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

FORM 10-K

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

For the fiscal year ended December 31, 2005

OR

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

For the transition period from ______ to ______

Commission File Number 1-3523

WESTAR ENERGY, INC.
(Exact name of registrant as specified in its charter)

Kansas	**48-0290150**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

818 South Kansas Avenue, Topeka, Kansas 66612 (785) 575-6300
(Address, including Zip code and telephone number, including area code, of registrant's principal executive offices)

Securities registered pursuant to section 12(b) of the Act:

Common Stock, par value $5.00 per share	**New York Stock Exchange**
(Title of each class)	**(Name of each exchange on which registered)**

Securities registered pursuant to section 12(g) of the Act:

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 ☒ 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 ☒

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 ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Act). Check one:

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $2,081,879,276 at June 30, 2005.

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	**86,954,951 shares**
(Class)	**(Outstanding at February 28, 2006)**

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 2006 Annual Meeting of Shareholders	Part III (Item 10 through Item 14) (Portions of Item 10 are not incorporated by reference and are provided herein)

TABLE OF CONTENTS

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:

- capital expenditures,
- earnings,
- 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,
- nuclear operations, and
- the overall economy of our service area.

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

- electric utility deregulation or re-regulation,
- regulated and competitive markets,
- ongoing municipal, state and federal activities,
- economic and capital market conditions,
- changes in accounting requirements and other accounting matters,
- changing weather,
- the outcome of the Federal Energy Regulatory Commission transmission formula rate application filed on May 2, 2005,
- rates, cost recoveries and other regulatory matters,
- the impact of changes and downturns in the energy industry and the market for trading wholesale electricity,
- the outcome of the notice of violation received on January 22, 2004 from the Environmental Protection Agency and other environmental matters,
- political, legislative, judicial and regulatory developments,
- the impact of the purported employee class action lawsuits filed against us,
- the impact of our potential liability to David C. Wittig and Douglas T. Lake for unpaid compensation and benefits and the impact of claims they have made against us related to the termination of their employment and the publication of the report of the special committee of the board of directors,
- the impact of changes in interest rates,
- changes in, and the discount rate assumptions used for, pension and other post-retirement and post-employment benefit liability calculations, as well as actual and assumed investment returns on pension plan assets,
- the impact of changing interest rates and other assumptions regarding our Wolf Creek Generating Station decommissioning obligation,
- regulatory requirements for utility service reliability,
- homeland security considerations,
- coal, natural gas, oil and wholesale electricity prices,
- availability and timely provision of our coal supply, 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.

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 660,000 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 DURING 2005

Overview

- We filed applications with the Kansas Corporation Commission (KCC) on May 2, 2005 for an increase in our retail electric rates. Effective January 2006, the KCC authorized changes in our rates that left our rates virtually unchanged and approved various other changes in our rate structure. See "–Retail Rate Review" below for additional information.
- We incurred approximately $38.1 million in maintenance costs and capital expenditures to restore our electric distribution system as a result of a severe ice storm that occurred in January 2005. As allowed by the December 28, 2005 KCC Order, we will begin to recover these costs in rates in 2006.
- Coal delivery issues caused our coal inventory levels to decline significantly below desired levels, which required us to rely on more expensive sources of power to meet our customers' energy needs.
- Wholesale sales volumes have declined and could continue to decline due to the cost and availability of fuel and growing demands of our retail customers.
- The cost of fuel and purchased power has increased significantly. Higher fuel and purchased power costs, unit outages, and operating constraints, such as our efforts to conserve coal, increased our total fuel and purchased power costs. However, we expect the effect of these increased costs to be mitigated with the February 2006 implementation of a retail energy cost adjustment (RECA) as discussed below.

Retail Rate Review

December 28, 2005 KCC Order

In accordance with a 2003 KCC order, we filed applications with the KCC on May 2, 2005 to review our rates. We requested an increase in our retail electric rates and the adoption of other practices under the KCC's jurisdiction. While the KCC ordered a net increase in our base rates of $38.8 million annually, the increase is substantially offset by the requirement that we credit to retail customers a rolling three-year average of the margins we realize from our market-based wholesale sales. Other significant changes approved by the KCC are the RECA, an environmental cost recovery rider (ECRR), the separation of transmission delivery charges, an increase in annual depreciation expense, an extended recovery period for costs being recovered for which no return is provided and the recovery of various costs that have been incurred and deferred as regulatory assets.

Retail Energy Cost Adjustment: The RECA allows us to recover the actual cost of fuel consumed in producing electricity and the cost of purchased power. The adjustment is based on the actual cost of fuel and purchased power less margins from market-based wholesale sales. We have contracts with certain large industrial customers, the terms of which do not provide for the separate billing of fuel costs. Fuel costs for these customers will continue to be recovered through the rates specified in each of these contracts. These customers represented approximately 8% of our total retail sales volumes for 2005.

Wholesale Sales Margins: The terms of the RECA require that we include, as a credit to recoverable fuel costs, an amount based on the average of the margins realized from market-based wholesale sales during the immediately prior three-year period. In any period we are unable to realize market-based wholesale sales margins at least equal to the amount of the credit, our financial results would be adversely affected. In the short-term, our generating capacity is fixed while the load requirements of our customers change constantly. When our generating capacity is not needed to serve our customers, we attempt to seek out wholesale sales of energy at prices in excess of the costs of production. We are likely to face the prospect of decreasing margins as the energy demands of our retail customers increase, which may result in crediting to retail customers an amount that would exceed the margins realized in the current period.

Environmental Cost Recovery Rider: The ECRR allows for the timely inclusion in rates, without requiring a full rate review, of the capital expenditures made to upgrade our equipment to meet stricter environmental standards required by the Clean Air Act. Prior to collection through rates, the KCC will review any environmental expenditures to be considered for recovery under the ECRR. Any increased operating and maintenance costs that result from updating or adding environmental equipment cannot be recovered through the ECRR. These costs would be addressed in future rate reviews.

Transmission Delivery Charge: The December 28, 2005 KCC Order allows us to separate our transmission costs from our base rates charged to retail customers. This allows us to implement a formula transmission rate that provides for annual adjustments to reflect changes in our transmission costs, which provides for adjustment on a more timely basis. These rates were proposed in an application filed with the Federal Energy Regulatory Commission (FERC) on May 2, 2005 and became effective on December 1, 2005, subject to refund upon review and approval by FERC.

Depreciation Rates: The December 28, 2005 KCC Order authorized an annual increase in the recovery of depreciation expense of approximately $27.6 million. The approved change in depreciation rates allows for the inclusion of net salvage costs, which include an estimate for the cost of dismantlement of plant facilities.

Disallowed Plant Costs: In 1985, the 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 original depreciable life of Wolf Creek, or through 2025, but disallowed any return on these costs. In its December 28, 2005 order, the KCC extended the recovery period to correspond to Wolf Creek's new estimated depreciable life. KGE recognized a loss of $10.4 million in the fourth quarter of 2005 as a result of the decrease in the present value of amounts to be received due to the extension of the recovery period.

Other Regulatory Assets: The December 28, 2005 KCC Order also approved for recovery approximately $50.3 million of deferred maintenance costs associated with restoring utility service to our customers stemming from damage to our lines and equipment in the ice storms that occurred in 2002 and 2005 and various other expenses that are relatively small in relation to the total regulatory asset balance.

Table of Contents

OPERATIONS

General

Westar Energy supplies electric energy at retail to approximately 355,000 customers in central and northeast Kansas and KGE supplies electric energy at retail to approximately 305,000 customers in south-central and southeastern Kansas. We also supply electric energy at wholesale to the electric distribution systems of 48 cities in Kansas and four electric cooperatives that serve rural areas of Kansas. We have contracts for the sale, purchase or exchange of wholesale electricity with other utilities. In addition, we engage in energy marketing and purchase and sell wholesale electricity in areas outside our retail service territory.

As discussed above, the December 28, 2005 KCC Order will allow us to recover the actual cost of fuel consumed in producing electricity and the cost of purchased power effective with the implementation of the new rates in February 2006. This applies to all fuel types we use and to our purchased power. The KCC will review our fuel and power purchasing practices on an annual basis to ensure that these expenses were incurred prudently. If it were determined that any portion of our fuel and purchased power expenses were incurred imprudently, these costs could be disallowed by the KCC.

Generation Capacity

We have 5,851 megawatts (MW) of generating capacity, of which 2,604 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	3,299.0	56.4
Nuclear	548.0	9.4
Natural gas or oil	1,920.0	32.8
Diesel fuel	83.0	1.4
Wind	1.2	—
Total	5,851.2	100.0

Our aggregate 2005 peak system net load of 4,549 MW occurred on July 25, 2005. Our net generating capacity, combined with firm capacity purchases and sales, provided a capacity margin of approximately 20% above system peak responsibility at the time of our 2005 peak system net load.

We have agreed to provide generating capacity to other utilities as set forth below.

Utility	Capacity (MW)	Period Ending
Midwest Energy, Inc.	25	May 2007
Midwest Energy, Inc.	130	May 2008
Midwest Energy, Inc.	125	May 2010
Empire District Electric Company	162	May 2010
Oklahoma Municipal Power Authority	60	December 2013
McPherson Board of Public Utilities (McPherson)	(a)	May 2027

(a) We provide base load capacity to McPherson; and McPherson provides peaking capacity to us. During 2005, we provided approximately 77 MW to, and received approximately 180 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. The quantity of heat consumed during the generation of electricity is measured in millions of Btu (MMBtu).

Based on MMBtus, our 2005 actual fuel mix was 79% coal, 14% nuclear and 7% natural gas, oil and diesel fuel. We expect a similar fuel mix in 2006. 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 2,210 MW, of which we own an 84% share, or 1,857 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 over the scheduled annual minimum is subject to renegotiation every five years to provide an adjusted price for the ensuing five years that reflects then current market prices. The next re-pricing is scheduled for 2008.

We transport coal from Wyoming under a long-term rail transportation contract with the Burlington Northern Santa Fe (BNSF) and Union Pacific railroads. 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 2005 was approximately $1.32 per MMBtu, or $22.01 per ton.

La Cygne Generating Station: The two coal-fired units at La Cygne Generating Station (La Cygne) have an aggregate generating capacity of 1,398 MW, of which we own or lease a 50% share, or 699 MW. La Cygne unit 1 uses a blended fuel mix containing approximately 85% PRB coal and 15% Kansas/Missouri coal. 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. The La Cygne unit 1 Kansas/Missouri coal is purchased from time to time from local Kansas and Missouri producers.

During 2005, the average delivered cost of all coal burned at La Cygne unit 1 was approximately $1.05 per MMBtu, or $17.91 per ton. The average delivered cost of coal burned at La Cygne unit 2 was approximately $0.88 per MMBtu, or $14.76 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 743 MW. During 2005, we began purchasing coal under a contract with Arch Coal, Inc. This contract extends through 2009. This contract is expected to provide 100% of the coal requirement for these energy centers through 2007 and 70% of the coal requirements during 2008 and 2009. Approximately 30% of the coal to be delivered under this contract is priced within a specified range of spot market prices for 2006 and 2007 and approximately 43% of the coal to be delivered under this contract is priced within a specified range of spot market prices in 2008 and 2009.

We transport coal from Wyoming using the BNSF railroad under a contract that expires in December 2006. We anticipate entering into a similar contract when the current contract expires. We expect increases in the cost of transporting coal due to higher prices.

During 2005, the average delivered cost of all coal burned in the Lawrence units was approximately $1.09 per MMBtu, or $19.22 per ton. The average delivered cost of all coal burned in the Tecumseh units was approximately $1.13 per MMBtu, or $20.03 per ton.

Natural Gas

We use natural gas either as a primary fuel or as a start-up and/or secondary fuel, depending on market prices, at our Gordon Evans, Murray Gill, Neosho, Abilene and Hutchinson Energy Centers, in the gas turbine units at Tecumseh Energy Center and in the combined cycle units at the State Line facility. We also use natural gas as a supplemental fuel in the coal-fired units at the Lawrence and Tecumseh Energy Centers. We purchase natural gas in the spot market, which supplies our facilities with natural gas to meet our operational needs. During 2005, we purchased 7.9 million MMBtu of natural gas on the spot market for a total cost of $67.2 million. Natural gas accounted for approximately 3% of our total MMBtu of fuel burned during 2005 and approximately 16% of our total fuel expense. From time to time, we may purchase derivative contracts or use other fuel types 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. This contract expires April 30, 2006. We are currently renegotiating this contract. We meet a portion of our natural gas transportation requirements for the Gordon Evans, Murray Gill, Neosho, Lawrence and Tecumseh Energy Centers through firm natural gas transportation capacity agreements with Southern Star Central Pipeline. We meet all of the natural gas transportation requirements for the State Line facility through a firm natural gas transportation agreement with Southern Star Central Pipeline. The firm transportation agreements that serve the Gordon Evans, Murray Gill, Lawrence and Tecumseh Energy Centers extend through April 1, 2010. The agreement for the Neosho and State Line facilities extends through June 1, 2016.

Oil

Once started with natural gas, most of the steam units at our Gordon Evans, Murray Gill, Neosho and Hutchinson Energy Centers have the capability to burn oil or natural gas. We use oil as an alternate fuel when economical or when interruptions to natural gas supply make it necessary. During 2005 oil was more economical than natural gas, therefore, we used oil as the primary fuel in these generating facilities for most of 2005. During 2005, we burned 11.5 million MMBtu of oil at a total cost of $57.3 million. Oil accounted for approximately 4% of our total MMBtu of fuel burned during 2005 and approximately 13% of our total fuel expense. From time to time, we may purchase derivative contracts or use other fuel types in an effort to mitigate the effect of high oil prices. For additional information on our exposure to commodity price risks, see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

Oil is also used as a start-up fuel at some of our generating stations, as a primary fuel in the Hutchinson No. 4 combustion turbine and in our diesel generators. We purchase oil in the spot market and under contract. 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.

Because oil does not burn as cleanly as natural gas, our ability to use as much oil in the future could be constrained by environmental regulations. See “–Environmental Matters” below for additional information.

Other Fuel Matters

The table below provides the weighted average cost of fuel that we have used, including transportation costs.

	2005	2004	2003
Per MMBtu:			
Nuclear	$ 0.42	$ 0.39	$ 0.39
Coal	1.20	1.11	1.07
Natural gas	8.53	6.62	4.83
Oil	4.97	3.77	3.24
Per MWh Generation:			
Nuclear	$ 4.34	$ 4.05	$ 4.08
Coal	13.20	12.27	11.90
Natural gas/oil	68.19	52.98	40.04
All generating stations	15.36	12.64	12.08

Purchased Power

At times, we purchase power to meet the energy needs of our customers. Factors that cause us to purchase power to serve our customers include outages at our generating plants, prices for wholesale energy, extreme weather conditions and other factors. If we were unable to generate an adequate supply of electricity to serve our customers, we would typically purchase power in the wholesale market. Transmission constraints may keep us from purchasing power in which case we would have to implement curtailment or interruption procedures as permitted by our tariffs and terms and conditions of service. Purchased power for the year ended December 31, 2005 comprised approximately 8% of our total operating expenses. The weighted average cost of purchased power was $59.05 per MWh in 2005, $54.10 per MWh in 2004 and $52.33 per MWh in 2003.

Energy Marketing Activities

We engage in both financial and physical trading to increase profits, manage our commodity price risk and enhance system reliability. We trade electricity, coal, natural gas and oil. We use a variety of financial instruments, including forward contracts, options and swaps, and we trade energy commodity contracts.

Nuclear Generation

General

Wolf Creek is a 1,166 MW nuclear power plant located near Burlington, Kansas. Wolf Creek began operation in 1985. KGE owns a 47% interest in Wolf Creek, or 548 MW, which represents 9% of our total generating capacity. KCPL owns a 47% interest in Wolf Creek and a 6% interest is owned by Kansas Electric Power Cooperative, Inc. (KEPCo). The co-owners pay operating costs equal to their percentage ownership in Wolf Creek.

Fuel Supply

We have 100% of the uranium and conversion services needed to operate Wolf Creek through September 2009 under contract. We also have 100% of the enrichment services required to operate Wolf Creek through March 2008 under contract. Letters of intent have been issued with suppliers for a majority of Wolf Creek's uranium, conversion and enrichment requirements extending through 2017. Fabrication requirements are under contract through 2024.

All uranium, uranium conversion and uranium enrichment arrangements, as well as the fabrication agreement, have been entered into in the ordinary course of business, and we believe Wolf Creek is not substantially dependent on these agreements. However, contraction and consolidation among suppliers of these commodities and services, coupled with increasing worldwide demand and past inventory draw-downs, have introduced uncertainty as to the ability to replace, if necessary, some of these contracts in the event of a protracted supply disruption. We believe this potential problem is common in the nuclear industry. Accordingly, in the event the affected contracts were required to be replaced, we believe that the industry and government would arrive at a solution to reduce disruption of the nuclear industry's operations.

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 $3.8 million in 2005, $4.3 million in 2004 and $3.8 million in 2003 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation produced. We include these costs in operating 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 Nuclear Regulatory Commission (NRC) to license the project. Currently, the DOE has not defined a schedule for submitting a license application. 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 the expiration of its operating license in 2025.

Wolf Creek disposes of all classes of its low-level radioactive waste at existing third-party repositories. Should disposal capability become unavailable, 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 causing a new disposal facility to be developed within one of the member states. The Central States Compact Commission selected Nebraska as the host state for the disposal facility.

In December 1998, the Nebraska agencies responsible for considering the developer's license application denied the application. Most of the utilities that had provided the project's pre-construction financing and the Central States Compact Commission filed a lawsuit in federal court contending Nebraska officials acted in bad faith while handling the license application. In September 2002, the court entered a judgment of $151.4 million, about one-third of which constitutes prejudgment interest, in favor of the Central States Compact Commission and against Nebraska, finding that Nebraska had acted in bad faith in handling the license application. Following unsuccessful appeals of the decision by Nebraska, in August 2004 Nebraska and the Central States Compact Commission settled the case. In August 2005, we received $9.2 million in proceeds from the Central States Compact as a result of the settlement.

Outages

Wolf Creek operates on an 18-month refueling and maintenance outage schedule. Wolf Creek was shut down for 41 days in 2005 for its fourteenth scheduled refueling and maintenance outage. During outages at the plant, we meet our electric demand primarily with our fossil-fueled generating units and by purchasing power, depending on availability and cost. As provided by the KCC, we amortize the incremental maintenance costs incurred for planned refueling outages evenly over the unit's 18 month operating cycle. Wolf Creek is scheduled to be taken off-line in the fall of 2006 for its fifteenth refueling and maintenance outage.

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. Wolf Creek currently meets all NRC oversight objectives and receives the minimum regimen of NRC inspections. Although not expected, the NRC could impose an unscheduled plant shutdown due to security or other concerns.

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 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 KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the nuclear decommissioning study, the current-year funding and future funding. Phase two is the filing 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.

Wolf Creek filed an updated nuclear decommissioning site study with the KCC. Based on the 2005 site study of decommissioning costs, including the costs of decontamination, dismantling and site restoration, our share of such costs are estimated to be $243.3 million. This amount compares to the 2002 site study estimate for decommissioning costs of $220.0 million. The site study cost estimate represents the estimate to decommission Wolf Creek as of the site study year. The actual nuclear decommissioning costs may vary from the estimates because of changes in technology 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, as determined by the KCC for purposes of the funding schedule, will be 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 license expires in 2025. We believe that the KCC approved funding level will be sufficient to meet the NRC minimum financial assurance requirement. However, our consolidated results of operations would be materially adversely affected if we are not allowed to recover the full amount of the funding requirement.

Nuclear decommissioning costs that are recovered in rates are deposited in an external trust fund. In 2005, we expensed approximately $3.9 million for nuclear decommissioning. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $100.8 million at December 31, 2005 and $91.1 million at December 31, 2004.

Competition and Deregulation

Electric utilities have historically operated in a rate-regulated environment. FERC, the federal regulatory agency that has jurisdiction over our wholesale rates and transmission services, and other utilities have initiated steps expected to result in a more competitive environment for utility services in the wholesale market.

The 1992 Energy Policy Act began deregulating the electricity market for generation. The Energy Policy Act permitted FERC to order electric utilities to allow third parties to use their transmission systems to transport electric power to wholesale customers. In 1992, we agreed to permit third parties access to our transmission system for wholesale transactions. FERC also requires us to provide transmission services to others under terms comparable to those we provide ourselves. In December 1999, 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 open and more competitive markets in bulk power.

