Creek has on-site temporary storage for spent nuclear fuel expected to be generated by Wolf Creek through 2025.

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 was 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. Under this retrospective assessment program, the owners of WCNOC 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 or 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 $23.3 million (our share is $11.0 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 through rates, would have a material adverse effect on our consolidated financial statements.

Purchased Power and Fuel Commitments

To supply a portion of the fuel requirements for our generating plants, we have entered into various commitments to obtain nuclear fuel and coal. Some of these contracts contain provisions for price escalation and minimum purchase commitments. As of December 31, 2008, our share of Wolf Creek's nuclear fuel commitments were approximately $56.9 million for uranium concentrates expiring in 2016, $8.3 million for conversion expiring in 2016, $147.2 million for enrichment expiring in 2024 and $50.8 million for fabrication expiring in 2024.

As of December 31, 2008, our coal and coal transportation contract commitments in 2008 dollars under the remaining terms of the contracts were approximately $1.5 billion. The two largest contracts expire in 2013 and 2020, with the remaining contracts expiring at various times prior to 2013.

As of December 31, 2008, our natural gas transportation commitments in 2008 dollars under the remaining terms of the contracts were approximately $196.5 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2028.

During 2007, we entered into power purchase 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 $19.5 million. One of the facilities was placed in service in December 2008 and we expect the other one to be placed in service in early 2009.

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14. ASSET RETIREMENT OBLIGATIONS

Legal Liability

In accordance with SFAS No. 143, “Accounting for Asset Retirement Obligations” and FIN 47, “Accounting for Conditional Asset Retirement Obligations”, 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 asset retirement obligations for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71.

We initially recorded asset retirement obligations 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 asset retirement obligations included on our consolidated balance sheets in long-term liabilities.

	As of December 31,	
	2008	2007
	(In Thousands)	
Beginning asset retirement obligations	$ 88,711	$ 84,192
Liabilities incurred	1,143	85
Liabilities settled	(195)	(987)
Accretion expense	5,424	5,421
Ending asset retirement obligations	$ 95,083	$ 88,711

We have adopted the provisions of FIN 47, which clarifies the meaning of the term “conditional asset retirement obligation” as used in SFAS No. 143. Conditional asset retirement obligation 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 the conditional asset retirement obligations that are within the scope of FIN 47 to 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 rates the costs to dispose of utility plant assets that do not represent legal retirement obligations. As of December 31, 2008 and 2007, we had $50.1 million and $25.2 million, respectively, in amounts collected, but unspent, for removal costs classified as a regulatory liability. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in rates 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, 2008, we had accrued liabilities of $74.9 million for compensation not yet paid to them and $6.8 million 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 statements.

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 statements.

See also Note 13, "Commitments and Contingencies."

16. GUARDIAN INTERNATIONAL PREFERRED STOCK

On March 6, 2006, Guardian International, Inc. (Guardian) was acquired by Devcon International Corporation in a merger. In connection with this merger, we received approximately $23.2 million for 15,214 shares of Guardian Series D preferred stock and 8,000 shares of Guardian Series E preferred stock held of record by us. We recognized a gain of approximately $0.3 million as a result of this transaction. A majority of these shares were beneficially owned by the two executive officers referred to in Note 15, "Legal Proceedings." The ownership of the shares they beneficially owned, as well as related dividends, and now the cash received for the shares, is disputed and is the subject of the arbitration proceeding discussed in Note 15, "Legal Proceedings." As a result of this transaction, we no longer hold any Guardian securities.

17. 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, 2005	214,363	86,835,371
Issuance of common stock	—	559,515
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

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. As of December 31, 2008, we had 108,311,135 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 2008, a total of 592,772 shares were issued by Westar Energy through the DSPP and other stock based plans operated under the 1996 LTISA Plan. As of December 31, 2008, a total of 3,862,038 shares were available under the DSPP registration statement.