Regional Transmission Organization

We are a member of the Southwest Power Pool (SPP). On October 1, 2004, FERC granted RTO status to the SPP. As a result, if approved by the KCC, we expect to transfer functional control of our transmission system to the SPP RTO under its membership agreement and applicable tariff. The SPP RTO will coordinate the operation of our transmission system within an interconnected transmission system across eight states. The SPP will collect revenues attributable to the use of each member's transmission system. Members and transmission customers will be able to transmit power purchased and generated for sale or bought for resale in the wholesale market throughout the entire SPP system. We believe each transmission owner generally retains the transmission capacity needed to serve its retail customers. Any additional transmission capacity will be sold on a first come/first served non-discriminatory basis. All transmission customers will be charged uniform rates for use of the transmission system, including entities that may sell power inside our certificated service territory. We do not expect that our participation in the SPP will have a material effect on our operations; however, we expect costs to increase due to the establishment of the RTO and associated markets. At this time, we are unable to quantify these costs because market implementation issues remain unresolved. We expect that we will recover these costs in rates we charge to our customers.

Real-Time Energy Imbalance Market

FERC requires RTOs to establish a real-time energy imbalance market. An energy imbalance exists when a transmission market participant's production and consumption of energy in real time does not net to zero. The intent of a real-time market system is to permit efficient balancing of production and consumption of energy and to manage congestion in real time. The SPP plans to implement a real-time energy imbalance market system on May 1, 2006. At this time, we are not able to identify the full impact on our results of operations.

Regulation and Rates

As a Kansas electric utility, we are subject to the jurisdiction of the KCC, which has 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.

Retail Rate Review

As discussed above in "– Significant Business Developments During 2005 – Retail Rate Review," our rates and cost of service were changed by the December 28, 2005 KCC Order.

FERC Proceedings

Request for Change in Transmission Rates: On May 2, 2005, we filed applications with FERC that propose a formula transmission rate that provides for annual adjustments to reflect changes in our transmission costs. This is consistent with our proposals filed with the KCC on May 2, 2005 to separately charge retail customers for transmission service. These rates became effective on December 1, 2005, subject to refund. We can provide no assurance that FERC will ultimately approve our applications as filed.

Market-based Rates: On March 23, 2005, FERC instituted a proceeding concerning the reasonableness of our market-based rates in our electric control area and the electrical control areas of Midwest Energy, Inc. and Aquila, Inc.'s West Plains Energy division. We have provided FERC with information it requested for its analysis. A FERC decision, anticipated in 2006, could affect how we price future wholesale power sales to wholesale customers in our control area and to Midwest Energy and West Plains Energy and wholesale customers in their control areas. We do not expect the outcome of this matter to significantly impact our consolidated results of operations.

Environmental Matters

General

We are subject to various federal, state and local environmental laws and regulations. These laws and regulations primarily relate to discharges into the air and air quality, discharges of effluents into water and the use of water, and the handling and disposal 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 and regulations, we could be fined or otherwise sanctioned by regulators. We have incurred and will continue to incur capital and other expenditures to comply with environmental laws and regulations. As discussed above, the December 28, 2005 KCC Order established the ECRR, which will allow for the timely inclusion in rates capital expenditures that are directly tied to environmental improvements required by the Clean Air Act.

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. Although we believe that we can recover in rates the costs relating to compliance with such laws and regulations, there can be no assurance that we will be able to recover all such increased costs from our customers or that our business, consolidated financial condition or results of operations will not be materially and adversely affected as a result of costs to comply with such existing and future laws and regulations.

Air Emissions

The Clean Air Act, state laws and implementing regulations impose, among other things, limitations on major pollutants, including SO2, particulate matter and nitrogen oxides (NOx).

Certain Kansas Department of Health and Environment (KDHE) regulations applicable to our generating facilities prohibit the emission of SO2 in excess of certain levels. In order to meet these standards, we use low-sulfur coal, fuel oil and natural gas and have equipped 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 some emissions. We have installed continuous monitoring and reporting equipment in order to meet the acid rain requirements. We have not had to make any material capital expenditures to meet Phase II SO2 and NOx 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 emissions allowances for each affected emitting 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 from operators of affected units that are anticipated to emit SO_2 in an amount less than their allowances. In 2005, we had enough emissions allowances to meet planned generation and we expect to have enough in 2006. The cost of emission allowances consumed is eligible to be recovered through the RECA. In future years, we expect to purchase SO_2 allowances in order to meet the acid rain requirements of the Clean Air Act. We cannot estimate the cost at this time, but anticipate these costs may be material. The pricing of emissions allowances is unpredictable and may change over time.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury emissions from coal-fired power plants. The Clean Air Mercury Rule requires reductions of mercury in two phases starting in 2010. To comply with this rule, additional controls at our coal-fired units will be required as well as the installation of additional emission monitoring equipment. Several different environmental groups and states are challenging this rule in court, which could potentially delay the implementation of this rule. To date, no part of the Clean Air Mercury Rule has been stayed by any court although court cases remain open. Assuming this rule is not stayed, the first significant compliance date for us will be the installation, certification and operation of mercury continuous emissions monitoring systems on each coal-fired unit by January 1, 2009. Based on currently available information, we cannot estimate our costs to comply with the Clean Air Mercury Rule, but these costs could be material.

On March 10, 2005, in a separate but related action, the EPA issued the Clean Air Interstate Rule (CAIR) that addresses the impact of interstate transport of air pollutants on downwind states. CAIR requires reductions of SO_2 and NO_x in certain states in two separate phases, the first in 2010 and the second in 2015. Several states, including Kansas, are not included in the CAIR region, which reduces the impact this rule has on us.

We may be required to further reduce emissions of SO_2, NO_x, particulate matter, mercury and carbon dioxide (CO_2) as a result of various other current or pending laws, including, in particular:

- the EPA's national ambient air quality standards for particulate matter and ozone,
- the EPA's regional haze rules, designed to reduce SO_2, NO_x and particulate matter emissions, and
- additional legislation introduced in the past few years in Congress, such as the various "multi-pollutant" bills sponsored by members of Congress requiring reductions of CO_2, NO_x, SO_2 and mercury, and the "Clear Skies" legislation proposed by the President, which would cap emissions of NO_x, SO_2 and mercury.

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

Environmental Projects

KCPL began updating or installing additional equipment related to emissions controls at La Cygne unit 1 for which we incurred costs beginning in 2005. We will continue to incur costs through the completion of installation in 2009. We anticipate that our share of these costs will be approximately $105.0 million. Additionally, we have identified the potential for up to $515.0 million of expenditures at other power plants for other environmental projects during the next 8 years. This cost could increase depending on the resolution of the EPA New Source Review described below. In addition to the capital investment, were we to install such equipment, we anticipate that we would incur significant annual expense to operate and maintain the equipment and the operation of the equipment would reduce net production from our plants. As discussed above, the ECRR will allow for the timely inclusion in rates capital expenditures that are directly tied to environmental improvements required by the Clean Air Act. However, increased operating and maintenance costs can only be recovered through a change in our base rates following a rate review.

EPA New Source Review

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 New Source Review requirements 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 have reasonably been expected to result in a significant net increase in emissions. The Clean Air Act requires companies to obtain permits and, if necessary, install control equipment to remove 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 the three coal-fired plants we operate. On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated pre-construction permitting requirements of the Clean Air Act.

We are in discussions with the EPA concerning this matter in an attempt to reach a settlement. We expect that any settlement with the EPA could require us to update or install emissions controls at Jeffrey Energy Center over an agreed upon number of years. 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. Together, these costs could be material. The EPA has informed us that it has referred this matter to the Department of Justice (DOJ) for the DOJ to consider whether to pursue an enforcement action in federal district court. We believe that costs related to updating or installing emissions controls would qualify for recovery through the ECRR. If we were to reach a settlement with the EPA, we may be assessed a penalty. The penalty could be material and may not be recovered in rates.

Manufactured Gas Sites

We have been associated with 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, our liability for twelve of the sites is limited. Of those twelve 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 and terminates in 2012. We have sole responsibility for remediation with respect to three sites.

Our liability for our former manufactured gas sites in Missouri is limited by an environmental indemnity agreement with Southern Union Company, which bought all of the Missouri manufactured gas sites. According to the terms of the agreement, our liability for these sites is capped at $7.5 million and terminates in 2009.

SEASONALITY

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

EMPLOYEES

As of February 28, 2006, we had 2,191 employees. Our current contract with Local 304 and Local 1523 of the International Brotherhood of Electrical Workers extends through June 30, 2008. The contract covered 1,281 employees as of February 28, 2006.

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.wr.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.

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During the Past Five Years
James S. Haines, Jr.	59	Director, Chief Executive Officer and President (since December 2002)	**The University of Texas at El Paso** Adjunct Professor and Skov Professor of Business Ethics (January 2002 to Present) **El Paso Electric Company** Director and Vice Chairman (December 2001 to November 2002) Director, President and Chief Executive Officer (May 1996 to November 2001)
William B. Moore	53	Executive Vice President and Chief Operating Officer (since December 2002)	**Saber Partners, LLC** Senior Managing Director and Senior Advisor (October 2000 to December 2002)
Mark A. Ruelle	44	Executive Vice President and Chief Financial Officer (since January 2003)	**Sierra Pacific Resources, Inc.** President, Nevada Power Company (June 2001 to May 2002) Senior Vice President, Chief Financial Officer (March 1997 to May 2001)
Douglas R. Sterbenz	42	Senior Vice President, Generation and Marketing (since October 2001)	**Westar Energy, Inc.** Senior Director, Bulk Power Marketing (January 1999 to October 2001)
Bruce A. Akin	41	Vice President, Administrative Services (since December 2001)	**Westar Energy, Inc.** Executive Director, Business Services (October 2001 to December 2001) Executive Director, Human Resources (July 1999 to October 2001)
Kelly B. Harrison	47	Vice President, Regulatory (since December 2001)	**Westar Energy, Inc.** Executive Director, Regulatory (October 2001 to December 2001) Senior Director, Restructuring and Rates (October 1999 to October 2001)
Larry D. Irick	49	Vice President, General Counsel and Corporate Secretary (since February 2003)	**Westar Energy, Inc.** Vice President and Corporate Secretary (December 2001 to February 2003) Corporate Secretary (May 2000 to December 2001)
Peggy S. Loyd	48	Vice President, Corporate Compliance and Internal Audit (since March 2003)	**Westar Energy, Inc.** Vice President, Financial Services (May 2000 to March 2003)
James J. Ludwig	47	Vice President, Public Affairs (since January 2003)	**Westar Energy, Inc.** Senior Director, Regulatory Affairs (July 1995 to October 2001)
Lee Wages	57	Vice President, Controller (since December 2001)	**Westar Energy, Inc.** Controller (July 1999 to December 2001)

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 performance of our customers. Our common stock price and 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 condition and results of operations. 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

The KCC regulates many aspects of our business and operations, including the retail rates that we charge customers for electric service. Retail rates are set by the KCC using a cost-of-service approach that takes into account historical operating expenses, fixed obligations and recovery of capital investments. Using this approach, the KCC sets rates at a level calculated to recover such costs and a permitted return on investment. Other parties to a rate review or the KCC staff may contend that our rates are excessive. Effective January 2006, the KCC authorized changes in our rates that left our rates virtually unchanged and approved various other changes in our rate structure. The KCC also approved the RECA, which is based on the actual cost of fuel and purchased power expense less margins earned on wholesale sales, and the ECRR, which is based on capital expenditures made to upgrade our equipment to meet stricter environmental standards required by the Clean Air Act.

Our Costs May Not be Fully Recovered in Retail Rates

Once established by the KCC, our rates generally remain fixed until changed in a subsequent rate review, except to the extent the KCC permits us to modify our tariffs using interim adjustment clauses, such as the RECA and the ECRR. We may elect to file a rate review to request a change in our rates or intervening parties may request that the KCC review our rates for possible adjustment, subject to any limitations that may have been ordered by the KCC.

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 a maintenance program in place, generating plants are subject to unplanned outages because of equipment failure. In these events, we must either produce replacement power from our less efficient units or purchase power from others at unpredictable and potentially higher cost in order to supply our customers and perform our contractual agreements. In addition, this can prevent us from having power to sell in the wholesale market. Coal deliveries from the PRB region of Wyoming, which is the primary source for our coal, have been slower than expected due primarily to problems with the rail tracks used to deliver our coal and operational problems at the mines where the coal is obtained. If rail delivery cycle times do not improve, we may be required to continue our coal conservation efforts and take other compensating measures. These measures 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 market-based 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, as well as weather, interest rates, economic conditions, fuel availability, deliverability and prices, price volatility of fuel and other commodities and transportation availability and costs are largely beyond our control. Costs that are not recovered through the RECA could have a material adverse effect on our consolidated earnings, cash flows and financial position. 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.

Table of Contents

We May Have Material Financial Exposure Under the Clean Air Act and Other Environmental Regulations

On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated pre-construction permitting requirements under the Clean Air Act. This notification was delivered as part of an investigation by the EPA regarding maintenance activities that have been conducted since 1980 at Jeffrey Energy Center. The EPA has informed us that it has referred this matter to the DOJ for it to consider whether to pursue an enforcement action in federal district court. The remedy for a violation could include fines and penalties and an order to install new emission control systems at Jeffrey Energy Center and at certain of our other coal-fired power plants, the associated cost of which could be material.

Our activities are subject to environmental regulation by federal, state, and local governmental authorities. These regulations generally involve the use of water, discharges of effluents into the water, emissions into the air, the handling, storage and use of hazardous substances, and waste handling, remediation and disposal, among others. Congress or the State of Kansas may enact legislation and the EPA or the State of Kansas may propose new regulations or change existing regulations that could require us to reduce certain emissions at our plants. Such action could require us to install costly equipment, increase our operating expense and reduce production from our plants.

The degree to which we will 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 regulations, new regulations, legislation, and the resolution of the EPA investigation described above. Although we expect to recover capital expenditures directly tied to environmental improvement through our rates, we can provide no assurance that we would be able to fully and timely recover all or any increased operating and maintenance costs relating to environmental compliance. Failure to recover these associated costs could have a material adverse effect on our consolidated financial condition or results of operations.

Competitive Pressures from Electric Industry Deregulation Could Adversely Affect Our Revenues and Reported Earnings

We currently apply the accounting principles of SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation,” to our regulated business. At December 31, 2005, we had recorded $275.0 million of regulatory assets, net of regulatory liabilities. At December 31, 2004, we had recorded $334.6 million of regulatory assets, net of regulatory liabilities. In the event that we determined that we could no longer apply the principles of SFAS No. 71, either as a result of the establishment of retail competition in our service territory or an expectation that permitted rates would not allow us to recover these costs, we would be required to record a charge against income in the amount of the remaining unamortized net regulatory assets.

We Face Financial Risks From Our Nuclear Facility

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 less efficient 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 by us in the wholesale markets. If we were not permitted by the KCC to recover these costs, such events could have an adverse impact on our consolidated financial condition.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

Table of Contents

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	72.0	—	72.0
Gordon Evans Energy Center:	Colwich, Kansas						
Steam Turbines		1	1961	Gas—Oil	—	149.0	149.0
		2	1967	Gas—Oil	—	383.0	383.0
Combustion Turbines		1	2000	Gas	74.0	—	74.0
		2	2000	Gas	74.0	—	74.0
		3	2001	Gas	151.0	—	151.0
Diesel Generator		1	1969	Diesel	—	3.0	3.0
Hutchinson Energy Center:	Hutchinson, Kansas						
Steam Turbines		1	1950	Gas—Oil	17.0	—	17.0
		2	1950	Gas—Oil	16.0	—	16.0
		3	1951	Gas—Oil	28.0	—	28.0
		4	1965	Gas—Oil	173.0	—	173.0
Combustion Turbines		1	1974	Gas	54.0	—	54.0
		2	1974	Gas	55.0	—	55.0
		3	1974	Gas	56.0	—	56.0
		4	1975	Diesel	77.0	—	77.0
Diesel Generator		1	1983	Diesel	3.0	—	3.0
Jeffrey Energy Center (84%):	St. Marys, Kansas						
Steam Turbines		1(a)	1978	Coal	471.0	147.0	618.0
		2(a)	1980	Coal	470.0	147.0	617.0
		3(a)	1983	Coal	474.0	148.0	622.0
Wind Turbines		1(a)	1999	—	0.5	0.1	0.6
		2(a)	1999	—	0.5	0.1	0.6
La Cygne Station (50%):	La Cygne, Kansas						
Steam Turbines		1(a)	1973	Coal	—	362.0	362.0
		2(b)	1977	Coal	—	337.0	337.0
Lawrence Energy Center:	Lawrence, Kansas						
Steam Turbines		3	1954	Coal	54.0	—	54.0
		4	1960	Coal	113.0	—	113.0
		5	1971	Coal	372.0	—	372.0
Murray Gill Energy Center:	Wichita, Kansas						
Steam Turbines		1	1952	Gas	—	40.0	40.0
		2	1954	Gas—Oil	—	71.0	71.0
		3	1956	Gas—Oil	—	104.0	104.0
		4	1959	Gas—Oil	—	102.0	102.0
Neosho Energy Center:	Parsons, Kansas						
Steam Turbine		3	1954	Gas—Oil	—	63.0	63.0
State Line (40%):	Joplin, Missouri						
Combined Cycle		2-1(a)	2001	Gas	65.0	—	65.0
		2-2(a)	2001	Gas	64.0	—	64.0
		2-3(a)	2001	Gas	71.0	—	71.0
Tecumseh Energy Center:	Tecumseh, Kansas						
Steam Turbines		7	1957	Coal	75.0	—	75.0
		8	1962	Coal	129.0	—	129.0
Combustion Turbines		1	1972	Gas	18.0	—	18.0
		2	1972	Gas	20.0	—	20.0
Wolf Creek Generating Station (47%):	Burlington, Kansas						
Nuclear		1(a)	1985	Uranium	—	548.0	548.0
Total					3,247.0	2,604.2	5,851.2

(a) We jointly own Jeffrey Energy Center (84%), La Cygne unit 1 generating unit (50%), Wolf Creek Generating Station (47%) and State Line (40%). Unit capacity amounts reflect our ownership only.
(b) In 1987, KGE entered into a sale-leaseback transaction involving its 50% interest in the La Cygne unit 2 generating unit.

We own approximately 6,100 miles of transmission lines, approximately 23,600 miles of overhead distribution lines and approximately 3,500 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.

Table of Contents

ITEM 3. LEGAL PROCEEDINGS

On September 21, 2004, a grand jury in Travis County, Texas, indicted us on charges that a $25,000 contribution by us in May 2002 to a Texas political action committee violated Texas election laws. We believe the indictment is without merit and we intend to vigorously defend against the charges. If convicted, the court could impose a fine of up to $20,000 or, in certain circumstances, in an amount not to exceed twice the amount caused to be lost by the commission of the felony. As a result of the indictment, the federal government could suspend our status as a government contractor. Upon a conviction, the federal government could bar us from acting as a government contractor. We are taking action to ensure that neither of these events occur, but we do not know whether we will be successful. We are unable to predict the ultimate impact either suspension or loss of our status as a government contractor would have on our consolidated financial position, results of operations and cash flows.

Information on other legal proceedings is set forth in Notes 3, 14, 16, 17 and 18 of the Notes to Consolidated Financial Statements, “Rate Matters and Regulation,” “Commitments and Contingencies – EPA New Source Review,” “Legal Proceedings,” “Ongoing Investigations” and “Potential Liabilities to David C. Wittig and Douglas T. Lake,” respectively, which are incorporated herein by reference.

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

No matter was submitted to a vote of our security holders through the solicitation of proxies or otherwise during the fourth quarter of 2005.

PART II

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

STOCK TRADING

Our common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 28, 2006, there were 27,604 common shareholders of record. For information regarding quarterly common stock price ranges for 2005 and 2004, see Note 24 of the Notes to Consolidated Financial Statements, “Quarterly Results (Unaudited).”

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 stock 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. On February 22, 2006, our board of directors declared a quarterly dividend of $0.25 per share on our common stock payable to shareholders on April 3, 2006. The indicated annual dividend rate is $1.00 per share. We expect to maintain the dividend at this level during 2006.

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 provide further information on these restrictions in Note 20 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.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

	For the Year Ended December 31,				
	2005	2004	2003 (In Thousands)	2002 (b)	2001
Income Statement Data:					
Sales	$1,583,278	$1,464,489	$1,461,143	$1,423,151	$1,308,536
Income from continuing operations before accounting change (a)	134,868	100,080	162,915	88,816	59,333
Earnings (loss) available for common stock	134,640	177,900	84,042	(793,400)	(21,771)

	As of December 31,				
	2005	2004	2003 (In Thousands)	2002	2001
Balance Sheet Data:					
Total assets	$5,210,069	$5,001,144	$5,672,520	$6,756,666	$7,718,764
Long-term obligations and mandatorily redeemable preferred stock (c)	1,681,301	1,724,967	2,259,880	3,225,556	2,915,153

	For the Year Ended December 31,				
	2005	2004	2003	2002 (b)	2001
Common Stock Data:					
Basic earnings per share available for common stock from continuing operations before accounting change	$ 1.54	$ 1.19	$ 2.24	$ 1.23	$ 0.83
Basic earnings (loss) per share available for common stock	$ 1.55	$ 2.14	$ 1.16	$ (11.06)	$ (0.31)
Dividends declared per share	$ 0.92	$ 0.80	$ 0.76	$ 1.20	$ 1.20
Book value per share	$ 16.31	$ 16.13	$ 13.98	$ 13.41	$ 25.64
Average equivalent common shares outstanding (in thousands)	86,855	82,941	72,429	71,732	70,650

(a) In 2002, we recognized a cumulative effect of accounting change of $623.7 million due to recording an impairment charge for goodwill. In 2001, we recognized a cumulative effect of accounting change of $18.7 million due to the adoption of SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities.”