Common Stock Issuance

On May 29, 2008, we entered into an underwriting agreement relating to the offer and sale of 6.0 million shares of the company's common stock. On June 4, 2008, we 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, we entered into a forward sale agreement with a bank, as forward purchaser, relating to 8.2 million shares of our common stock. The forward sale agreement provides for the sale of our 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 our 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, we delivered 3.1 million newly issued shares of our 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, we delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. On June 30, 2008, we completed the forward sale agreement by delivering 3.0 million shares and receiving proceeds of $73.0 million.

On August 24, 2007, we entered into a Sales Agency Financing Agreement with a bank. Under the terms of the agreement, we may offer and sell shares of our 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. We will pay the bank a commission equal to 1% of the sales price of all shares sold under the agreement. During 2007 we 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 we 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.

On April 12, 2007, we entered into an earlier Sales Agency Financing Agreement with the same bank. As of July 12, 2007, we had sold 3.7 million shares of the company's common stock for $100.0 million pursuant to the agreement. We received $99.0 million in proceeds net of a commission.

We used the proceeds of stock issued to repay borrowings under Westar Energy's 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, 2008.

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, 2008, 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.

18. 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 1 to 21 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:		
2006	$ 18,069	$ 32,107
2007	18,069	35,267
2008	18,069	38,870
Future commitments:		
2009	$ 32,964	$ 49,602
2010	33,041	47,283
2011	33,122	46,386
2012	33,209	48,387
2013	33,350	44,900
Thereafter	256,125	287,699
Total future commitments	$ 421,811	$ 524,257

(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 criteria in SFAS No. 13, "Accounting for Leases." 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 one to 14 years depending on the type of vehicle. Computer equipment has a lease term of two to four years.

On April 1, 2007, we completed the purchase of Aquila, Inc.'s (Aquila) 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 recorded a capital lease of $118.5 million.

Assets recorded under capital leases are listed below.

	December 31, 2008	December 31, 2007
	(In Thousands)	
Vehicles	$ 24,443	$ 27,132
Computer equipment and software	6,133	5,212
Jeffrey Energy Center 8% interest	118,538	118,538
Accumulated amortization	(22,526)	(20,576)
Total capital leases	$126,588	$130,306

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,	Total Capital Leases
	(In Thousands)
2009	$ 17,443
2010	15,930
2011	15,967
2012	11,920
2013	7,638
Thereafter	119,239
	188,137
Amounts representing imputed interest	(61,073)
Present value of net minimum lease payments under capital leases	127,064
Less current portion	9,155
Total long-term obligation under capital leases	$ 117,909

19. DISCONTINUED OPERATIONS — Sale of Protection One and Protection One Europe

In 2006, we received proceeds of $1.2 million that was released from an escrow account arising from the sale of Protection One Europe, a security business we sold on June 30, 2003.

20. 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.

2008	First (a)	Second (b)	Third	Fourth (c)
	(In Thousands, Except Per Share Amounts)			
Sales (d)	$406,827	$ 451,219	$574,853	$ 406,097
Net income (d)	61,136	5,845	88,285	22,874
Earnings available for common stock (d)	60,894	5,603	88,043	22,632
Per Share Data (d):				
Basic:				
Earnings available	$ 0.63	$ 0.06	$ 0.81	$ 0.21
Diluted:				
Earnings available	$ 0.62	$ 0.06	$ 0.81	$ 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 earnings available for common stock decreased due 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 incentives 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.

2007	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Sales (a)	$ 370,306	$ 415,178	$ 548,496	$ 392,854
Net income (a)	30,175	32,708	91,706	13,765
Earnings available for common stock (a)	29,933	32,466	91,464	13,523
Per Share Data (a):				
Basic:				
Earnings available	$ 0.34	$ 0.36	$ 0.99	$ 0.15
Diluted:				
Earnings available	$ 0.34	$ 0.36	$ 0.99	$ 0.14
Cash dividend declared per common share	$ 0.27	$ 0.27	$ 0.27	$ 0.27
Market price per common share:				
High	$ 28.54	$ 28.57	$ 26.44	$ 26.83
Low	$ 25.23	$ 23.81	$ 22.84	$ 24.29

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Under the supervision and with the participation of our management, including our chief executive officer and our chief financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934. These controls and procedures are designed to ensure that material information relating to the company and its subsidiaries is communicated to the chief executive officer and the chief financial officer. Based on that evaluation, our chief executive officer and our chief financial officer concluded that, as of December 31, 2008, our disclosure controls and procedures were effective at a reasonable assurance level to ensure that information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to the chief executive officer and the chief financial officer, and recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Act is accumulated and communicated to the issuer's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting during the fourth quarter ended December 31, 2008, 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 2009 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (the 2009 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 2009 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 2009 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 2009 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 2009 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

Not applicable.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by Item 14 will be set forth in our 2009 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, 2008 and 2007
Consolidated Statements of Income for the years ended December 31, 2008, 2007 and 2006
Consolidated Statements of Comprehensive Income for the years ended December 31, 2008, 2007 and 2006
Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006
Consolidated Statements of Shareholders’ Equity for the years ended December 31, 2008, 2007 and 2006
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

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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

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4(a)	-Mortgage and Deed of Trust dated July 1, 1939 between Westar Energy, Inc. and Harris Trust and Savings Bank, Trustee (filed as Exhibit 4(a) to Registration Statement No. 33-21739)	I
4(b)	-First and Second Supplemental Indentures dated July 1, 1939 and April 1, 1949, respectively (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(c)	-Sixth Supplemental Indenture dated October 4, 1951 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(d)	-Fourteenth Supplemental Indenture dated May 1, 1976 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(e)	-Twenty-Eighth Supplemental Indenture dated July 1, 1992 (filed as Exhibit 4(o) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(f)	-Twenty-Ninth Supplemental Indenture dated August 20, 1992 (filed as Exhibit 4(p) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(g)	-Thirtieth Supplemental Indenture dated February 1, 1993 (filed as Exhibit 4(q) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(h)	-Thirty-First Supplemental Indenture dated April 15, 1993 (filed as Exhibit 4(r) to the Form S-3 Registration Statement No. 33-50069 filed on August 24, 1993)	I
4(i)	-Thirty-Second Supplemental Indenture dated April 15, 1994 (filed as Exhibit 4(s) to the Form 10-K for the period ended December 31, 1994 filed on March 30, 1995)	I
4(j)	-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

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4(w)	-Fortieth Supplemental Indenture dated May 15, 2007, between Westar Energy, Inc. and The Bank of New York Trust Company, N.A. (as successor to Harris Trust and Savings Bank) to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.16 to the Form 8-K filed on May 16, 2007)	I
4(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
	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 Change of Control Agreement with officers of Westar Energy, Inc. (filed as Exhibit 10(o) to the Form 10-K for the period ended December 31, 2000 filed on April 2, 2001)*	I
10(n)	-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(o)	-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(p)	-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(q)	-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(r)	-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(s)	-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(t)	-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(u)	-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(v)	-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(w)	-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(x)	-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(y)	-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(z)	-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(aa)	-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 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)	I
10(ab)	-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

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10(ac)	-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(ad)	-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(ae)	-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(af)	-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(ag)	-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(ah)	-Deferral Election Form of William B. Moore (filed as Exhibit 10.2 to the Form 8-K filed on December 29, 2004)*	I
10(ai)	-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(aj)	-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(ak)	-Form of Change in Control Agreement (filed as Exhibit 10.1 to the Form 8-K filed on January 26, 2006)*	I
10(al)	-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(am)	-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(an)	-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(ao)	-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(ap)	-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(aq)	-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
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)	-Westar Energy, Inc. Form of Restricted Share Units Award (filed as Exhibit 99.1 to the Form 8-K filed on December 19, 2006)	I
99(k)	-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)	
99(l)	-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)	