(b) Our losses in 2002 were primarily attributable to impairment charges that were recorded for Protection One, Inc. and Protection One Europe.

(c) Includes long-term debt, capital leases, affiliate long-term debt and shares subject to mandatory redemption.

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 2005, and our operating results for the years ended December 31, 2005, 2004 and 2003. 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 us and our business operations since January 1, 2005.

- We filed applications with the KCC on May 2, 2005 for an increase in our retail electric rates. Effective January 2006, the KCC authorized changes in our rates that left our rates virtually unchanged and approved various other changes in our rate structure. See "– Retail Rate Review" below for additional information.
- We incurred approximately $38.1 million in maintenance costs and capital expenditures to restore our electric distribution system as a result of a severe ice storm that occurred in January 2005. As allowed by the December 28, 2005 KCC Order, we will begin to recover these costs in rates in 2006.
- Coal delivery issues caused our coal inventory levels to decline significantly below desired levels, which required us to rely on more expensive sources of power to meet our customers' energy needs.
- Wholesale sales volumes have declined and could continue to decline due to the cost and availability of fuel and growing demands of our retail customers.
- The cost of fuel and purchased power has increased significantly as discussed in more detail below in "– Increasing Cost of Fuel and Purchased Power."

Retail Rate Review

December 28, 2005 KCC Order

In accordance with a 2003 KCC order, we filed applications with the KCC on May 2, 2005 to review our rates. We requested an increase in our retail electric rates and the adoption of other practices under the KCC's jurisdiction. While the KCC ordered a net increase in our base rates of $38.8 million annually, the increase is substantially offset by the requirement that we credit to retail customers a rolling three-year average of the margins we realize from our market-based wholesale sales. Other significant changes approved by the KCC are the RECA, the ECRR, the separation of transmission delivery charges, an increase in annual depreciation expense, an extended recovery period for costs being recovered for which no return is provided and the recovery of various costs that have been incurred and deferred as regulatory assets.

Retail Energy Cost Adjustment: The RECA allows us to recover the actual cost of fuel consumed in producing electricity and the cost of purchased power. The adjustment is based on the actual cost of fuel and purchased power less margins from market-based wholesale sales. We have contracts with certain large industrial customers, the terms of which do not provide for the separate billing of fuel costs. Fuel costs for these customers will continue to be recovered through the rates specified in each of these contracts. These customers represented approximately 8% of our total retail sales volumes for 2005.

Wholesale Sales Margins: The terms of the RECA require that we include, as a credit to recoverable fuel costs, an amount based on the average of the margins realized from market-based wholesale sales during the immediately prior three-year period. In any period we are unable to realize market-based wholesale sales margins at least equal to the amount of the credit, our financial results would be adversely affected. In the short-term, our generating capacity is fixed while the load requirements of our customers change constantly. When our generating capacity is not needed to serve our customers, we attempt to seek out wholesale sales of energy at prices in excess of the costs of production. We are likely to face the prospect of decreasing margins as the energy demands of our retail customers increase, which may result in crediting to retail customers an amount that would exceed the margins realized in the current period.

Environmental Cost Recovery Rider: The ECRR allows for the timely inclusion in rates, without requiring a full rate review, of the capital expenditures made to upgrade our equipment to meet stricter environmental standards required by the Clean Air Act. Prior to collection through rates, the KCC will review any environmental expenditures to be considered for recovery under the ECRR. Any increased operating and maintenance costs that result from updating or adding environmental equipment cannot be recovered through the ECRR. These costs would be addressed in future rate reviews.

Transmission Delivery Charge: The December 28, 2005 KCC Order allows us to separate our transmission costs from our base rates charged to retail customers. This allows us to implement a formula transmission rate that provides for annual adjustments to reflect changes in our transmission costs, which provides for adjustment on a more timely basis. These rates were proposed in an application filed with FERC on May 2, 2005 and became effective on December 1, 2005, subject to refund upon review and approval by FERC.

Depreciation Rates: The December 28, 2005 KCC Order authorized an annual increase in the recovery of depreciation expense of approximately $27.6 million. The approved change in depreciation rates allows for the inclusion of net salvage costs, which include an estimate for the cost of dismantlement of plant facilities.

Disallowed Plant Costs: In 1985, the 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 original depreciable life of Wolf Creek, or through 2025, but disallowed any return on these costs. In its December 28, 2005 order, the KCC extended the recovery period to correspond to Wolf Creek's new estimated depreciable life. KGE recognized a loss of $10.4 million in the fourth quarter of 2005 as a result of the decrease in the present value of amounts to be received due to the extension of the recovery period.

Other Regulatory Assets: The December 28, 2005 KCC Order also approved for recovery approximately $50.3 million of deferred maintenance costs associated with restoring utility service to our customers stemming from damage to our lines and equipment in the ice storms that occurred in 2002 and 2005 and various other expenses that are relatively small in relation to the total regulatory asset balance.

Increasing Cost of Fuel and Purchased Power

The cost of power is impacted by, among other factors, customer demand, cost and availability of fuel and purchased power, price volatility, available generation capacity and operating constraints. Higher fuel and purchased power costs, unit outages, and operating constraints, such as our efforts to conserve coal, increased our total fuel and purchased power costs.

Cost of Fuel and Purchased Power: The cost of fossil fuel has increased since 2004. This is especially true for the cost of natural gas and oil. This higher cost of fuel affects not only the cost of fuel we burn, but also increases the market prices for both our wholesale sales and purchases of power. The cost and availability of fuel may cause us to use higher priced fuel types or to purchase power to meet our customers' energy needs. The effects of the fuel price increases are reflected in our operating results.

Fuel Supply Contracts: We have a net gain position on our coal supply contract for our Lawrence and Tecumseh Energy Centers. The gain position results primarily from an increase in the price of coal from the PRB region of Wyoming. Based on the terms of this contract, changes in the fair value of this contract are marked-to-market in accordance with the requirements of SFAS No. 133. As a result of the December 28, 2005 KCC Order implementing the RECA, we reversed previously recognized adjustments to fuel expense of $117.7 million related to mark-to-market adjustments and established a regulatory liability. Going forward, we will recognize changes in the fair value of fuel supply contracts as regulatory assets or liabilities.

Unit Availability: Our operating results are significantly influenced by the availability of our generating units. If our more economical units are not available, we must rely on more expensive sources of power to meet our load requirements. The primary outages during the year ended December 31, 2005 were the scheduled refueling and maintenance outage and an unplanned outage at Wolf Creek and planned and unplanned outages at Jeffrey Energy Center and La Cygne. The primary outages during the year ended December 31, 2004 were the planned and unplanned outages and reduced availability of Jeffrey Energy Center.

Operating Constraints: Our operating results are influenced by operating constraints on our generating units, such as coal conservation and maintenance outages. If our more economical units are constrained, we must rely on more expensive sources of power to meet our load requirements and/or forego opportunities in the wholesale power market. During the year ended December 31, 2005, coal conservation efforts, at times, reduced the energy generated at our more economical units and contributed to the decline in our market-based wholesale sales volumes. Coal conservation was required as a result of slower than expected coal deliveries, as discussed below.

Coal Inventory and Delivery: Coal deliveries from the PRB region of Wyoming were slower than expected due primarily to problems with the rail tracks used to deliver our coal and operational problems at the mines where the coal is obtained. Nearly all of the coal used in our coal-fired generating stations is from the PRB region of Wyoming.

During 2005, we implemented compensating measures based on delivery cycle times, our assumptions about future delivery cycle times, fuel usage and planned inventory levels. These measures included, but were not limited to, reducing coal consumption during off-peak periods by revising normal operational dispatch of our generating units, purchasing power or using more expensive power to serve customers, decreasing wholesale sales, transferring rail cars between or among our power plants and purchasing and leasing additional rail cars. These actions helped to reduce the financial impact resulting from longer delivery cycle times. The effect of the reduction in sales due to slower coal deliveries has been partially offset by higher prices received for the power we have sold in the power markets.

CRITICAL ACCOUNTING ESTIMATES

Our discussion and analysis of financial condition and results of operations are based on our consolidated financial statements, which have been prepared in conformity with generally accepted accounting principles (GAAP). Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies," contains a summary of our significant accounting policies, many of which require the use of estimates and assumptions by management. The policies highlighted below have an impact on our reported results that may be material due to the levels of judgment and subjectivity necessary to account for uncertain matters or susceptibility of matters 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 customer rates. Regulatory liabilities represent probable obligations to make refunds to customers for previous collections for costs that are not likely to be incurred in the future.

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 orders from the KCC, regulatory precedent and the current regulatory environment. To the extent recovery of costs is no longer deemed probable, related regulatory assets would be required to be expensed in current period earnings.

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” and SFAS No. 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions.”

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 benefit 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 Increase in Projected Pension Expense
		(In Thousands)		
Discount rate	0.5%decrease	$ 44,012	$ 34,772	$ 4,000
	0.5%increase	(41,317)	(32,775)	(3,925)
Salary scale	0.5%decrease	(10,520)	2,856	(1,030)
	0.5%increase	10,690	(2,841)	1,079
Rate of return on plan assets	0.5%decrease	—	—	2,252
	0.5%increase	—	—	(2,252)

We recorded pension expense of approximately $12.2 million in 2005, $5.1 million in 2004 and pension income of approximately $1.0 million in 2003. Pension expense for 2006 is expected to approximate $20.4 million, which represents an $8.2 million increase over 2005. The increase is primarily due to the amortization of investment losses from prior years that are recognized on a rolling four-year average basis and changes in assumptions including a lower discount rate, lower return on assets, increase in salary scale and updated mortality tables.

The following table shows the annual impact of a 0.5% change in our post-retirement benefit plan discount rate and rate of return on plan assets.

Actuarial Assumption	Change in Assumption	Annual Increase in Projected Benefit Obligation	Annual Increase in Projected Post-retirement Expense
		(In Thousands)	
Discount rate	0.5% decrease	$ 6,937	$ 376
	0.5% increase	(6,600)	(384)
Rate of return on plan assets	0.5% decrease	—	153
	0.5% increase	—	(155)

Revenue Recognition – Energy Sales

We recognize revenues from retail energy sales upon delivery to the customer and include an estimate for energy delivered but unbilled. Our estimate of revenue attributable to this unbilled portion is based on the total energy available for sale measured against billed sales. At December 31, 2005, we had estimated unbilled revenue of $42.1 million.

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 fuel contracts, 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 are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. Prices used to value these transactions reflect our best estimate of fair values of our trading positions. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

The tables below show fair value of energy marketing contracts outstanding for the year ended December 31, 2005, their sources and maturity periods.

	Fair Value of Contracts (In Thousands)
Net fair value of contracts outstanding at December 31, 2004	$ 6,081
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	(2,724)
Changes in fair value of contracts outstanding at the beginning and end of the period (a)	109,789
Fair value of new contracts entered into during the period	4,783
Fair value of contracts outstanding at December 31, 2005	$ 117,929

(a) Changes in the fair value of fuel supply contracts, approximately $117.7 million, are recognized as a regulatory liability.

The sources of the fair values of the financial instruments related to these contracts 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
	(In Thousands)			
Prices actively quoted (futures)	$ (792)	$ (792)	$ —	$ —
Prices provided by other external sources (swaps and forwards)	64,868	29,740	28,198	6,930
Prices based on the Black Option Pricing model (options and other) (a)	53,853	15,290	27,443	11,120
Total fair value of contracts outstanding	$117,929	$ 44,238	$55,641	$18,050

(a) The Black Option Pricing model is a variant of the Black-Scholes 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.

We record deferred tax assets for capital loss, operating loss and tax credit carryforwards. However, when there are not sufficient sources of 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, based on the weight of available evidence, it is considered more likely than not that some portion or all of the deferred tax asset will not be realized. We report the effect of a change in the valuation allowance in the current period tax expense.

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 the Financial Accounting Standards Board’s (FASB) Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations” (FIN 47).

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.

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 16 of the Notes to Consolidated Financial Statements, “Legal Proceedings,” for more detailed information.

OPERATING RESULTS

We evaluate operating results based on basic 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 revenues reserved for rebates.

Tariff-based wholesale: Sales of energy to electric cooperatives, municipalities and other electric utilities, the rate for which is generally based on cost as prescribed by FERC tariffs. Also includes changes in valuations of contracts that have yet to settle.

Market-based wholesale: Sales of energy to other wholesale customers, the rate for which is based on prevailing market prices as allowed by our FERC approved market-based tariff. Also includes changes in valuations of contracts that have yet to settle.

Energy marketing: Includes: (1) market-based energy transactions unrelated to our generation or the needs of our regulated customers; (2) financially settled products and physical transactions sourced outside our control area; and (3) changes in valuations for contracts that have yet to settle that may not be recorded in tariff- or market-based wholesale revenues.

Transmission: Reflects transmission revenues received, 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 overall economy of our service area, the weather and competitive forces. Our wholesale sales are impacted by, among other factors, demand, cost of fuel and purchased power, price volatility, available generation capacity and transmission availability. Changing weather affects the amount of electricity our customers use. Very hot summers and very cold winters prompt more demand, especially among our residential customers. Mild weather reduces demand.

2005 Compared to 2004

Below we discuss our operating results for the year ended December 31, 2005 as compared to the results for the year ended December 31, 2004. Changes in results of operations are as follows.

	Year Ended December 31, 2005	2004	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 458,806	$ 425,150	$ 33,656	7.9
Commercial	404,590	386,991	17,599	4.5
Industrial	242,383	239,518	2,865	1.2
Other retail	376	(46)	422	917.4
Total Retail Sales	1,106,155	1,051,613	54,542	5.2
Tariff-based wholesale	185,598	143,868	41,730	29.0
Market-based wholesale	145,628	140,465	5,163	3.7
Energy marketing	47,089	26,321	20,768	78.9
Transmission (a)	76,591	77,540	(949)	(1.2)
Other	22,217	24,682	(2,465)	(10.0)
Total Sales	1,583,278	1,464,489	118,789	8.1
OPERATING EXPENSES:				
Fuel used for generation	430,426	353,617	76,809	21.7
Purchased power	97,803	66,171	31,632	47.8
Operating and maintenance	437,741	412,002	25,739	6.2
Depreciation and amortization	150,520	169,310	(18,790)	(11.1)
Selling, general and administrative	166,060	173,498	(7,438)	(4.3)
Total Operating Expenses	1,282,550	1,174,598	107,952	9.2
INCOME FROM OPERATIONS	300,728	289,891	10,837	3.7
OTHER INCOME (EXPENSE):				
Investment earnings	11,365	16,746	(5,381)	(32.1)
Loss on extinguishment of debt	—	(18,840)	18,840	100.0
Other income	9,948	2,756	7,192	261.0
Other expense	(17,580)	(14,879)	(2,701)	(18.2)
Total Other Income (Expense)	3,733	(14,217)	17,950	126.3
Interest expense	109,080	142,151	(33,071)	(23.3)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	195,381	133,523	61,858	46.3
Income tax expense	60,513	33,443	27,070	80.9
INCOME FROM CONTINUING OPERATIONS	134,868	100,080	34,788	34.8
Results of discontinued operations, net of tax	742	78,790	(78,048)	(99.1)
NET INCOME	135,610	178,870	(43,260)	(24.2)
Preferred dividends	970	970	—	—
EARNINGS AVAILABLE FOR COMMON STOCK	$ 134,640	$ 177,900	$ (43,260)	(24.3)
BASIC EARNINGS PER SHARE	$ 1.55	$ 2.14	$ (0.59)	(27.6)

(a) **Transmission:** Includes an SPP network transmission tariff. In 2005, our SPP network transmission costs were approximately $66.2 million. This amount, less approximately $5.5 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2004, our SPP network transmission costs were approximately $66.6 million with an administration cost of $4.3 million retained by the SPP.

The following table reflects changes in electric sales volumes, as measured by thousands of megawatt hours (MWh) of electricity, for the years ended December 31, 2005 and 2004. No sales volumes are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to electricity we generate.

	2005	2004	Change	% Change
	(Thousands of MWh)			
Residential	6,384	5,925	459	7.7
Commercial	7,151	6,867	284	4.1
Industrial	5,581	5,470	111	2.0
Other retail	101	102	(1)	(1.0)
Total Retail	19,217	18,364	853	4.6
Tariff-based wholesale	5,490	4,573	917	20.1
Market-based wholesale	2,950	4,115	(1,165)	(28.3)
Total	27,657	27,052	605	2.2

Residential and commercial sales and sales volumes increased due primarily to warmer weather during 2005 than experienced in 2004. When measured by cooling degree days, the weather during 2005 was 27% warmer than during 2004 and 6% above the 20-year average. We measure cooling degree days at weather stations we believe to be generally reflective of conditions in our service territory.

The warmer weather also contributed to the increased tariff-based wholesale sales and sales volumes. Additionally, about $2.7 million, or approximately 2%, of the increase in the tariff-based wholesale sales was due to the Wolf Creek outages. We sold more tariff-based wholesale power to KEPCo in accordance with a contract to supply replacement power when Wolf Creek is not available. We had more energy available from Jeffrey Energy Center, which also contributed to the increased tariff-based wholesale sales.

Higher prevailing fuel prices have caused wholesale market prices to increase, which was the primary reason our market-based wholesale sales increased. Market-based wholesale sales volumes declined because less energy was available for sale due to the increase in retail and tariff-based wholesale sales.

The change in energy marketing was due primarily to having more favorable changes in market valuations in 2005 compared to 2004 and due to favorable settlements of energy contracts in 2005.

Fuel expense increased due primarily to using more expensive sources of generation because of the lower unit availability of our more economical generating units as discussed above in "– Summary of Significant Items – Increasing Cost of Fuel and Purchased Power – Unit Availability."

Purchased power expense increased due primarily to a 35% increase in volumes purchased during 2005 as compared to 2004. This was due to the various outages or reduced operating capability at some of our generating units and the availability of economically priced power. At times, it was more economical to purchase power than to operate our available generating units. Also contributing to the increase in purchased power expense was a 9% higher average cost.

Operating and maintenance expense increased due to a number of factors, the largest of which was a $10.4 million write-off of disallowed plant costs as discussed above in "– Summary of Significant Items – Retail Rate Review – December 28, 2005 KCC Order – Disallowed Plant Costs."

In addition, costs of operating and maintaining our distribution system increased $8.4 million due primarily to higher labor costs and additional maintenance projects. Also causing the operating and maintenance expense to increase was higher taxes other than income tax of $4.7 million, a $3.5 million charge to write off plant operating system development costs at Wolf Creek due to non-performance of the vendor developing the system and higher maintenance costs at our generating units of $2.8 million due to the outages as discussed above in "– Unit Availability." These higher expenses were partially offset by a $5.4 million decline in expense related to changes in the La Cygne unit 2 operating lease as discussed in Note 21 of the Notes to Consolidated Financial Statements, "Leases."

Depreciation expense decreased primarily because we established a regulatory asset for the depreciation differences between those used for financial statement purposes and regulatory rate making purposes from August 2001 to March 2002 pursuant to the December 28, 2005 KCC Order, which allowed us to record a reduction in depreciation expense of $20.1 million.

Selling, general and administrative expenses decreased due primarily to reduced legal fees and insurance costs. Partially offsetting these decreases were increased employee pension and benefit costs.

During 2004, we recognized a loss of $16.1 million in connection with the redemption of some of our senior unsecured notes and a loss of $2.7 million in connection with the redemption of the Western Resources Capital I 7-7/8% Cumulative Quarterly Income Preferred Securities, Series A.

Other income during 2005 was higher due primarily to $7.2 million of income from corporate-owned life insurance, which was partially offset by higher interest expense associated with borrowings on corporate-owned life insurance.

Interest expense decreased during 2005 due to lower debt balances and lower interest rates due to the refinancing activities as discussed in detail in "– Liquidity and Capital Resources" below.

The increase in income tax expense reflects the increase in income from continuing operations before income taxes.

2004 Compared to 2003

Below we discuss our operating results for the year ended December 31, 2004 as compared to the results for the year ended December 31, 2003. Changes in results of operations are as follows.