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, 2006				
Allowances deducted from assets for doubtful accounts	$ 5,233	$ 5,091	$ (4,067)	$ 6,257
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

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

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SIGNATURE

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

			WESTAR ENERGY, INC.
Date:	February 27, 2009	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 27, 2009
/s/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 27, 2009
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 27, 2009
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 27, 2009
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 27, 2009
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 27, 2009
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 27, 2009
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	February 27, 2009
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 27, 2009
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	February 27, 2009
/s/ JOHN C. NETTELS, JR. (John C. Nettels, Jr.)	Director	February 27, 2009

Exhibit 12(a)

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

	Year Ended December 31,				
	2008	2007	2006	2005	2004
Earnings from continuing operations (a)	$ 182,139	$ 232,224	$ 221,715	$ 195,485	$ 133,542
Fixed Charges:					
Interest expense	126,986	116,973	102,703	111,735	143,953
Interest on corporate-owned life insurance borrowings	58,207	55,164	52,234	51,058	50,429
Interest applicable to rentals	23,227	22,713	21,959	23,324	21,377
Total Fixed Charges (b)	208,420	194,850	176,896	186,117	215,759
Distributed income of equity investees	—	—	—	—	—
Preferred Dividend Requirements:					
Preferred dividends	970	970	970	970	970
Income tax required	22	368	330	435	324
Total Preferred Dividend Requirements (c)	992	1,338	1,300	1,405	1,294
Total Fixed Charges and Preferred Dividend Requirements	209,412	196,188	178,196	187,522	217,053
Earnings (d)	$ 390,559	$ 427,074	$ 398,611	$ 381,602	$ 349,301
Ratio of Earnings to Fixed Charges	1.87	2.19	2.25	2.05	1.62
Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements	1.87	2.18	2.24	2.03	1.61

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

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

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

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

Exhibit 21

WESTAR ENERGY, INC.
Subsidiaries of the Registrant

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

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

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-141899 on Form S-3, and Registration Statement Nos. 333-93355, 333-70891, 333-13229, 333-151104, 333-149706 and 333-75395 on Form S-8 of our reports dated February 26, 2009 (which report on the financial statements expresses an unqualified opinion and includes an explanatory paragraph regarding the adoption of a new accounting standard), relating to the financial statements and financial statement schedule of Westar Energy, Inc. and subsidiaries, and the effectiveness of Westar Energy, Inc.'s internal control over financial reporting, appearing in this Annual Report on Form 10-K of Westar Energy, Inc. for the year ended December 31, 2008.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 26, 2009

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

I, William B. Moore, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2008, of Westar Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the company as of, and for, the periods presented in this report;
4. The company's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the company and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the company's internal control over financial reporting that occurred during the company's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and
5. The company's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect company's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2009

By: /s/ William B. Moore
William B. Moore
Director, President and Chief Executive Officer
Westar Energy, Inc.
(Principal Executive Officer)

Exhibit 31(b)

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

I, Mark A. Ruelle, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2008, of Westar Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the company as of, and for, the periods presented in this report;
4. The company's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the company and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the company's internal control over financial reporting that occurred during the company's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and
5. The company's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect company's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2009

By: /s/ Mark A. Ruelle
Mark A. Ruelle,
Executive Vice President and Chief Financial Officer
Westar Energy, Inc.
(Principal Accounting Officer)

Exhibit 32

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

In connection with the Annual Report of Westar Energy, Inc. (the Company) on Form 10-K for the year ended December 31, 2008 (the Report), which this certification accompanies, William B. Moore, in my capacity as Director, Chief Executive Officer and President of the Company, and Mark A. Ruelle, in my capacity as Executive Vice President and Chief Financial Officer of the Company, certify that the Report fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date:	February 27, 2009	By:	/s/ William B. Moore
			William B. Moore Director, President and Chief Executive Officer
Date:	February 27, 2009	By:	/s/ Mark A. Ruelle
			Mark A. Ruelle, Executive Vice President and Chief Financial Officer