	Year Ended December 31,			
	2004	2003	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 425,150	$ 432,955	$ (7,805)	(1.8)
Commercial	386,991	382,585	4,406	1.2
Industrial	239,518	240,538	(1,020)	(0.4)
Other retail	(46)	5,363	(5,409)	(100.9)
Total Retail Sales	1,051,613	1,061,441	(9,828)	(0.9)
Tariff-based wholesale	143,868	140,687	3,181	2.3
Market-based wholesale	140,465	125,995	14,470	11.5
Energy marketing	26,321	31,881	(5,560)	(17.4)
Transmission (a)	77,540	76,379	1,161	1.5
Other	24,682	24,760	(78)	(0.3)
Total Sales	1,464,489	1,461,143	3,346	0.2
OPERATING EXPENSES:				
Fuel used for generation	353,617	342,522	11,095	3.2
Purchased power	66,171	47,790	18,381	38.5
Operating and maintenance	412,002	371,372	40,630	10.9
Depreciation and amortization	169,310	167,236	2,074	1.2
Selling, general and administrative	173,498	160,825	12,673	7.9
Total Operating Expenses	1,174,598	1,089,745	84,853	7.8
INCOME FROM OPERATIONS	289,891	371,398	(81,507)	(21.9)
OTHER INCOME (EXPENSE):				
Investment earnings	16,746	21,189	(4,443)	(21.0)
ONEOK dividends	—	17,316	(17,316)	(100.0)
Gain on sale of ONEOK stock	—	99,327	(99,327)	(100.0)
Loss on extinguishment of debt and settlement of putable/callable notes	(18,840)	(26,455)	7,615	28.8
Other income	2,756	2,854	(98)	(3.4)
Other expense	(14,879)	(16,590)	1,711	10.3
Total Other (Expense) Income	(14,217)	97,641	(111,858)	(114.6)
Interest expense	142,151	224,356	(82,205)	(36.6)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	133,523	244,683	(111,160)	(45.4)
Income tax expense	33,443	81,768	(48,325)	(59.1)
INCOME FROM CONTINUING OPERATIONS	100,080	162,915	(62,835)	(38.6)
Results of discontinued operations, net of tax	78,790	(77,905)	156,695	201.1
NET INCOME	178,870	85,010	93,860	110.4
Preferred dividends	970	968	2	0.2
EARNINGS AVAILABLE FOR COMMON STOCK	$ 177,900	$ 84,042	$ 93,858	111.7
BASIC EARNINGS PER SHARE	$ 2.14	$ 1.16	$ 0.98	84.5

(a) **Transmission:** Includes an SPP network transmission tariff. In 2004, our SPP network transmission costs were approximately $66.6 million. This amount, less $4.3 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2003, our SPP network transmission costs were approximately $65.3 million with an administration cost of $5.7 million retained by the SPP.

The following table reflects changes in electric sales volumes, as measured by thousands of MWh of electricity, for the years ended December 31, 2004 and 2003. No sales volumes are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to electricity we generate.

	2004	2003	Change	% Change
	(Thousands of MWh)			
Residential	5,925	6,031	(106)	(1.8)
Commercial	6,867	6,801	66	1.0
Industrial	5,470	5,448	22	0.4
Other retail	102	104	(2)	(1.9)
Total Retail	18,364	18,384	(20)	(0.1)
Tariff-based wholesale	4,573	4,747	(174)	(3.7)
Market-based wholesale	4,115	3,919	196	5.0
Total	27,052	27,050	2	—

Our retail customers used less energy and our sales decreased because of cooler weather during the summer. When measured by cooling degree days, the weather during 2004 was 12% cooler than during 2003 and 16% below the 20-year average. The accrual for rebates to be paid to customers in 2005 and 2006 pursuant to the July 25, 2003 KCC Order also reduced revenues from retail sales. During 2004, we accrued $8.5 million as compared to $3.5 million accrued during 2003.

Market-based wholesale sales increased due primarily to increased sales volumes and an approximate 6% increase in the average price per MWh. As a result of milder weather, we had additional energy production available for sale at certain times during the year that was not needed to serve our retail and tariff-based wholesale customers. Increased sales volumes accounted for approximately $6.7 million of the increased market-based wholesale sales and higher average market prices accounted for approximately $7.8 million of the increase. Energy marketing sales declined because we had less favorable changes in 2004 as compared to the favorable changes in 2003 in the settlement and the fair value of positions receiving mark-to-market accounting treatment.

Fuel expense increased due primarily to increases in the cost of fossil fuels, although we used approximately 2% less fuel for generation due to the lower demand caused by the cooler weather and due to unplanned outages or reduced operating capability experienced at some of our generating units at various times throughout 2004. The average equivalent availability factor for our system was 87% during 2004 compared to 90% in the prior year, due largely to the unavailability of some of our coal-fired generating units. As a result of the cooler weather and the reduced availability of our coal-fired generating units, we decreased the amount of coal burned, and consequently reduced our total expense for coal. However, the cost of natural gas and oil that we used at other generating facilities to compensate for the unplanned outages or reduced operating capability, increased our total fuel expense.

Purchased power expense increased due primarily to a 34% increase in volumes purchased during 2004 as compared to 2003. At times, it was more economical to purchase power than to operate our available generating units. This was due to unplanned outages or reduced operating capability of our coal-fired generating units at certain times, and the availability of economically priced power due to cooler weather in our region.

During 2003, we recorded as an offset to operating and maintenance expense a gain of $11.9 million on the sale of utility assets. The absence of a similar offset in 2004 accounted for 29% of the increase in operating and maintenance expense in 2004. The remainder of the increase was caused primarily by increased expenses associated with maintenance at Jeffrey Energy Center, increased planned and unplanned unit maintenance at various other generating units, increased maintenance of the distribution system, an increase in taxes other than income tax and an increase in the transmission costs. During 2004, increased maintenance of our generating units accounted for 23% of the increase in operating and maintenance expenses. The increase in distribution expenses accounted for 17% of the increase in operating and maintenance expenses. Distribution expenses increased due to increased staffing levels and higher costs associated with the termination of portions of the ONEOK shared services agreement as discussed in Note 22 of the Notes to Consolidated Financial Statements, “Related Party Transactions – ONEOK Shared Services Agreement.” The change in taxes other than income tax accounted for 22% of the increase in operating and maintenance expenses. An increase in transportation costs accounted for 3% of the increase in operating and maintenance expenses.

Selling, general and administrative expenses increased due primarily to an increase in legal fees, including amounts we were required to advance for fees incurred by David C. Wittig, our former president, chief executive officer and chairman, and Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, related to the defense of criminal charges against them, and fees associated with the pending shareholder class action and derivative lawsuits.

The total other expense during 2004 was due primarily to the loss incurred on the extinguishment of debt. The total other income during 2003 was due primarily to the gain on the sale of our ONEOK stock and dividends received from ONEOK in 2003. This gain was partially offset by the loss recorded on the extinguishment of debt and the settlement of notes during 2003.

Interest expense decreased in 2004 due to lower debt balances and lower interest rates due to refinancing activities as discussed below in "Liquidity and Capital Resources."

Income from discontinued operations was $78.8 million in 2004. The results recorded for 2004 include the settlement of previously pending issues as discussed in Note 23 of the Notes to Consolidated Financial Statements, "Discontinued Operations — Sale of Protection One and Protection One Europe." This compares to a loss from discontinued operations of $77.9 million in 2003.

FINANCIAL CONDITION

Below we discuss significant balance sheet changes at December 31, 2005 compared to December 31, 2004.

Accounts receivable increased $32.2 million due primarily to an increase in sales in late 2005 compared to late 2004. In addition, the amounts of receivables sold under our accounts receivable sales program as discussed in Note 4 of the Notes to Consolidated Financial Statements, "Accounts Receivable Sales Program," decreased $15.0 million, to $65.0 million at December 31, 2005, from $80.0 million at December 31, 2004.

Inventories and supplies decreased $22.7 million due primarily to a decline in our coal inventory as discussed above in "– Summary of Significant Items – Increasing Cost of Fuel and Purchased Power – Coal Inventory and Delivery."

Net energy marketing contracts increased $111.8 million, to $117.9 million at December 31, 2005, from $6.1 million at December 31, 2004. During 2005, we realized a large increase in the net gain position on fuel supply contracts. As a result of the December 28, 2005 KCC Order granting our request for the RECA, we recognized the cumulative mark-to-market adjustment associated with our coal supply contracts as a regulatory liability of $117.7 million. For additional information on the RECA and on the mark-to-market gain on fuel supply contracts, see "– Summary of Significant Items – Retail Rate Review," and "– Summary of Significant Items – Increasing Cost of Fuel and Purchased Power – Fuel Supply Contracts."

Our tax receivable balance declined $89.3 million primarily because we received a cash refund associated with the carry-back of our 2004 capital loss to 2003.

Regulatory assets, net of regulatory liabilities, decreased to $275.0 million at December 31, 2005, from $334.6 million at December 31, 2004, due primarily to changes that resulted from the December 28, 2005 KCC Order. Total regulatory assets increased $71.9 million due primarily to an increase in debt reacquisition costs associated with the retirement and refinancing of long-term debt, maintenance costs recorded in association with an ice storm that occurred in January 2005, an increase in depreciation due to changes authorized by the December 28, 2005 KCC Order and the recording of conditional asset retirement obligations. Total regulatory liabilities increased $131.5 million due primarily to the fuel supply contracts obligation we recorded in December 2005. As discussed above, we recorded a regulatory liability of $117.7 million to recognize the cumulative mark-to-market adjustments associated with our coal supply contracts. For additional information on our regulatory assets and liabilities, see Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies – Regulatory Accounting."

Other current assets increased $40.1 million due primarily to the recognition of the settlement of a consolidated purported class action lawsuit as discussed in detail in Note 16 of the Notes to Consolidated Financial Statements, “Legal Proceedings.”

Current maturities of long-term debt increased $35.0 million. The balance at December 31, 2005 consisted of the $100.0 million outstanding aggregate principal amount of KGE 6.2% first mortgage bonds that are due in January 2006. The balance at December 31, 2004 consisted of $65.0 million outstanding aggregate principal amount of KGE 6.5% first mortgage bonds that were due in August 2005.

Other current liabilities increased $41.2 million due primarily to the recognition of a receivable related to the settlement of a securities class action lawsuit as discussed in detail in Note 16 of the Notes to Consolidated Financial Statements, “Legal Proceedings.”

Long-term debt, net of current maturities, decreased $76.9 million due to various financing transactions and the recognition of $100.0 million KGE 6.2% first mortgage bonds as a current maturity as discussed below in “– Liquidity and Capital Resources – Debt Financings.”

Accrued employee benefits increased $38.3 million due primarily to the additional minimum pension liability recorded in 2005. For additional information, see Notes 12 and 13 of the Notes to Consolidated Financial Statements, “Employee Benefit Plans” and “Wolf Creek Employee Benefit Plans.”

Asset retirement obligations increased $42.8 million. In 2005, we determined that we have conditional asset retirement obligations that are within the scope of FIN 47 and, as a result, increased our asset retirement obligations by $21.2 million. Also during 2005, we updated our nuclear decommissioning and dismantlement study. Based upon the results of this study, we revised our estimate of our Wolf Creek asset retirement obligation and increased our liability by $14.6 million. In addition, we recorded $7.0 million in accretion expense on our asset retirement obligation related to the decommissioning of Wolf Creek. These items are discussed in greater detail in Note 15 of the Notes to Consolidated Financial Statements, “Asset Retirement Obligations.”

Total other long-term liabilities decreased $15.2 million due primarily to changes in the operating lease for La Cygne unit 2 as discussed in Note 21 of the Notes to Consolidated Financial Statements, “Leases.”

Accumulated other comprehensive income decreased $41.1 million due primarily to the additional minimum pension liability discussed in Notes 12 and 13 of the Notes to Consolidated Financial Statements, “Employee Benefit Plans” and “Wolf Creek Employee Benefit Plans.”

LIQUIDITY AND CAPITAL RESOURCES

Overview

We believe we will have sufficient cash to fund future operations, debt maturities and the payment of dividends from a combination of cash on hand, cash flows from operations and available borrowing capacity. Our available sources of funds include cash, Westar Energy’s revolving credit facility, our accounts receivable sales program and access to capital markets. Uncertainties affecting our ability to meet these cash requirements include, among others, factors affecting sales described in “Operating Results” above, economic conditions, regulatory actions, conditions in the capital markets and compliance with environmental regulations.

Capital Resources

At December 31, 2005, we had $38.5 million in unrestricted cash and cash equivalents. In addition, Westar Energy has a $350.0 million revolving credit facility against which $48.0 million of letters of credit have been issued, leaving $302.0 million available under this facility.

At December 31, 2005, we also had $2.4 million of restricted cash classified as a current asset and $25.0 million of restricted cash classified as a long-term asset, primarily to provide credit security for a prepaid capacity and transmission agreement. The following table details our restricted cash at December 31, 2005.

	Restricted Cash Current Portion	Restricted Cash Long-term Portion
	(In Thousands)	
Prepaid capacity and transmission agreement	$ 2,430	$ 23,552
Cash held in escrow as required by surety bonds	—	1,462
Total	$ 2,430	$ 25,014

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. Therefore, we must ensure that we will be able to 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. At December 31, 2005, based on an assumed interest rate of 6%, no 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. At December 31, 2005, based on an assumed interest rate of 6%, approximately $607.3 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

Westar Energy sold approximately 12.5 million shares of its common stock in 2004 for net proceeds of $245.1 million.

Cash Flows from Operating Activities

Cash flows from operating activities increased $8.3 million to $353.9 million in 2005 from $345.6 million in 2004. During 2005, we used approximately $33.1 million for system restoration costs related to the ice storm that affected our service territory in January 2005, and approximately $14.2 million for the Wolf Creek refueling outage. We also used cash for increases in fuel and purchased power costs. During 2005, we received approximately $47.5 million more in tax refunds than we did during 2004. Cash paid for interest was $40.4 million lower in 2005 than in 2004 due primarily to our lower debt balances.

Cash flows from operating activities increased $197.1 million to $345.6 million in 2004 from $148.5 million for 2003. This increase was primarily attributable to reduced interest of $80.2 million and reduced tax payments of $52.5 million.

Cash Flows (used in) from 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 $212.8 million in 2005, $197.1 million in 2004 and $163.3 million in 2003 on net additions to utility property, plant and equipment.

In 2004, we received net proceeds of $108.3 million from the sale of Protection One and Protection One bonds. During 2003, we received net proceeds of $801.8 million from the sale of ONEOK stock and net proceeds of $33.3 million from the sale of utility assets.

Cash Flows used in Financing Activities

Financing activities in 2005 used $127.9 million of cash compared to $323.2 million in 2004. In 2005, we received cash primarily from the issuance of long-term debt and we used cash primarily to retire long-term debt and pay dividends.

Financing activities in 2004 used $323.2 million of cash compared to $881.1 million in 2003. In 2004, we received cash from issuances of long-term debt and the issuance of common stock, and cash was used for the retirement of long-term debt and payment of dividends.

In 2003, cash was used in financing activities for the retirement of long-term debt and the payment of dividends. In 2003, we reduced our indicated annual dividend from $1.20 per share to $0.76 per share.

Future Cash Requirements

Our business requires significant capital investments. Through 2008, we expect we will need cash mostly for utility construction programs designed to improve facilities providing electric service, for future peaking capacity needs and to comply with environmental regulations. We anticipate that additional cash expenditures will be necessary to purchase and build additional peaking generation capacity that we anticipate will be needed in 2008. 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.

If we are required to update emissions controls or take other remedial action as a result of the EPA's investigation, the costs could be material. We may also have to pay fines or penalties or make significant capital or operational expenditures related to the notice of violation we received from the EPA in connection with certain projects completed at Jeffrey Energy Center. In addition, significant capital or operational expenditures may be required in order to comply with future environmental regulations or in connection with future remedial obligations. The following table does not include any amounts related to these possible expenditures. We expect that costs related to updating or installing emissions controls will be material. As discussed above, the ECRR will allow for timely inclusion in rates of the costs of capital expenditures directly tied to environmental improvements required by the Clean Air Act. We believe that other costs incurred would qualify for recovery through rates.

Capital expenditures for 2005 and anticipated capital expenditures for 2006 through 2008, including costs of removal, are shown in the following table.

	Actual 2005	2006	2007	2008
	(In Thousands)			
Generation:				
Replacements and other	$ 69,769	$ 82,900	$ 94,600	$ 92,500
Additional capacity	12,041	57,300	16,400	63,800
Environmental	7,657	28,500	135,900	153,500
Nuclear fuel	5,046	21,200	26,000	2,000
Transmission	13,598	22,600	26,700	24,400
Distribution:				
Replacements and other	42,099	39,300	37,000	37,100
New customers	47,758	54,600	55,700	57,000
Other	14,846	18,300	19,900	21,400
Total capital expenditures	$212,814	$324,700	$412,200	$451,700

We prepare these estimates for planning purposes and revise our estimates from time to time. Actual expenditures will differ from our estimates. These amounts do not include any estimate of expenditures that may be incurred as a result of the EPA investigation.

Maturities of long-term debt at December 31, 2005 are as follows.

Year	Principal Amount (In Thousands)
2006	$ 100,000
2007	—
2008	—
2009	145,078
Thereafter	1,417,912
Total long-term debt maturities	$ 1,662,990

Debt Financings

On January 17, 2006, KGE repaid the outstanding $100.0 million aggregate principal amount of KGE 6.2% first mortgage bonds with cash on hand and borrowings under the Westar Energy revolving credit facility. On August 1, 2005, KGE repaid the outstanding $65.0 million aggregate principal amount of KGE 6.5% first mortgage bonds with cash on hand and borrowings under the Westar Energy revolving credit facility.

On June 30, 2005, Westar Energy sold $400.0 million aggregate principal amount of Westar Energy first mortgage bonds, consisting of $150.0 million of 5.875% bonds maturing in 2036 and $250.0 million of 5.1% bonds maturing in 2020. On July 27, 2005, proceeds from the offering were used to redeem the outstanding $365.0 million aggregate principal amount of Westar Energy's 7.875% first mortgage bonds due 2007, together with accrued interest and a call premium equal to approximately 6% of the principal outstanding, and for general corporate purposes. The call premium is recorded as a regulatory asset and is being amortized over the term of the new bonds.

On May 6, 2005, Westar Energy amended its revolving credit facility dated March 12, 2004 to extend the term and reduce borrowing costs. The amended revolving credit facility matures on May 6, 2010. The facility is used as a source of short-term liquidity. It allows us to borrow up to an aggregate amount of $350.0 million, including letters of credit up to a maximum aggregate amount of $100.0 million. So long as there is no default or event of default under the revolving credit facility, Westar Energy may elect, subject to lender participation, to increase the aggregate amount of borrowings under this facility to $500.0 million. All borrowings under the revolving credit facility are secured by KGE first mortgage bonds. At December 31, 2005, we had no outstanding borrowings and $48.0 million of letters of credit outstanding under this facility.

A default by Westar Energy or KGE under other indebtedness totaling more than $25.0 million is 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. 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.

On January 18, 2005, Westar Energy sold $250.0 million aggregate principal amount of Westar Energy first mortgage bonds, consisting of $125.0 million 5.15% bonds maturing in 2017 and $125.0 million 5.95% bonds maturing in 2035. On February 17, 2005, we used the net proceeds from the offering, together with cash on hand, additional funds raised through the accounts receivable conduit facility and borrowings under Westar Energy's revolving credit facility, to redeem the remaining $260.0 million aggregate principal amount of Westar Energy 9.75% senior notes due 2007. Together with accrued interest and a premium equal to approximately 12% of the outstanding senior notes, we paid $298.5 million to redeem the Westar Energy 9.75% senior notes due 2007. The call premium is recorded as a regulatory asset and is being amortized over the term of the new bonds.

On June 10, 2004, KGE refinanced $327.5 million of pollution control bonds. The original issue had an interest rate of 7% and was due in 2031. This issue was replaced with pollution control bonds at interest rates of 5.3% on $127.5 million that matures in 2031, 2.65% on $100.0 million that matures in 2031, and a variable rate on $100.0 million that matures in 2031.

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 at December 31, 2005.

Affiliate Long-Term Debt and Other Mandatorily Redeemable Securities

On December 14, 1995, Western Resources Capital I, a wholly owned trust, issued $100.0 million of 7-7/8% Cumulative Quarterly Income Preferred Securities, Series A. On April 16, 2004, we redeemed our entire issuance of Western Resources Capital I 7-7/8% Cumulative Quarterly Income Preferred Securities, Series A, at par.

On July 31, 1996, Western Resources Capital II, a wholly owned trust, issued $120.0 million of 8-1/2% Cumulative Quarterly Income Preferred Securities, Series B. On September 22, 2003, we redeemed our entire issuance of Western Resources Capital II 8-1/2% Cumulative Quarterly Income Preferred Securities, Series B, at par.

Interest Rate Swap

Effective October 4, 2001, we entered into a $500.0 million interest rate swap agreement with a term of two years. At that time, the effect of the swap agreement was to fix the annual interest rate on a term loan at 6.18%. We settled the swap agreement for a nominal amount on September 29, 2003. For information regarding ongoing interest rates, see Note 10, of the Notes to Consolidated Financial Statements, “Long-Term Debt.”

Credit Ratings

Standard & Poor’s Ratings Group (S&P), Moody’s Investors Service (Moody’s) and Fitch Investors Service (Fitch) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies’ assessment of our ability to pay interest and principal when due on our securities.

On January 30, 2006, Moody’s lowered our speculative grade liquidity rating to SGL-2 (good) from SGL-1 (very good). On February 23, 2005, Moody’s upgraded its ratings for our debt. Secured debt ratings for us and KGE were upgraded to Baa3 from Ba1. Our unsecured ratings were upgraded to Ba1 from Ba2. On December 22, 2004, Fitch raised its outlook for our ratings to positive from stable and affirmed its ratings as shown in the table below. On July 22, 2004, S&P improved its ratings on KGE’s first mortgage bonds to BBB from BB+.

As of March 1, 2006, ratings with these agencies are as shown in the table below.

	Westar Energy Mortgage Bond Rating	Westar Energy Unsecured Debt	KGE Mortgage Bond Rating
S&P	BBB-	BB-	BBB
Moody’s	Baa3	Ba1	Baa3
Fitch	BBB-	BB+	BBB-

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are economically favorable to us. Westar Energy and KGE have credit rating conditions under our revolving credit agreement and in the agreements governing the sale of our accounts receivable discussed in Note 4 of the Notes to Consolidated Financial Statements, “Accounts Receivable Sales Program,” that affect the cost of borrowing but do not trigger a default. We may enter into new credit agreements that contain credit conditions, which could affect our liquidity and/or our borrowing costs.

Capital Structure

At December 31, 2005 and 2004, our capital structure consisted of 45% common equity, 1% preferred stock and 54% long-term debt.

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2005, we did not have any off-balance sheet financing arrangements, other than our accounts receivable sales program and operating leases entered into in the ordinary course of business.

Accounts Receivable Sales Program

Under a revolving accounts receivable sales program, we can currently sell up to $125.0 million of our accounts receivable. For additional detail, see Note 4 of the Notes to Consolidated Financial Statements, “Accounts Receivable Sales Program.”

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 do not include amounts for on-going needs for which no contractual obligations existed at December 31, 2005. We may from time to time enter into new contracts to replace contracts that expire.

Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing at December 31, 2005.

	Total	2006 (c)	2007 - 2008	2009 - 2010	Thereafter
			(In Thousands)		
Long-term debt (a)	$ 1,662,990	$ 100,000	$ —	$ 145,078	$ 1,417,912
Interest on long-term debt (b)	1,477,964	84,376	162,552	152,216	1,078,820
Adjusted long-term debt	3,140,954	184,376	162,552	297,294	2,496,732
Wolf Creek pension benefit funding obligations (c)	6,000	6,000	—	—	—
Capital leases (d)	23,378	5,845	8,829	5,071	3,633
Operating leases (e)	579,986	44,637	74,055	79,302	381,992
Fossil fuel (f)	1,524,945	209,548	369,938	297,761	647,698
Nuclear fuel (g)	147,453	24,902	19,595	15,398	87,558
Unconditional purchase obligations	36,759	32,210	4,534	15	—
Miscellaneous obligations (h)	11,227	10,827	400	—	—
Total contractual obligations, including adjusted long-term debt	$ 5,470,702	$ 518,345	$ 639,903	$ 694,841	$ 3,617,613

(a) See Note 10 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 at December 31, 2005.
(c) Pension benefit funding obligations represent only the minimum funding requirements under the Employee Retirement Income Securities Act of 1974. Minimum funding requirements for future periods are not yet known. Our funding policy is to contribute amounts sufficient to meet the minimum funding requirements plus additional amounts as deemed fiscally appropriate; therefore, actual contributions may differ from expected contributions. See Notes 12 and 13 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.
(e) Includes the La Cygne unit 2 lease, office space, operating facilities, office equipment, operating equipment 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 obligation to pay rebates of $10.0 million to customers in 2006. Other miscellaneous obligations are also included in this line item.

Commercial Commitments

Our commercial commitments existing at December 31, 2005 consist of outstanding letters of credit that expire in 2006. The letters of credit are comprised of $38.8 million related to our energy marketing and trading activities, $4.3 million related to worker’s compensation and $5.3 million related to other operating activities for a total outstanding balance of $48.4 million.

OTHER INFORMATION

Agreement to Purchase Electric Generation Facility

On October 21, 2005, we entered into an agreement to purchase a 300 MW electric generation facility from ONEOK Energy Services Company, L.P. for $53.0 million. The agreement also requires us to assume a capacity sale agreement with the Oklahoma Municipal Power Authority for 75 MW through 2015. The transaction is subject to a number of conditions, including FERC approval. We expect the transaction to close in 2006.

Sale of Utility Assets

In August 2003, we sold a portion of our transmission and distribution assets and rights to provide service to approximately 10,000 customers in an area of central Kansas. Total sales proceeds received were $33.3 million and we realized a gain of $11.9 million.

Payment of Rebates

On July 25, 2003, the KCC issued an order approving a Stipulation and Agreement, the principal terms of which included a requirement for us to pay customer rebates of $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006. The first rebate appeared as credits on customers' billing statements in May and June of 2005. The second rebate appeared as credits on customers' billing statements in January of 2006.

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.

At December 31, 2005, we had recorded regulatory assets currently subject to recovery in future rates of approximately $437.5 million and regulatory liabilities of $162.5 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

In accordance with SFAS No. 143, adopted January 2003, and FIN 47, adopted December 31, 2005, 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.

Legal Liability

On January 1, 2003, we recognized the liability for our 47% share of the estimated cost to decommission Wolf Creek. SFAS No. 143 requires the recognition of the fair value of the asset retirement obligation we incurred at the time Wolf Creek was placed into service in 1985. On January 1, 2003, we recorded an asset retirement obligation of $74.7 million. In addition, we increased our property and equipment balance, net of accumulated depreciation, by $10.7 million.

During 2005 we updated our nuclear decommissioning and dismantlement study. Based on the results of the 2005 study, we have revised our estimate of our Wolf Creek asset retirement obligation. Accordingly, in 2005 we increased our asset retirement liability $14.6 million. Costs to retire Wolf Creek are currently being recovered through rates as provided by the KCC.

During 2005 we determined that we have conditional asset retirement obligations that are within the scope of FIN 47. The conditional asset retirement obligations include disposal of asbestos insulating material at our power plants, remediation of ash disposal ponds and the disposal of polychlorinated biphenyl (PCB) contaminated oil. As of December 31, 2005, we recorded an asset retirement obligation of approximately $21.2 million pursuant to the requirements of FIN 47 based on the fair value of these disposal obligations.

The amount of the retirement obligation related to asbestos disposal was recorded as of 1990, the date when the Environmental Protection Agency published the "National Emission Standards for Hazardous Air Pollutants: Asbestos NESHAP Revision; Final Rule." We also capitalized the retirement obligation as an increase to the asset's carrying value. The amount of the asset retirement obligation related to asbestos disposal was $9.3 million at December 31, 2005.

We operate, as permitted by the state of Kansas, ash landfills at several of our power plants. We have determined that the closure of these facilities represents a conditional asset retirement obligation as defined by FIN 47. Accordingly, we have recognized an asset retirement obligation for the ash landfills. The liability was determined based upon the date each landfill was originally placed in service. The amount of the asset retirement obligation related to remediation of ash disposal ponds was $10.9 million at December 31, 2005.

PCB contaminates are contained within company electrical equipment, primarily transformers. We have determined that the disposal of PCB-contaminated equipment represents a conditional asset retirement obligation as defined by FIN 47. Accordingly, we have recognized an asset retirement obligation for the PCB-contaminated equipment. The liability was determined based upon the PCB regulations that originally became effective in 1978. The amount of the asset retirement obligation related to the disposal of PCB contaminated oil was $1.0 million at December 31, 2005.

For additional information on our legal asset retirement obligations, see Note 15 of the Notes to Consolidated Financial Statements, “Asset Retirement Obligations.”

Non-Legal Liability – Cost of Removal

We recover in rates, as a component of depreciation, the costs to dispose of utility plant assets that do not represent legal retirement obligations. At December 31, 2005 and 2004, Westar Energy had incurred, but had not recovered, $0.3 million and $1.3 million, respectively, in removal costs, which were classified as a regulatory asset. At December 31, 2005 and 2004, KGE had $6.9 million and $2.6 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.

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 beneficially owned 354.4 shares of the Guardian Series D preferred stock and 312.9 shares of the Guardian Series E preferred stock. We will record a gain in 2006 of approximately $0.3 million as a result of the payment for these shares. Certain current and former officers beneficially owned the remaining shares. Of these shares, 14,094 shares of Guardian Series D preferred stock and 7,276 shares of Guardian Series E preferred stock were beneficially owned by Mr. Wittig and Mr. Lake. The ownership of the shares beneficially owned by Mr. Wittig and Mr. Lake, as well as related dividends, is disputed and is the subject of the arbitration proceeding with Mr. Wittig and Mr. Lake discussed in Note 16 of the Notes to Consolidated Financial Statements, “Legal Proceedings.” These shares were also part of the property forfeited by Mr. Wittig and Mr. Lake in the criminal proceeding discussed in Note 18 of the Notes to Consolidated Financial Statements, “Potential Liabilities to David C. Wittig and Douglas T. Lake.” As a result of this transaction, we no longer hold any Guardian securities.

New Accounting Pronouncements

Share-Based Payment: In December 2004, FASB issued SFAS No. 123R, “Share-Based Payment.” SFAS No. 123R requires companies to recognize as compensation expense the grant-date fair value of stock options and other equity-based compensation issued to employees. We implemented the provisions of the statement on January 1, 2006. We currently use RSUs for stock-based awards granted to employees. Given the characteristics of our stock-based compensation program, we do not expect the adoption of SFAS No. 123R to materially impact our consolidated results of operations.

Accounting Changes and Error Corrections: On May 30, 2005, the FASB issued SFAS No. 154, “Accounting Changes and Error Corrections – Replacement of APB 20 and SFAS No. 3,” which changes the requirements for the accounting and reporting of a change in accounting principle. SFAS No. 154 applies to all voluntary changes in accounting principle as well as to changes required by an accounting pronouncement that does not include specific transition provisions. For most accounting changes and error corrections, SFAS No. 154 requires retrospective application, under which the new accounting principle is applied as of the beginning of the first period presented as if that principle had always been used. SFAS No. 154 is effective for accounting changes and corrections of errors made beginning January 1, 2006.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Hedging Activity

We may use derivative financial and physical instruments to economically hedge the price of a portion of our anticipated fossil fuel needs. At the time we enter into these transactions, we are unable to determine what the value will be when the agreements are actually settled.

In an effort to mitigate market risk associated with fuel and energy prices, we may use economic hedging arrangements to reduce our exposure to price changes. 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.

See Note 5 of the Notes to Consolidated Financial Statements, “Financial Instruments, Energy Marketing and Risk Management — Derivative Instruments and Hedge Accounting — Hedging Activities,” for detailed information regarding hedging relationships and an interest rate swap we entered into during the third quarter of 2001.

Market Price Risks

Our economic hedging and trading activities involve risks, including commodity price risk, interest rate risk and credit risk. Commodity price risk is the risk that changes in commodity prices may impact the price at which we are able to buy and sell electricity and purchase fuels for our generating units. We believe we will continue to experience volatility in the prices for these commodities.

Interest rate risk represents the risk of loss associated with movements in market interest rates. In the future, we may use swaps or other financial instruments to manage interest rate risk.

Credit risk represents the risk of loss resulting from non-performance by a counterparty of its contractual obligations. We have exposure to credit risk and counterparty default risk with our retail, wholesale and energy marketing activities. We maintain credit policies intended to reduce overall credit risk. We employ additional credit risk control mechanisms that we believe are appropriate, such as letters of credit, parental guarantees and master netting agreements with counterparties that allow for offsetting exposures. Results actually achieved from economic hedging and trading activities could vary materially from intended results and could materially affect our consolidated financial results depending on the success of our credit risk management efforts.

Commodity Price Exposure

We may engage in both financial and physical trading to manage our commodity price risk. We trade electricity, coal, natural gas and oil. We use a variety of financial instruments, including forward contracts, options and swaps, and we trade energy commodity contracts. We may also use economic hedging techniques to manage overall fuel expenditures. We procure physical products under forward agreements and spot market transactions.

We are involved in trading activities 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 position or results of operations. Our risk of loss, in the form of increased costs, from market price changes in fuel is mitigated through the RECA, which provides for inclusion of most fuel costs in retail rates.

We manage and measure the market price risk exposure of our trading portfolio using a variance/covariance value-at-risk (VaR) model. The VaR model is designed to measure the predicted maximum one-day loss at a 95% confidence level. 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 2006.

The use of the VaR method requires assumptions, including the selection of a confidence level for potential losses and the estimated holding period. We are also exposed to the risk that we value and mark illiquid prices incorrectly. We express VaR as a potential dollar loss based on a 95% confidence level using a one-day holding period. The calculation includes derivative commodity instruments used for both trading and risk management purposes. The VaR amounts for 2005 and 2004 were as follows.

	2005	2004
	(In Thousands)	
High	$12,480	$2,891
Low	522	713
Average	3,441	1,321

We have considered a number of risks and costs associated with the future contractual commitments included 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 we believe are effective in managing overall credit risk. There can be no assurance that the employment of VaR, or other risk management tools we employ, will eliminate the possibility of a loss.

We are also exposed to commodity price changes outside of trading activities. We use derivative contracts for non-trading purposes and a mix of various fuel types primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power market is 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. The loss of revenues associated with this could be material and adverse to our consolidated results of operations and financial condition.

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 used for generation vary from year to year based on availability, price and deliverability of a given fuel type as well as planned and scheduled 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 the weather or other factors.

Interest Rate Exposure

We have entered into various fixed and variable rate debt obligations. For details, see Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt." Sensitivity to changes in interest rates for variable rate debt and current maturities of fixed rate debt is computed 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 $321.9 million of variable rate debt and current maturities of fixed rate debt at December 31, 2005. A 100 basis point change in interest rates applicable to this debt would impact operating income on an annualized basis by approximately $2.3 million.

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, 2005, these funds were comprised of 66% domestic equity securities, 24% debt securities and 10% cash and cash equivalents. The fair value of these funds was $100.8 million as of December 31, 2005 and $91.1 million as of December 31, 2004. By maintaining a portfolio that includes long-term equity investments, we seek to maximize the returns to be utilized to fund nuclear decommissioning costs within acceptable parameters of risk. However, the equity securities included in the portfolio are exposed to price fluctuations in equity markets and the fixed-rate, fixed-income securities are exposed to changes in interest rates. We actively monitor the portfolio by benchmarking the performance of the investments against certain indices and by maintaining and periodically reviewing established target allocation percentages of the assets of the trusts to various investment options. Our exposure to equity price market risk is, in large part, mitigated, due to the fact that we are currently allowed to recover decommissioning costs in our electric rates, which would include unfavorable investment results.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

SCHEDULES OMITTED

The following schedules are omitted because of the absence of the conditions under which they are required or the information is included 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 at December 31, 2005. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework. Based on the assessment, we believe that, at December 31, 2005, our internal control over financial reporting is effective based on those criteria. Our independent registered public accounting firm has issued an audit report on our assessment of our internal control over financial reporting.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Shareholders of Westar Energy, Inc.
Topeka, Kansas

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Westar Energy, Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, 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, 2005 of the Company and our report dated March 10, 2006 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding revisions made to the consolidated statements of cash flows for the years ended December 31, 2004 and 2003.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
March 10, 2006

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, 2005 and 2004, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2005. 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 these 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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.

In 2005, the Company changed the presentation of its consolidated statements of cash flows to present separate disclosure of the cash flows from operating, investing, and financing activities of discontinued operations and other matters, as discussed in Note 2 and retroactively revised the consolidated statements of cash flows for the years ended December 31, 2004 and 2003, for the change.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, 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 March 10, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
March 10, 2006

Table of Contents

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

	As of December 31, 2005	2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 38,539	$ 24,611
Restricted cash	2,430	2,256
Accounts receivable, net	124,711	92,532
Inventories and supplies, net	101,818	124,563
Energy marketing contracts	55,948	23,155
Tax receivable	1,565	90,845
Deferred tax assets	19,211	—
Prepaid expenses	30,452	29,179
Regulatory assets	39,300	16,137
Other	61,646	21,580
Total Current Assets	475,620	424,858
PROPERTY, PLANT AND EQUIPMENT, NET	3,947,732	3,910,987
OTHER ASSETS:		
Restricted cash	25,014	27,408
Regulatory assets	398,198	349,458
Nuclear decommissioning trust	100,803	91,095
Energy marketing contracts	75,698	4,904
Other	187,004	192,434
Total Other Assets	786,717	665,299
TOTAL ASSETS	$5,210,069	$5,001,144
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 100,000	$ 65,000
Accounts payable	109,807	105,593
Accrued taxes	100,568	97,874
Energy marketing contracts	11,710	20,431
Accrued interest	36,609	30,506
Deferred tax liabilities	—	2,163
Regulatory liabilities	50,970	1,553
Other	140,403	99,170
Total Current Liabilities	550,067	422,290
LONG-TERM LIABILITIES:		
Long-term debt, net	1,562,990	1,639,901
Deferred income taxes	911,135	917,706
Unamortized investment tax credits	65,558	68,957
Deferred gain from sale-leaseback	130,513	138,981
Accrued employee benefits	158,418	120,152
Asset retirement obligation	129,888	87,118
Energy marketing contracts	2,007	1,547
Regulatory liabilities	111,523	29,466
Other	150,531	165,704
Total Long-Term Liabilities	3,222,563	3,169,532
COMMITMENTS AND CONTINGENCIES (see Notes 14 and 16)		
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 86,835,371 shares and 86,029,721 shares, respectively	434,177	430,149
Paid-in capital	923,083	912,932
Unearned compensation	(10,257)	(10,361)
Retained earnings	109,987	55,053
Accumulated other comprehensive (loss) income, net	(40,987)	113
Total Shareholders' Equity	1,437,439	1,409,322
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$5,210,069	$5,001,144

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

Table of Contents

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

	Year Ended December 31, 2005	2004	2003
SALES	$ 1,583,278	$ 1,464,489	$ 1,461,143
OPERATING EXPENSES:			
Fuel and purchased power	528,229	419,788	390,312
Operating and maintenance	437,741	412,002	371,372
Depreciation and amortization	150,520	169,310	167,236
Selling, general and administrative	166,060	173,498	160,825
Total Operating Expenses	1,282,550	1,174,598	1,089,745
INCOME FROM OPERATIONS	300,728	289,891	371,398
OTHER INCOME (EXPENSE):			
Investment earnings	11,365	16,746	38,505
Gain on sale of ONEOK, Inc. stock	—	—	99,327
Loss on extinguishment of debt and settlement of putable/callable notes	—	(18,840)	(26,455)
Other income	9,948	2,756	2,854
Other expense	(17,580)	(14,879)	(16,590)
Total Other Income (Expense)	3,733	(14,217)	97,641
Interest expense	109,080	142,151	224,356
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	195,381	133,523	244,683
Income tax expense	60,513	33,443	81,768
INCOME FROM CONTINUING OPERATIONS	134,868	100,080	162,915
Results of discontinued operations, net of tax	742	78,790	(77,905)
NET INCOME	135,610	178,870	85,010
Preferred dividends	970	970	968
EARNINGS AVAILABLE FOR COMMON STOCK	$ 134,640	$ 177,900	$ 84,042
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (see Note 2):			
Basic earnings available from continuing operations	$ 1.54	$ 1.19	$ 2.24
Discontinued operations, net of tax	0.01	0.95	(1.08)
Basic earnings available	$ 1.55	$ 2.14	$ 1.16
Diluted earnings available from continuing operations	$ 1.53	$ 1.19	$ 2.20
Discontinued operations, net of tax	0.01	0.94	(1.06)
Diluted earnings available	$ 1.54	$ 2.13	$ 1.14
Average equivalent common shares outstanding	86,855,485	82,941,374	72,428,728
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.92	$ 0.80	$ 0.76

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,					
	2005		2004		2003	
NET INCOME		$135,610		$178,870		$85,010
OTHER COMPREHENSIVE INCOME (LOSS):						
Unrealized holding gain on marketable securities arising during the period	$ 45		$ 11		$ 99,412	
Reclassification adjustment for gain included in net income	—	45	—	11	(99,310)	102
Unrealized holding gain on cash flow hedges arising during the period	—		—		12,270	
Reclassification adjustment for gain included in net income	—	—	—	—	(4,543)	7,727
Minimum pension liability adjustment		(68,321)		7,769		284
Other comprehensive (loss) income, before tax		(68,276)		7,780		8,113
Income tax benefit (expense) related to items of other comprehensive income		27,176		(3,090)		(3,188)
Other comprehensive (loss) income, net of tax		(41,100)		4,690		4,925
COMPREHENSIVE INCOME		$ 94,510		$183,560		$89,935

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

Table of Contents

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

	Year Ended December 31,		
	2005	2004 Revised (See Note 2)	2003 Revised (See Note 2)
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$ 135,610	$ 178,870	$ 85,010
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations, net of tax	(742)	(78,790)	77,905
Depreciation and amortization	150,520	169,310	167,236
Amortization of nuclear fuel	13,315	14,221	12,410
Amortization of deferred gain from sale-leaseback	(8,469)	(11,828)	(11,828)
Amortization of corporate-owned life insurance	16,265	12,622	14,320
Non-cash stock compensation	3,219	7,916	6,885
Net changes in energy marketing assets and liabilities	5,799	4,383	(1,855)
Loss on extinguishment of debt and settlement of putable/callable notes	—	18,840	26,455
Net changes in fair value of call option	—	—	2,178
Gain on sale of ONEOK, Inc. stock	—	—	(99,327)
Accrued liability to certain former officers	2,018	8,384	1,205
Gain on sale of utility plant and property	—	(503)	(11,912)
Net deferred income taxes and credits	25,552	(5,215)	(100,275)
Changes in working capital items, net of acquisitions and dispositions:			
Accounts receivable, net	(32,179)	(11,561)	(32,031)
Inventories and supplies	22,745	10,368	8,607
Prepaid expenses and other	(65,635)	(35,114)	6,426
Accounts payable	6,929	6,439	6,072
Accrued taxes	91,938	43,463	81,135
Other current liabilities	(20,876)	(5,907)	(84,793)
Changes in other, assets	20,374	12,846	1,783
Changes in other, liabilities	(12,492)	6,880	(7,066)
Cash flows from operating activities	353,891	345,624	148,540
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(212,814)	(197,149)	(163,314)
Purchase of securities within the nuclear decommissioning trust fund	(372,426)	(313,241)	(235,890)
Sale of securities within the nuclear decommissioning trust fund	367,570	309,105	228,737
Investment in corporate-owned life insurance	(19,346)	(19,658)	(19,599)
Proceeds from investment in corporate-owned life insurance	10,997	—	—
Proceeds from sale of Protection One, Inc.	—	81,670	—
Proceeds from sale of Protection One, Inc. bonds	—	26,640	—
Proceeds from sale of plant and property	—	8,604	33,303
Proceeds from sale of international investment	—	11,219	—
Proceeds from sale of ONEOK, Inc. stock	—	—	801,841
Issuance of officer loans and interest, net of payments	—	2	438
Proceeds from other investments	13,990	16,548	9,893
Cash flows (used in) from investing activities	(212,029)	(76,260)	655,409
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	—	(1,000)	—
Proceeds from long-term debt	642,807	623,301	—
Retirements of long-term debt	(741,847)	(1,188,081)	(963,330)
Funds in trust for debt repayments	—	78	145,182
Purchase of call option investment	—	—	(65,785)
Repayment of capital leases	(4,898)	(4,977)	(5,138)
Borrowings against cash surrender value of corporate-owned life insurance	58,039	57,090	58,818
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(13,026)	(444)	(419)
Issuance of common stock, net	5,584	245,130	—
Cash dividends paid	(74,593)	(56,189)	(57,726)
Reissuance of treasury stock	—	1,927	7,260
Cash flows used in financing activities	(127,934)	(323,165)	(881,138)
CASH FLOWS FROM (USED IN) DISCONTINUED OPERATIONS:			
Cash flows from operating activities	—	2,265	82,384
Cash flows used in investing activities	—	(3,412)	(28,882)
Cash flows used in financing activities	—	—	(9,803)
Net cash (used in) from discontinued operations	—	(1,147)	43,699
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	13,928	(54,948)	(33,490)
CASH AND CASH EQUIVALENTS:			
Beginning of period	24,611	79,559	113,049
End of period	$ 38,539	$ 24,611	$ 79,559

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

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

	Year Ended December 31,					
	2005		2004		2003	
	Shares	Amount	Shares	Amount	Shares	Amount
Cumulative preferred stock	214,363	$ 21,436	214,363	$ 21,436	214,363	$ 21,436
Common stock:						
Beginning balance	86,029,721	430,149	72,840,217	364,201	72,840,217	364,201
Issuance of common stock	805,650	4,028	13,189,504	65,948	—	—
Ending balance	86,835,371	434,177	86,029,721	430,149	72,840,217	364,201
Paid-in capital:						
Beginning balance		912,932		776,754		825,744
Preferred dividends, net of retirements		—		653		728
Issuance of common stock, net		13,171		192,337		—
Dividends on common stock		—		(46,473)		(53,501)
Issuance of treasury stock		—		1,230		671
Grant of restricted stock		2,986		1,417		7,631
Stock compensation		(6,006)		(12,986)		(4,519)
Ending balance		923,083		912,932		776,754
Unearned compensation:						
Beginning balance		(10,361)		(15,879)		(14,742)
Grant of restricted stock		(2,986)		(1,417)		(7,631)
Amortization of restricted stock		3,019		6,838		6,494
Forfeited restricted stock		71		97		—
Ending balance		(10,257)		(10,361)		(15,879)
Loans to officers:						
Beginning balance		—		(2)		(1,832)
Issuance of officer loans and interest, net of payments		—		2		438
Reclass loans of former officers to other assets		—		—		1,392
Ending balance		—		—		(2)
Retained earnings (accumulated deficit):						
Beginning balance		55,053		(102,782)		(185,961)
Net income		135,610		178,870		85,010
Preferred dividends, net of retirements		(970)		(1,074)		(1,696)
Dividends on common stock		(79,706)		(19,786)		—
Issuance of treasury stock		—		(175)		(135)
Ending balance		109,987		55,053		(102,782)
Treasury stock:						
Beginning balance	—	—	(203,575)	(2,391)	(1,333,264)	(18,704)
Issuance of treasury stock	—	—	203,575	2,391	1,129,689	16,313
Ending balance	—	—	—	—	(203,575)	(2,391)
Accumulated other comprehensive (loss) income:						
Beginning balance		113		(4,577)		(9,502)
Unrealized gain on marketable securities		45		11		102
Unrealized gain on cash flow hedges		—		—		7,727
Minimum pension liability adjustment		(68,321)		7,769		284
Income tax benefit (expense)		27,176		(3,090)		(3,188)
Ending balance		(40,987)		113		(4,577)
Total Shareholders' Equity		$1,437,439		$1,409,322		$1,036,760

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 660,000 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 for which we maintain controlling interests. Common stock investments that are not majority owned are accounted for using the equity method when our investment allows us the ability to exert significant influence. Undivided interests in jointly-owned generation facilities are included on a proportionate basis. All material 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, income taxes, pension and other post-retirement and post-employment benefits, our asset retirement obligations including decommissioning of Wolf Creek, environmental issues, contingencies and litigation. Actual results may differ from those estimates under different assumptions or conditions.

Regulatory Accounting

We currently 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 obligations to make refunds to customers for previous collections of costs that are not likely to be incurred in the future. Regulatory assets and liabilities reflected on our consolidated balance sheets are as follows.

	As of December 31,	
	2005	2004
	(In Thousands)	
Amounts due from customers for future income taxes, net	$166,632	$191,597
Debt reacquisition costs	103,563	45,203
Deferred employee benefit costs	4,160	39,727
Disallowed plant costs	16,929	27,979
2002 ice storm costs	19,389	17,774
2005 ice storm costs	30,878	—
Asset retirement obligations	18,686	—
Depreciation	49,894	22,596
Property taxes	10,462	9,632
Wolf Creek outage	9,915	6,467
Other regulatory assets	6,990	4,620
Total regulatory assets	$437,498	$365,595
Fuel supply contracts	$117,668	$ —
Nuclear decommissioning	16,048	13,745
State Line purchased power	8,109	—
Other regulatory liabilities	20,668	17,274
Total regulatory liabilities	$162,493	$ 31,019

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

- **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. 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. These items are measured by the expected cash flows to be received or settled through future rates. The net regulatory asset for these tax items is classified above as amounts due from customers for future income taxes.
- **Debt reacquisition costs:** Includes costs incurred to reacquire and refinance debt. Debt reacquisition costs are amortized over the term of the new debt.

- **Deferred employee benefit costs:** Deferred employee benefit costs represent post-retirement and post-employment expenses in excess of amounts paid that are to be recovered over a period of five years.
- **Disallowed plant costs:** In 1985, the 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. See Note 3, "Rate Matters and Regulation," for additional information.
- **2002 ice storm costs:** We accumulated and deferred for recovery costs related to system restoration from an ice storm that occurred in January 2002. We were authorized to accrue carrying costs on this item. As allowed by the December 28, 2005 Kansas Corporation Commission (KCC) Order, beginning in 2006 Westar Energy will recover $7.7 million over a three year period and KGE will recover $11.7 million over a five year period. We earn a return on this asset.
- **2005 ice storm costs:** We accumulated and deferred for future recovery costs related to system restoration from an ice storm that occurred in January 2005. We were authorized to accrue carrying costs on this item. As allowed by the December 28, 2005 KCC Order, beginning in 2006 Westar Energy will recover $5.6 million over a three year period and KGE will recover $25.3 million over a five year period. We earn a return on this asset.
- **Asset retirement obligations:** Represents amounts associated with our asset retirement obligations as discussed in Note 15, "Asset Retirement Obligations." We recover this item over the life of the utility plant.
- **Depreciation:** Represents the difference between the KCC allowed depreciation expense and the depreciation expense recorded for financial statement purposes. The increase in the depreciation regulatory asset is due primarily to recognizing differences in depreciation from August 2001 to March 2002 pursuant to the December 28, 2005 KCC Order. We earn a return on this asset. We recover this item over the life of the related utility plant.
- **Property taxes:** Represents unrecovered property taxes as allowed by the KCC. We have a recovery period of one year on this item.
- **Wolf Creek outage:** Represents maintenance costs incurred in our most recent refueling outage. In accordance with regulatory treatment, this amount is amortized to expense ratably over the 18-month period after the outage.
- **Other regulatory assets:** This includes various regulatory assets that individually are relatively small in relation to the total regulatory asset balance. Other regulatory assets have various recovery periods, most of which range from one to five years.

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

- **Fuel supply contracts:** Represents the non-cash net gain position on fuel supply contracts that are marked-to-market in accordance with the requirements of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." This net gain will flow back to customer through the terms of the RECA as we take delivery under each contract.

- **Nuclear decommissioning:** Represents amounts received from customers to fund our legal obligation to decommission Wolf Creek. We recover decommissioning costs in rates as provided by the KCC. We have placed amounts recovered in a trust. See Note 15, "Asset Retirement Obligations," for information regarding our Nuclear Decommissioning Trust Fund. The recovery period is through the expiration of Wolf Creek's operating license in 2025.
- **State Line purchased power:** Represents amounts received from customers in excess of costs incurred under Westar Energy's purchased power agreement with Westar Generating, Inc., a wholly owned subsidiary.
- **Other regulatory liabilities:** 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 highly liquid investments with maturities of three months or less when purchased to be cash equivalents.

Restricted Cash

Restricted cash consists of cash irrevocably deposited in trust for a prepaid capacity and transmission agreement, surety bonds and power marketing contracts.

Inventories and Supplies

Inventories and supplies are stated at average cost.

Property, Plant and Equipment

Property, plant and equipment is stated 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 cost of borrowed funds used to finance construction projects. The AFUDC rate was 4.2% in 2005, 3.8% in 2004 and 5.3% in 2003. The cost of additions to utility plant and replacement units of property is capitalized. AFUDC capitalized was $2.7 million in 2005, $1.8 million in 2004 and $1.5 million in 2003.

Maintenance costs and replacement of minor items of property are charged to expense as incurred. Normally, when a unit of depreciable property is retired, the original cost, less salvage value, is charged to accumulated depreciation.

Depreciation

Utility plant is depreciated on a straight-line method at rates based on the estimated remaining useful lives of the assets, which are based on an average annual composite basis using group rates that approximated 2.5% in 2005, 2.6% in 2004 and 2.5% in 2003.

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

	Years
Fossil fuel generating facilities	6 to 68
Nuclear fuel generating facility	38 to 40
Transmission facilities	28 to 67
Distribution facilities	19 to 57
Other	5 to 55

In its order on December 28, 2005, the KCC approved a change in our depreciation rates allowing for inclusion of net salvage costs, which include the ultimate cost of dismantlement of plant facilities. This change, along with other changes in estimated useful lives, will result in an annual increase in the recovery of depreciation expense of approximately $27.6 million.

Nuclear Fuel

Our share of the cost of nuclear fuel used in the process of refinement, conversion, enrichment and fabrication is recorded as an asset in property, plant and equipment on our consolidated balance sheets at original cost and is amortized to fuel and purchased power 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 $24.2 million at December 31, 2005 and $30.9 million at December 31, 2004. Spent nuclear fuel charged to fuel and purchased power was $18.0 million in 2005, $19.3 million in 2004 and $17.0 million in 2003.

Cash Surrender Value of Life Insurance

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

	As of December 31,	
	2005	2004
	(In Thousands)	
Cash surrender value of policies	$1,014,198	$ 967,485
Borrowings against policies	(936,329)	(891,320)
Corporate-owned life insurance, net	$ 77,869	$ 76,165

Income is recorded for increases in cash surrender value and death proceeds. Interest incurred on amounts borrowed is offset against policy income. Income recognized from death proceeds is highly variable from period to period. Death benefits recognized as income on our consolidated statements of income approximated $9.5 million in 2005, $2.0 million in 2004 and $1.8 million in 2003.

Revenue Recognition – Energy Sales

We recognize revenues from retail energy sales upon delivery to the customer and include an estimate for energy delivered but unbilled. Our estimate of revenue attributable to this unbilled portion is based on the total energy available for sale measured against billed sales. At December 31, 2005, we had estimated unbilled revenue of $42.1 million.

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 fuel contracts, 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 are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. Prices used to value these transactions reflect our best estimate of fair values of our trading positions.

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.

Dilutive Shares

Basic earnings per share applicable to equivalent common stock are 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 include 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 additional issuance of shares under the employee stock purchase plan (ESPP). We discontinued the ESPP effective January 1, 2005. The dilutive effect of shares issuable under the ESPP and our stock-based compensation plans is computed 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,		
	2005	2004	2003
DENOMINATOR FOR BASIC AND DILUTED EARNINGS PER SHARE:			
Denominator for basic earnings per share – weighted average equivalent shares	86,855,485	82,941,374	72,428,728
Effect of dilutive securities:			
Employee stock purchase plan shares	—	17,515	113,737
Employee stock options	1,750	1,943	305
Restricted share units	552,423	680,216	924,978
Denominator for diluted earnings per share – weighted average shares	87,409,658	83,641,048	73,467,748
Potentially dilutive shares not included in the denominator because they are antidilutive	214,340	217,375	217,375

Table of Contents

Stock Based Compensation

For purposes of the pro forma disclosures required by SFAS No. 148, "Accounting for Stock Based Compensation – Transition and Disclosure," the estimated fair value of stock options is amortized to expense over the relevant vesting period. Information related to the pro forma impact on our consolidated earnings and earnings per share follows.

	Year Ended December 31,		
	2005	2004	2003
	(Dollars In Thousands, Except Per Share Amounts)		
Earnings available for common stock, as reported	$ 134,640	$ 177,900	$ 84,042
Add: Effect of stock-based compensation included in earnings available for common stock, as reported, net of related tax effects	(3)	294	46
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	5	757	2,615
Earnings available for common stock, pro forma	$ 134,632	$ 177,437	$ 81,473
Weighted average shares used for dilution	87,409,658	83,641,048	73,467,748
Earnings per share:			
Basic – as reported	$ 1.55	$ 2.14	$ 1.16
Basic – pro forma	$ 1.55	$ 2.14	$ 1.12
Diluted – as reported	$ 1.54	$ 2.13	$ 1.14
Diluted – pro forma	$ 1.54	$ 2.12	$ 1.11

Supplemental Cash Flow Information

	Year Ended December 31,		
	2005	2004	2003
	(In Thousands)		
CASH PAID FOR:			
Interest on financing activities, net of amount capitalized	$87,634	$127,993	$208,174
Income taxes	772	1,162	53,625
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and RSUs	11,728	14,674	9,505
Assets acquired through capital leases	3,716	3,272	1,252

New Accounting Pronouncement – Accounting Changes and Error Corrections

On May 30, 2005, the Financial Accounting Standards Board (FASB) issued SFAS No. 154, "Accounting Changes and Error Corrections – Replacement of APB 20 and SFAS No. 3," which changes the requirements for the accounting and reporting of a change in accounting principle. SFAS No. 154 applies to all voluntary changes in accounting principle as well as to changes required by an accounting pronouncement that does not include specific transition provisions. For most accounting changes and error corrections, SFAS No. 154 requires retrospective application, under which the new accounting principle is applied as of the beginning of the first period presented as if that principle had always been used. SFAS No. 154 is effective for accounting changes and corrections of errors made beginning January 1, 2006.

Reclassifications and Revisions

We have reclassified and revised certain prior year amounts to conform with classifications used in the current-year presentation as necessary for a fair presentation of the financial statements.

We previously presented our asset retirement obligation associated with Wolf Creek as a regulatory asset. We have reclassified this amount to offset amounts collected from customers that were previously recorded as nuclear decommissioning accrual.

We have revised the prior years' presentation of our consolidated statements of cash flows to separately present the cash flows of discontinued operations from operating, investing and financing activities. The presentation of investments in and proceeds from purchases and sales of marketable securities in our nuclear decommissioning trust is on a gross basis, rather than net, and the presentation of changes in restricted cash as an investing activity rather than an operating activity. Accordingly, we reclassified restricted cash included in cash flows from operating activities to proceeds from other investments in cash flows used in investing activities in the amount of $2.9 million and $1.9 million for the years ended December 31, 2004 and 2003, respectively. In addition, we revised the cash flows associated with construction work in progress that had not been paid as of year-end. As a result, we reclassified $5.7 million and $0.2 million for the years ended December 31, 2004 and 2003, respectively, to cash flows from operating activities, from additions to property, plant and equipment in cash flows used in investing activities.

3. RATE MATTERS AND REGULATION

Retail Rate Review

December 28, 2005 KCC Order

In accordance with a 2003 KCC order, we filed applications with the KCC on May 2, 2005 to review our rates. We requested an increase in our retail electric rates and the adoption of other practices under the KCC's jurisdiction. While the KCC ordered a net increase in our base rates of $38.8 million annually, the increase is substantially offset by the requirement that we credit to retail customers a rolling three-year average of the margins we realize from our market-based wholesale sales. Other significant changes approved by the KCC are a retail energy cost adjustment (RECA), an environmental cost recovery rider (ECRR), the separation of transmission delivery charges, an increase in annual depreciation expense, an extended recovery period for costs being recovered for which no return is provided and the recovery of various costs that have been incurred and deferred as regulatory assets.

Retail Energy Cost Adjustment: The RECA allows us to recover the actual cost of fuel consumed in producing electricity and the cost of purchased power. The adjustment is based on the actual cost of fuel and purchased power less margins from market-based wholesale sales. We have contracts with certain large industrial customers, the terms of which do not provide for the separate billing of fuel costs. Fuel costs for these customers will continue to be recovered through the rates specified in each of these contracts. These customers represented approximately 8% of our total retail sales volumes for 2005.

Wholesale Sales Margins: The terms of the RECA require that we include, as a credit to recoverable fuel costs, an amount based on the average of the margins realized from market-based wholesale sales during the immediately prior three-year period. In any period we are unable to realize market-based wholesale sales margins at least equal to the amount of the credit, our financial results would be adversely affected. In the short-term, our generating capacity is fixed while the load requirements of our customers change constantly. When our generating capacity is not needed to serve our customers, we attempt to seek out wholesale sales of energy at prices in excess of the costs of production. We are likely to face the prospect of decreasing margins as the energy demands of our retail customers increase, which may result in crediting to retail customers an amount that would exceed the margins realized in the current period.

Environmental Cost Recovery Rider: The ECRR allows for the timely inclusion in rates, without requiring a full rate review, of the capital expenditures made to upgrade our equipment to meet stricter environmental standards required by the Clean Air Act. Prior to collection through rates, the KCC will review any environmental expenditures to be considered for recovery under the ECRR. Any increased operating and maintenance costs that result from updating or adding environmental equipment cannot be recovered through the ECRR. These costs would be addressed in future rate reviews.

Transmission Delivery Charge: The December 28, 2005 KCC Order allows us to separate our transmission costs from our base rates charged to retail customers. This allows us to implement a formula transmission rate that provides for annual adjustments to reflect changes in our transmission costs, which provides for adjustment on a more timely basis. These rates were proposed in an application filed with FERC on May 2, 2005 and became effective on December 1, 2005, subject to refund upon review and approval by FERC.

Depreciation Rates: The December 28, 2005 KCC Order authorized an annual increase in the recovery of depreciation expense of approximately $27.6 million. The approved change in depreciation rates allows for the inclusion of net salvage costs, which include an estimate for the cost of dismantlement of plant facilities.

Disallowed Plant Costs: In 1985, the 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 original depreciable life of Wolf Creek, or through 2025, but disallowed any return on these costs. In its December 28, 2005 order, the KCC extended the recovery period to correspond to Wolf Creek's new estimated depreciable life. KGE recognized a loss of $10.4 million in the fourth quarter of 2005 as a result of the decrease in the present value of amounts to be received due to the extension of the recovery period.

Other Regulatory Assets: The December 28, 2005 KCC Order also approved for recovery approximately $50.3 million of deferred maintenance costs associated with restoring utility service to our customers stemming from damage to our lines and equipment in the ice storms that occurred in 2002 and 2005 and various other expenses that are relatively small in relation to the total regulatory asset balance.

FERC Proceedings

Request for Change in Transmission Rates

On May 2, 2005, we filed applications with FERC that propose a formula transmission rate that provides for annual adjustments to reflect changes in our transmission costs. This is consistent with our proposals filed with the KCC on May 2, 2005 to separately charge retail customers for transmission service. These rates became effective on December 1, 2005, subject to refund. We can provide no assurance that FERC will ultimately approve our applications as filed.

Market-based Rates

On March 23, 2005, FERC instituted a proceeding concerning the reasonableness of our market-based rates in our electric control area and the electrical control areas of Midwest Energy, Inc. and Aquila, Inc.'s West Plains Energy division. We have provided FERC with information it requested for its analysis. A FERC decision, anticipated in 2006, could affect how we price future wholesale power sales to wholesale customers in our control area and to Midwest Energy and West Plains Energy and wholesale customers in their control areas. We do not expect the outcome of this matter to significantly impact our consolidated results of operations.

4. ACCOUNTS RECEIVABLE SALES PROGRAM

We sell our accounts receivable, without recourse, to WR Receivables Corporation, a wholly owned subsidiary. WR Receivables may sell up to $125.0 million of an undivided interest in this pool of receivables to a bank and commercial paper conduit pursuant to an agreement entered into in 2000. We renewed the agreement in July 2005 for one year on terms substantially similar to the expiring agreement. This transaction constitutes a sale of receivables in accordance with SFAS No. 140. WR Receivables has no ownership interest in the bank or commercial paper conduit and is not required to consolidate these entities in accordance with GAAP.

The receivables sold by WR Receivables to the bank and commercial paper conduit are not reflected in the accounts receivable balance in the accompanying consolidated balance sheets. The amounts sold to the bank and commercial paper conduit were $65.0 million at December 31, 2005 and $80.0 million at December 31, 2004. We record this activity on the consolidated statements of cash flows in the “accounts receivable, net” line of cash flows from operating activities.

We service, administer and collect the receivables on behalf of the bank and commercial paper conduit. WR Receivables incurred a loss on the sale of the accounts receivable sold to the commercial paper conduit of $3.3 million in 2005, $2.1 million in 2004 and $2.4 million in 2003. We include this loss in other expense on our consolidated statements of income.

We record the sale of receivables to WR Receivables at book value, net of allowance for bad debts. This approximates fair value due to the short-term nature of the receivables. We include the accounts receivables retained by WR Receivables in accounts receivable, net, on our consolidated balance sheets.

The following table summarizes comparative accounts receivable information for WR Receivables.

	As of December 31,	
	2005	2004
	(In Thousands)	
Proceeds from the sale of accounts receivables	$ 1,034,459	$ 1,041,258
Loss on sale of accounts receivables	3,339	2,114
Accounts receivable retained interest and pledged as collateral less uncollectible accounts	19,956	10,023
Retained interest if 10% adverse change in uncollectible accounts	19,794	9,792
Retained interest if 20% adverse change in uncollectible accounts	19,629	9,559

The following table shows the historical loss and delinquency amounts for the customer accounts receivable managed portfolio.

	As of December 31,	
	2005	2004
	(In Thousands)	
Customer accounts receivable	$128,868	$ 97,017
Allowance for uncollectible accounts	(4,933)	(5,152)
Customer accounts receivable, net	123,935	91,865
Other accounts receivable	1,076	828
Other allowance for uncollectible accounts	(300)	(161)
Total balance sheet accounts receivable, net	124,711	92,532
Customer accounts receivable sold	65,000	80,000
Total accounts receivable managed	$189,711	$172,532
Net uncollectible accounts written off	$ 3,862	$ 2,751
Delinquent customer accounts receivable over 60 days	$ 2,994	$ 2,939

Table of Contents

5. FINANCIAL INSTRUMENTS, ENERGY MARKETING AND RISK MANAGEMENT

Values of Financial Instruments

We estimate the fair value of each class of our financial instruments for which it is practicable to estimate that value as set forth in SFAS No. 107, "Disclosures about Fair Value of Financial Instruments."

Cash and cash equivalents, short-term borrowings and variable-rate debt are carried at cost, which approximates fair value. The nuclear decommissioning trust is recorded at fair value, which is estimated based on the quoted market prices at December 31, 2005 and 2004. See Note 6, "Financial Investments and Trading Securities," for additional information about our nuclear decommissioning trust. The fair value of fixed-rate debt is estimated 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 fair value estimates are based on information available at December 31, 2005 and 2004. These fair value estimates have not been comprehensively revalued for the purpose of these financial statements since that date and current estimates of fair value may differ from the amounts below. The carrying values and estimated fair values of our financial instruments are as shown in the table below.

	Carrying Value		Fair Value	
	As of December 31,			
	2005	2004	2005	2004
	(In Thousands)			
Fixed-rate debt, net of current maturities	$1,344,406	$1,419,406	$1,339,452	$1,530,035

Derivative Instruments and Hedge Accounting

We are exposed to market risks from changes in commodity prices and interest rates that could affect our consolidated results of operations and financial condition. We manage our exposure to these market risks through our regular operating and financing activities and, when deemed 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 and prudent business 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, oil, coal and electricity. We classify derivative instruments used 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 trade electricity, coal, natural gas and oil. We use a variety of financial instruments, including forward 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 to take advantage of market trends and conditions. With the exception of fuel contracts, we reflect changes in value 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 selected market opportunities. We refer to these transactions as energy marketing activities.

We are involved in trading activities 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 position or results of operations.

We have considered a number of risks and costs associated with the future contractual commitments included 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 also exposed to commodity price changes. We use derivative contracts for non-trading purposes and a mix of various fuel types primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power market is 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 fossil fuel types, including coal, natural gas and oil, to operate our plants. A significant portion of our coal requirements are purchased under long-term contracts. Due to the volatility of natural gas prices, we have increasingly operated facilities that have allowed us to use lower cost fuel types as generating unit constraints and environmental restrictions allow, primarily by using oil in our facilities that also burn natural gas.

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 used for generation vary from year to year based on availability, price and deliverability of a given fuel type as well as planned and scheduled 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 price risk management activities reflect our estimate of fair values considering various factors, including closing exchange and over-the-counter 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.

Hedging Activities

During the third quarter of 2001, we entered into hedging relationships to manage commodity price risk associated with future natural gas purchases. Initially, we entered into futures and swap contracts with terms extending through July 2004 to hedge price risk for a portion of our anticipated natural gas fuel requirements for our generation facilities. We designated these hedging relationships as cash flow hedges.

In 2002, due to the increased availability of our coal units and because we began burning more oil as use of oil became more economically favorable than natural gas, we did not burn our forecasted amount of natural gas. In September 2002, we determined that we had over-hedged approximately 12,000,000 MMBtu for the remaining period of the hedge. As a result of the discontinuance of this portion of the cash flow hedge, we recognized a gain of $4.0 million. In December 2003, we determined we could no longer meet the criteria to use hedge accounting for the 2004 forecasted natural gas purchases. As a result, we recognized in income a gain of $3.7 million, of which $2.8 million had previously been recognized in other comprehensive income.

Effective October 4, 2001, we entered into a $500.0 million interest rate swap agreement with a term of two years. At that time, the effect of the swap agreement was to fix the annual interest rate on a term loan at 6.18%. We settled the swap agreement for a nominal amount on September 29, 2003.

In the second quarter of 2003, we purchased a call option at a cost of $65.8 million, which locked in a settlement cost associated with a call option entered into in 1998 related to our 6.25% putable/callable notes. We settled the call option in August 2003.

6. 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 investments in trust assets securing certain executive benefits that are classified as trading securities. We include any unrealized gains or losses on these securities in investment earnings on our consolidated statements of income. The unrealized loss at December 31, 2005 was $0.3 million and the unrealized gain at December 31, 2004 was $1.1 million.

Available-for-Sale Securities

We have investments in debt and equity securities that are held in trust funds for the purpose of funding the decommissioning of our Wolf Creek nuclear plant. We have classified these investments in debt and equity securities as available-for-sale and have recorded all such investments at their fair market value at December 31, 2005 and 2004. Investments by the nuclear decommissioning trust fund are allocated 66% to equity securities, with the balance invested in fixed-income securities, cash and cash equivalents. Fixed-income investments are limited to U.S. government or agency securities, municipal bonds, or investment-grade corporate securities. Using the specific identification method to determine cost, the gross realized gains on those sales were $3.2 million for 2005, $4.3 million for 2004 and $1.9 million for 2003. Net realized and unrealized gains and losses are reflected in regulatory liabilities on our consolidated balance sheets. This reporting is consistent with the method we use to account for the decommissioning costs recovered in rates. Gains or losses on assets in the trust fund could result in lower or higher funding requirements for decommissioning costs, which we believe would be recovered in electric rates paid by our customers.

The following table presents the costs and fair values of investments in debt and equity securities in the nuclear decommissioning trust fund at December 31, 2005 and 2004. Changes in the fair value of the trust fund are recorded as an increase or decrease to the regulatory liability recorded in connection with the decommissioning of Wolf Creek.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
	(In Thousands)			
2005:				
Debt securities	$25,196	$ —	$(309)	$ 24,887
Equity securities	51,591	14,731	—	66,322
Cash equivalents	9,594	—	—	9,594
Total	$86,381	$14,731	$(309)	$100,803
2004:				
Debt securities	$28,574	$ 6	$ —	$ 28,580
Equity securities	46,566	12,224	—	58,790
Cash equivalents	3,725	—	—	3,725
Total	$78,865	$12,230	$ —	$ 91,095

The following table presents the costs and fair values of investments in debt securities in the nuclear decommissioning trust fund at December 31, 2005 according to their contractual maturities.

	Cost	Fair Value
	(In Thousands)	
Less than 5 years	$ 6,438	$ 6,325
5 years to 10 years	6,770	6,722
Due after 10 years	11,988	11,840
Total	$25,196	$ 24,887

Marketable Securities

On January 1, 2003, we classified our investment in ONEOK as an available-for-sale security. During 2003, we sold our investment in ONEOK and recorded a pre-tax gain of $99.3 million. There were no sales of marketable securities during 2005 or 2004. During 2003, sales proceeds from marketable securities were $801.8 million and we realized a gain of $99.3 million on these sales.

7. PROPERTY, PLANT AND EQUIPMENT

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

	As of December 31, 2005	As of December 31, 2004
	(In Thousands)	
Electric plant in service	$ 5,937,760	$ 5,777,519
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(2,880,613)	(2,761,781)
	3,859,465	3,818,056
Construction work in progress	60,561	56,910
Nuclear fuel, net	27,672	35,942
Net utility plant	3,947,698	3,910,908
Non-utility plant in service	34	79
Net property, plant and equipment	$ 3,947,732	$ 3,910,987

Depreciation expense on property, plant and equipment for the years ended December 31, 2005, 2004 and 2003 was as follows.

	Year Ended December 31, 2005	2004	2003
	(In Thousands)		
Utility	$130,146	$148,933	$147,015
Non-utility	—	—	10
Total depreciation expense	$130,146	$148,933	$147,025

8. 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. Information relative to our ownership interest in these facilities at December 31, 2005 is shown in the table below.

		Our Ownership at December 31, 2005				
		In-Service Dates	Investment	Accumulated Depreciation	Net MW	Ownership Percent
			(Dollars in Thousands)			
La Cygne unit 1	(a)	June 1973	$ 219,638	$ 121,532	362.0	50
Jeffrey unit 1	(b)	July 1978	323,452	164,724	618.0	84
Jeffrey unit 2	(b)	May 1980	311,906	149,513	617.0	84
Jeffrey unit 3	(b)	May 1983	437,069	206,658	622.0	84
Jeffrey wind 1	(b)	May 1999	874	274	0.6	84
Jeffrey wind 2	(b)	May 1999	874	274	0.6	84
Wolf Creek	(c)	Sept. 1985	1,427,947	612,824	548.0	47
State Line	(d)	June 2001	108,096	19,481	200.0	40

(a) Jointly owned with Kansas City Power & Light Company (KCPL)
(b) Jointly owned with Aquila, Inc.
(c) Jointly owned with KCPL and Kansas Electric Power Cooperative, Inc.
(d) Jointly owned with Empire District Electric Company

Amounts and capacity presented above represent our share. Our share of operating expenses of the above plants, as well as such expenses for a 50% undivided interest in La Cygne unit 2 (representing 337 megawatt (MW) capacity) sold and leased back to KGE in 1987, are included in operating expenses on our consolidated statements of income. Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

9. SHORT-TERM DEBT

A syndicate of banks provides us a revolving credit facility on a committed basis totaling $350.0 million. The facility is secured by KGE’s first mortgage bonds and matures on May 6, 2010. It allows us to borrow up to an aggregate amount of $350.0 million, including letters of credit up to a maximum aggregate amount of $100.0 million. So long as there is no default or event of default under the revolving credit facility, Westar Energy may elect, subject to lender participation, to increase the aggregate amount of borrowings under this facility to $500.0 million. At December 31, 2005, we had no outstanding borrowings and $48.0 million of letters of credit outstanding under this facility.

Information regarding our short-term borrowings is as follows.

	As of December 31, 2005	2004
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$ 9,661	$ 1,434
Weighted daily average interest rates during the year, excluding fees	4.77%	3.50%

Our interest expense on short-term debt was $1.3 million in 2005, $1.1 million in 2004 and $1.2 million in 2003.

10. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

	As of December 31, 2005	2004
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
7.875% due 2007	$ —	$ 365,000
6.000% due 2014	250,000	250,000
5.150% due 2017	125,000	—
5.950% due 2035	125,000	—
5.100% due 2020	250,000	—
5.875% due 2036	150,000	—
	900,000	615,000
Pollution control bond series:		
Variable due 2032, 3.30% at December 31, 2005; 1.95% at December 31, 2004	45,000	45,000
Variable due 2032, 3.20% at December 31, 2005; 2.00% at December 31, 2004	30,500	30,500
5.000% due 2033	58,340	58,340
	133,840	133,840
9.750% unsecured senior notes due 2007	—	260,000
7.125% unsecured senior notes due 2009	145,078	145,078
	145,078	405,078
KGE		
First mortgage bond series:		
6.500% due 2005	—	65,000
6.200% due 2006	100,000	100,000
	100,000	165,000
Pollution control bond series:		
5.100% due 2023	13,488	13,488
Variable due 2027, 3.35% at December 31, 2005; 1.75% at December 31, 2004	21,940	21,940
5.300% due 2031	108,600	108,600
5.300% due 2031	18,900	18,900
2.650% due 2031 and putable 2006	100,000	100,000
Variable due 2031, 3.49% at December 31, 2005; 1.92% at December 31, 2004	100,000	100,000
Variable due 2032, 3.30% at December 31, 2005; 1.76% at December 31, 2004	14,500	14,500
Variable due 2032, 3.25% at December 31, 2005; 1.85% at December 31, 2004	10,000	10,000
	387,428	387,428
Unamortized debt discount (a)	(3,356)	(1,445)
Long-term debt due within one year	(100,000)	(65,000)
Long-term debt, net	$1,562,990	$1,639,901

(a) We amortize debt discount 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. Therefore, we must ensure that we will be able to 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. At December 31, 2005, based on an assumed interest rate of 6%, no additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage. At December 31, 2005, based on an assumed interest rate of 6%, approximately $607.3 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

On January 17, 2006, KGE repaid the outstanding $100.0 million aggregate principal amount of KGE 6.2% first mortgage bonds with cash on hand and borrowings under the Westar Energy revolving credit facility. On August 1, 2005, KGE repaid the outstanding $65.0 million aggregate principal amount of KGE 6.5% first mortgage bonds with cash on hand and borrowings under the Westar Energy revolving credit facility.

On June 30, 2005, Westar Energy sold $400.0 million aggregate principal amount of Westar Energy first mortgage bonds, consisting of $150.0 million of 5.875% bonds maturing in 2036 and $250.0 million of 5.1% bonds maturing in 2020. On July 27, 2005, proceeds from the offering were used to redeem the outstanding $365.0 million aggregate principal amount of Westar Energy's 7.875% first mortgage bonds due 2007, together with accrued interest and a call premium equal to approximately 6% of the principal outstanding, and for general corporate purposes. The call premium is recorded as a regulatory asset and is being amortized over the term of the new bonds.

On May 6, 2005, Westar Energy amended its revolving credit facility dated March 12, 2004 to extend the term and reduce borrowing costs. The amended revolving credit facility matures on May 6, 2010. The facility is used as a source of short-term liquidity. It allows us to borrow up to an aggregate amount of $350.0 million, including letters of credit up to a maximum aggregate amount of $100.0 million. So long as there is no default or event of default under the revolving credit facility, Westar Energy may elect, subject to lender participation, to increase the aggregate amount of borrowings under this facility to $500.0 million. All borrowings under the revolving credit facility are secured by KGE first mortgage bonds.

On January 18, 2005, Westar Energy sold $250.0 million aggregate principal amount of Westar Energy first mortgage bonds, consisting of $125.0 million 5.15% bonds maturing in 2017 and $125.0 million 5.95% bonds maturing in 2035. On February 17, 2005, we used the net proceeds from the offering, together with cash on hand, additional funds raised through the accounts receivable conduit facility and borrowings under Westar Energy's revolving credit facility, to redeem the remaining $260.0 million aggregate principal amount of Westar Energy 9.75% senior notes due 2007. Together with accrued interest and a premium equal to approximately 12% of the outstanding senior notes, we paid $298.5 million to redeem the Westar Energy 9.75% senior notes due 2007. The call premium is recorded as a regulatory asset and is being amortized over the term of the new bonds.

On June 10, 2004, KGE refinanced $327.5 million of pollution control bonds. The original issue had an interest rate of 7% and was due in 2031. This issue was replaced with pollution control bonds at interest rates of 5.3% on $127.5 million that matures in 2031, 2.65% on $100.0 million that matures in 2031, and a variable rate on $100.0 million that matures in 2031.

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 at December 31, 2005.

Maturities

Maturities of long-term debt at December 31, 2005 are as follows.

Year	Principal Amount (In Thousands)
2006	$ 100,000
2007	—
2008	—
2009	145,078
Thereafter	1,417,912
Total long-term debt maturities	$ 1,662,990

Our interest expense on long-term debt was $107.8 million in 2005, $141.1 million in 2004, and $223.2 million in 2003.

Affiliate Long-term Debt and Other Mandatorily Redeemable Securities

On December 14, 1995, Western Resources Capital I, a wholly owned trust, issued $100.0 million of 7-7/8% Cumulative Quarterly Income Preferred Securities, Series A. On April 16, 2004, we redeemed our entire issuance of Western Resources Capital I 7-7/8% Cumulative Quarterly Income Preferred Securities, Series A, at par.

On July 31, 1996, Western Resources Capital II, a wholly owned trust, issued $120.0 million of 8-1/2% Cumulative Quarterly Income Preferred Securities, Series B. On September 22, 2003, we redeemed our entire issuance of Western Resources Capital II 8-1/2% Cumulative Quarterly Income Preferred Securities, Series B, at par.

11. INCOME TAXES

Income tax expense (benefit) is composed of the following components.

	Year Ended December 31, 2005	2004	2003
		(In Thousands)	
Income Tax Expense (Benefit) from Continuing Operations:			
Current income taxes:			
Federal	$30,132	$ 41,649	$ 148,117
State	4,829	(2,991)	33,926
Deferred income taxes:			
Federal	24,831	(2,285)	(78,069)
State	3,511	1,858	(17,564)
Investment tax credit amortization	(2,790)	(4,788)	(4,642)
Income tax expense from continuing operations	60,513	33,443	81,768
Income Tax Expense (Benefit) from Discontinued Operations:			
Current income taxes:			
Federal	29	(116,903)	(63,731)
State	7	(22,569)	(12,402)
Deferred income taxes:			
Federal	370	77,019	(70,492)
State	84	17,172	(17,411)
Income tax expense from discontinued operations	490	(45,281)	(164,036)
Total income tax expense (benefit)	$61,003	$ (11,838)	$ (82,268)

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

	December 31, 2005	December 31, 2004
	(In Thousands)	
Current deferred tax assets	$ 19,211	$ —
Current deferred tax liabilities	—	2,163
Non-current deferred income tax liabilities	911,135	917,706
Net deferred tax liabilities	$891,924	$919,869

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, 2005	December 31, 2004
	(In Thousands)	
Deferred tax assets:		
Deferred gain on sale-leaseback	$ 57,297	$ 61,241
General business credit carryforward (a)	15,679	27,645
Accrued liabilities	20,390	18,803
Disallowed plant costs	16,617	13,484
Long-term energy contracts	10,289	11,194
Capital loss carryforward (b)	227,668	230,226
Other	79,547	74,875
Total gross deferred tax assets	427,487	437,468
Less: Valuation allowance (b)	233,211	236,588
Deferred tax assets	$ 194,276	$ 200,880
Deferred tax liabilities:		
Accelerated depreciation	$ 644,082	$ 659,776
Acquisition premium	235,167	243,165
Amounts due from customers for future income taxes, net	166,632	191,597
Other	40,319	26,211
Total deferred tax liabilities	$1,086,200	$1,120,749
Net deferred tax liabilities	$ 891,924	$ 919,869

(a) Balance represents unutilized tax credits generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These credits expire beginning 2019 through 2025.

(b) As of December 31, 2005, we have a net capital loss of $572.4 million available to offset any future capital gains through 2009. However, as we do not expect to realize any significant capital gains in the future, a valuation allowance of $227.7 million has been established. In addition, a valuation allowance of $5.5 million has been established for certain deferred tax assets related to the write-down of other investments. The total valuation allowance related to deferred tax assets was $233.2 million as of December 31, 2005 and $236.6 million as of December 31, 2004. The net reduction in valuation allowance of $3.4 million was due primarily to capital gains realized in 2005.

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 set forth below are for continuing operations and discontinued operations. The 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,		
	2005	2004	2003
Statutory federal income tax rate from continuing operations	35.0%	35.0%	35.0%
Effect of:			
State income taxes	2.8	1.0	4.3
Amortization of investment tax credits	(1.4)	(3.6)	(1.9)
Corporate-owned life insurance policies	(6.9)	(9.0)	(5.0)
Accelerated depreciation flow through and amortization	1.2	5.3	2.2
Dividends received deduction	—	—	(1.7)
Income tax reserve adjustment	0.6	(5.3)	—
Capital loss utilization	(0.8)	(2.2)	—
Other	0.5	3.8	0.5
Effective income tax rate from continuing operations	31.0%	25.0%	33.4%
Statutory federal income tax rate from discontinued operations	35.0%	35.0%	35.0%
Effect of:			
State income taxes	4.8	(6.4)	8.0
Excess tax basis over book basis in subsidiary investment, net of valuation allowance	—	—	31.0
Election to treat the sale of subsidiary stock as an asset sale	—	(160.6)	—
Valuation allowance adjustment	—	(3.9)	—
Income tax reserve adjustment	—	—	(5.8)
Other	—	0.8	(0.4)
Effective income tax rate from discontinued operations	39.8%	(135.1)%	67.8%

As of December 31, 2005 and 2004, we had recorded reserves for uncertain tax positions of $50.8 million and $49.7 million, respectively. The tax positions may involve income, deductions or credits reported in prior year income tax returns that we believe were treated properly on such tax returns. The tax returns containing these tax reporting positions are currently under audit or will likely be audited by the Internal Revenue Service or other taxing authorities. The timing of the resolution of these audits is uncertain. If the positions taken on the tax returns are ultimately upheld or not challenged within the time available for such challenges, we will reverse these tax provisions to income. If the positions taken on the tax returns are determined to be inappropriate, we may be required to make cash payments for taxes and interest. The reserves are determined based on our best estimate of probable assessments by the applicable taxing authorities and are adjusted, from time to time, based on changing facts and circumstances.

As of December 31, 2005 and 2004, we also had a reserve of $6.1 million and $6.6 million, respectively, for probable assessments of taxes other than income taxes.

12. 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 policy is to fund pension costs accrued, subject to limitations set by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain current and retired officers. Non-union employees hired after December 31, 2001 are covered by the same defined benefit plan with benefits derived from a cash balance account formula.

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 13, "Wolf Creek Employee Benefit Plans" for information about Wolf Creek's benefit plans.

Our pension plan expenses and liabilities are measured using assumptions, which include discount rates, compensation rates and past and future estimated plan asset returns. Due to a decrease in interest rates and a corresponding decrease in the discount rates used to estimate our pension liabilities, the fair value of our pension plan assets was less than the accumulated benefit obligation at our measurement dates of December 31, 2005 and December 31, 2004. We accrue the cost of post-retirement benefits during the years an employee provides service. The following tables summarize the status of our pension and other post-retirement benefit plans.

At December 31,	Pension Benefits 2005	Pension Benefits 2004	Post-retirement Benefits 2005	Post-retirement Benefits 2004
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 494,615	$469,651	$123,466	$125,324
Service cost	6,735	6,110	1,615	1,487
Interest cost	28,764	28,319	7,049	6,774
Plan participants' contributions	—	—	3,380	2,695
Benefits paid	(28,581)	(28,880)	(11,825)	(12,479)
Assumption changes	43,264	11,227	3,714	4,461
Recognition of Medicare Part D	—	—	—	(3,807)
Actuarial losses (gains)	430	8,050	279	(989)
Amendments	3,905	138	507	—
Benefit obligation, end of year	$ 549,132	$494,615	$128,185	$123,466
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 422,602	$409,932	$ 32,612	$ 22,543
Actual return on plan assets	26,604	39,870	1,276	1,802
Employer contribution	—	—	18,600	17,800
Plan participants' contributions	—	—	3,380	2,695
Benefits paid	(26,906)	(27,200)	(11,672)	(12,228)
Fair value of plan assets, end of year	$ 422,300	$422,602	$ 44,196	$ 32,612
Funded status	$(126,832)	$ (72,013)	$ (83,989)	$ (90,854)
Unrecognized net loss	118,821	70,807	33,757	30,424
Unrecognized transition obligation, net	—	—	27,839	31,768
Unrecognized prior service cost	17,051	15,906	(424)	(1,398)
Prepaid benefit (accrued) costs	$ 9,040	$ 14,700	$ (22,817)	$ (30,060)
Amounts Recognized in the Balance Sheets Consist Of:				
Prepaid benefit cost	$ 25,983	$ 30,597	$ N/A	$ N/A
Accrued benefit liability	(16,943)	(15,897)	(22,817)	(30,060)
Additional minimum liability	(80,758)	(41,815)	N/A	N/A
Intangible asset	17,051	15,906	N/A	N/A
Accumulated other comprehensive income	63,707	—	N/A	N/A
Regulatory asset	—	25,909	N/A	N/A
Net amount recognized	$ 9,040	$ 14,700	$ (22,817)	$ (30,060)

At December 31,	Pension Benefits 2005	Pension Benefits 2004	Post-retirement Benefits 2005	Post-retirement Benefits 2004
	(Dollars in Thousands)			
Accumulated Benefit Obligation	$494,018	$449,717	N/A	N/A
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$549,132	$494,615	N/A	N/A
Accumulated benefit obligation	494,018	449,717	N/A	N/A
Fair value of plan assets	422,300	422,602	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$549,132	$494,615	N/A	N/A
Accumulated benefit obligation	494,018	449,717	N/A	N/A
Fair value of plan assets	422,300	422,602	N/A	N/A
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	N/A	N/A	$128,185	$123,466
Fair value of plan assets	N/A	N/A	44,196	32,612
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.65%	5.90%	5.65%	5.90%
Compensation rate increase	3.50%	3.00%	3.50%	3.00%

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

We utilized the assistance of our plan actuaries in determining the discount rate assumption at December 31, 2005. Our actuaries have developed an interest rate yield curve to enable companies to make judgments pursuant to Emerging Issues Task Force (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.

The prior service cost (benefit) is amortized on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. The net actuarial loss (gain) 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 No. 87, “Employers’ Accounting for Pensions” and SFAS No. 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions.”

For the Year Ended December 31,	Pension Benefits 2005	Pension Benefits 2004	Pension Benefits 2003	Post-retirement Benefits 2005	Post-retirement Benefits 2004	Post-retirement Benefits 2003
	(Dollars in Thousands)					
Components of Net Periodic Cost (Benefit):						
Service cost	$ 6,735	$ 6,110	$ 5,381	$ 1,615	$ 1,487	$ 1,186
Interest cost	28,764	28,319	28,833	7,049	6,774	8,004
Expected return on plan assets	(36,272)	(38,561)	(40,513)	(2,552)	(1,999)	(1,431)
Amortization of unrecognized:						
Transition obligation, net	—	—	(177)	3,931	3,931	3,931
Prior service costs	2,761	2,762	3,358	(467)	(467)	(467)
Actuarial loss (gain), net	5,347	2,525	(2,032)	1,934	1,172	1,612
Curtailments, settlements and special term benefits	—	—	440	—	—	—
Net periodic cost (benefit)	$ 7,335	$ 1,155	$ (4,710)	$11,510	$10,898	$12,835
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):						
Discount rate	5.90%	6.10%	6.75%	5.90%	6.10%	6.75%
Expected long-term return on plan assets	8.75%	9.00%	9.00%	8.25%	8.50%	9.00%
Compensation rate increase	3.00%	3.10%	3.75%	3.00%	3.10%	3.75%

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.

In December 2003, the Medicare Prescription Drug Improvement and Modernization Act of 2003 (Medicare Act) became law. The Medicare Act introduced a prescription drug benefit under Medicare as well as a federal subsidy beginning in 2006. This subsidy 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 eligible for the federal subsidy. We adopted the guidance in the third quarter of 2004. 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 $5.2 million. The subsidy also decreased the net periodic post-retirement benefit cost by approximately $0.5 million for 2005.

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

	At December 31, 2005	At December 31, 2004
Health care cost trend rate assumed for next year	8.00%	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	2009	2008

The health care cost trend rate has a significant effect on 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	$ 139	$ (158)
Effect on post-retirement benefit obligation	1,235	(1,379)

The asset allocation for the pension plans and the post-retirement benefit plans at the end of 2005 and 2004, and the target allocations for 2006, by asset category, are as shown in the following table.

Asset Category	Target Allocations 2006	Plan Assets 2005	Plan Assets 2004
Pension Plans:			
Equity securities	65%	65%	68%
Debt securities	35%	29%	28%
Cash and other	0% - 5%	6%	4%
Total		100%	100%
Post-retirement Benefit Plans:			
Equity securities	65%	40%	35%
Debt securities	30%	50%	45%
Cash and other	5%	10%	20%
Total		100%	100%

We manage pension and retiree welfare plan assets in accordance with the “prudent investor” guidelines contained in the Employee Retirement Income Securities Act of 1974 (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. Investments are diversified 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. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

Expected Cash Flows	Pension Benefits To/(From) Trust	Pension Benefits To/(From) Company Assets	Post-Retirement Benefits To/(From) Trust	Post-Retirement Benefits To/(From) Company Assets
	(In Thousands)			
Expected contributions:				
2006 (a)	$ 21,000	$ 1,900	$ 12,900	$ 300
Expected benefit payments:				
2006	$ (26,500)	$ (1,900)	$ (8,600)	$ (300)
2007	(26,200)	(1,900)	(8,600)	(300)
2008	(26,000)	(1,800)	(8,600)	(300)
2009	(26,000)	(1,800)	(8,700)	(300)
2010	(26,200)	(1,800)	(8,700)	(300)
2011 – 2015	(144,400)	(8,600)	(44,500)	(1,500)

(a) The $21.0 million contribution to the pension trust is a voluntary contribution we expect to make in 2006.

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 $4.1 million for 2005, $3.4 million for 2004 and $3.0 million for 2003.

Under our former qualified employee stock purchase plan established in 1999, full-time, non-union employees purchased designated shares of our common stock at no more than a 15% discounted price. Our employees purchased 185,016 shares in 2004 at an average price of $17.20 per share. Employees purchased 403,705 shares in 2003 at an average price of $8.45 per share. We discontinued this plan effective January 1, 2005.

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. At December 31, 2005, awards of 3,647,098 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.

In December 2004, FASB issued SFAS No. 123R, “Share-Based Payment.” SFAS No. 123R requires companies to recognize as compensation expense the grant-date fair value of stock options and other equity-based compensation issued to employees. We implemented the provisions of the statement on January 1, 2006. We currently use RSUs for stock-based awards granted to employees. Given the characteristics of our stock-based compensation program, we do not expect the adoption of SFAS No. 123R to materially impact our consolidated results of operations.

In 2005, we granted 135,485 RSUs to officers and selected management employees. No RSUs were granted to members of our board of directors as this portion of the program was discontinued on January 1, 2005. In 2004, we granted 67,051 RSUs to selected management employees and directors. In 2003, we granted 559,095 RSUs to officers, selected management employees and directors. Each RSU represents a right to receive one share of our common stock at the end of the restricted period assuming certain criteria are met. The unearned compensation related to the grant of RSUs is shown as a separate component of shareholders’ equity. Unearned compensation is being amortized to expense over the vesting period.

Another component of the LTISA Plan is the Executive Stock for Compensation program, where in the past eligible employees were entitled to receive RSUs in lieu of current cash compensation. The Executive Stock for Compensation program was modified in 2001 to pay a portion of current compensation in the form of stock. Although this plan was discontinued in 2001, dividends will continue to be paid to plan participants on their outstanding plan balance until distribution. At the end of the deferral period, RSUs are paid in the form of stock. Plan participants were awarded 3,936 shares of common stock for dividends in 2005, 4,422 shares in 2004 and 10,009 shares in 2003. Participants received common stock distributions of 12,271 shares in 2005, 46,544 shares in 2004 and 5,101 shares in 2003.

Stock options under the LTISA plan are as follows.

	As of December 31,					
	2005		2004		2003	
	Shares (In Thousands)	Weighted-Average Exercise Price	Shares (In Thousands)	Weighted-Average Exercise Price	Shares (In Thousands)	Weighted-Average Exercise Price
Outstanding, beginning of year	225.2	$ 32.38	226.7	$ 32.92	232.6	$ 32.08
Exercised	(5.6)	23.20	(1.5)	15.31	—	—
Forfeited	—	—	—	—	(5.9)	24.99
Outstanding, end of year	219.6	32.61	225.2	32.38	226.7	32.92

Stock options issued and outstanding at December 31, 2005 are as follows.

	Range of Exercise Price	Number Issued and Outstanding	Weighted-Average Contractual Life in Years	Weighted-Average Exercise Price
Options - Exercisable:				
2000	$15.3125	5,250	5	$ 15.31
1999	27.8125-32.125	22,740	4	29.53
1998	38.625-43.125	55,890	3	41.15
1997	30.75	93,240	2	30.75
1996	29.25	42,470	1	29.25
Total outstanding		219,590		

RSUs under the LTISA plan are as follows.

	As of December 31,					
	2005		2004		2003	
	Shares (In Thousands)	Weighted-Average Grant Date Fair Value	Shares (In Thousands)	Weighted-Average Grant Date Fair Value	Shares (In Thousands)	Weighted-Average Grant Date Fair Value
Outstanding, beginning of year	1,298.4	$ 17.50	1,913.7	$ 16.25	1,619.9	$ 18.08
Granted	135.5	22.04	60.1	20.57	547.3	12.90
Vested	(336.0)	13.28	(668.4)	14.65	(251.8)	14.60
Forfeited	(3.4)	20.43	(7.0)	17.72	(1.7)	17.39
Outstanding, end of year	1,094.5	18.54	1,298.4	17.50	1,913.7	16.25

RSUs issued and outstanding at December 31, 2005 are as follows.

	Range of Fair Value at Grant Date	Number Issued and Outstanding
Restricted share units:		
2005	$21.64 –$22.56	134,337
2004	20.45	58,025
2003	10.39 - 17.75	245,896
2002	11.57	62,500
2001	17.67 – 19.61	196,640
2000	15.31 – 15.63	264,249
1999	27.61 – 32.13	63,783
1998	38.63	69,000
Total outstanding		1,094,430

We also issued dividend equivalents to recipients of stock options and RSUs. Recipients of RSUs receive dividend equivalents when dividends are paid on shares of company stock. The value of each dividend equivalent related to stock options is calculated by accumulating dividends that would have been paid or payable on a share of company common stock. The dividend equivalents, with respect to stock options, expire after nine years from date of grant. The weighted-average fair value at the grant-date of the dividend equivalents on stock options was $6.44 per share in 2005, $6.40 per share in 2004 and $6.38 per share in 2003.

13. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefits

The Wolf Creek pension plan expense and liabilities are measured using assumptions, which include discount rates, compensation rates and past and future estimated plan asset returns. Due to a decrease in interest rates and a corresponding decrease in the discount rates used to estimate pension liabilities, the fair value of the Wolf Creek pension plan assets was less than the accumulated benefit obligation at the measurement dates.

Table of Contents

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	
At December 31,	2005	2004	2005	2004
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 59,168	$ 49,927	$ 6,102	$ 5,455
Service cost	2,820	2,572	238	235
Interest cost	3,730	3,295	384	356
Plan participants' contributions	—	—	193	147
Benefits paid	(992)	(849)	(515)	(416)
Actuarial losses	6,811	4,223	603	325
Benefit obligation, end of year	$ 71,537	$ 59,168	$ 7,005	$ 6,102
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 32,491	$ 26,799	N/A	N/A
Actual return on plan assets	2,979	2,551	N/A	N/A
Employer contribution	5,084	3,810	N/A	N/A
Benefits paid	(802)	(669)	N/A	N/A
Fair value of plan assets, end of year	$ 39,752	$ 32,491	N/A	N/A
Funded status	$(31,785)	$(26,677)	$ (7,005)	$ (6,102)
Unrecognized net loss	20,850	15,239	2,645	2,211
Unrecognized transition obligation, net	342	398	403	461
Unrecognized prior service cost	188	220	—	—
Post-measurement date adjustments	205	740	—	—
Accrued post-retirement benefit costs	$(10,200)	$(10,080)	$ (3,957)	$ (3,430)
Amounts Recognized in the Balance Sheets Consist Of:				
Accrued benefit liability	$(10,200)	$(10,080)	$ (3,957)	$ (3,430)
Additional minimum liability	(5,144)	(3,144)	N/A	N/A
Intangible asset	530	618	N/A	N/A
Accumulated other comprehensive income	4,614	—	N/A	N/A
Regulatory asset	—	2,526	N/A	N/A
Net amount recognized	$(10,200)	$(10,080)	$ (3,957)	$ (3,430)

At December 31,	Pension Benefits 2005	Pension Benefits 2004	Post-retirement Benefits 2005	Post-retirement Benefits 2004
	(Dollars in Thousands)			
Accumulated Benefit Obligation	$55,302	$46,455	N/A	N/A
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$71,537	$59,168	N/A	N/A
Accumulated benefit obligation	55,302	46,455	N/A	N/A
Fair value of plan assets	39,752	32,491	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$71,537	$59,168	N/A	N/A
Accumulated benefit obligation	55,302	46,455	N/A	N/A
Fair value of plan assets	39,752	32,491	N/A	N/A
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	N/A	N/A	$ 7,005	$ 6,060
Fair value of plan assets	N/A	N/A	N/A	N/A
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.75%	6.00%	5.75%	6.00%
Compensation rate increase	3.25%	3.00%	N/A	N/A

Wolf Creek uses a measurement date of December 1 for the majority of its pension and post-retirement benefit plans.

Wolf Creek utilized the assistance of plan actuaries in determining the discount rate assumption at December 1, 2005. The actuaries have developed an interest rate yield curve to enable companies to make judgments pursuant to Emerging Issues Task Force (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.

For the Year Ended December 31,	Pension Benefits 2005	Pension Benefits 2004	Pension Benefits 2003	Post-retirement Benefits 2005	Post-retirement Benefits 2004	Post-retirement Benefits 2003
	(Dollars in Thousands)					
Components of Net Periodic Cost:						
Service cost	$ 2,820	$ 2,572	$ 2,545	$ 238	$ 235	$ 218
Interest cost	3,730	3,295	2,928	384	356	289
Expected return on plan assets	(3,114)	(2,780)	(2,464)	—	—	—
Amortization of unrecognized:						
Transition obligation, net	57	57	57	58	58	58
Prior service costs	31	31	31	—	—	—
Actuarial loss, net	1,340	802	603	170	141	99
Net periodic cost	$ 4,864	$ 3,977	$ 3,700	$ 850	$ 790	$ 664
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:						
Discount rate	6.00%	6.20%	6.75%	6.00%	6.10%	6.50%
Expected long-term return on plan assets	8.75%	9.00%	9.00%	N/A	N/A	N/A
Compensation rate increase	3.00%	3.20%	Graded rates	N/A	N/A	N/A

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.

	At December 31, 2005	At December 31, 2004
Health care cost trend rate assumed for next year	8.0%	8.5%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2012	2012

The health care cost trend rate has a significant effect on 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	$ 5	$ (5)
Effect on the present value of the accumulated projected benefit obligation	41	(41)

Table of Contents

The asset allocation for the pension plans at the end of 2005 and 2004, and the target allocation for 2006, by asset category are as shown in the following table.

Asset Category	Target Allocations 2006	Plan Assets 2005	Plan Assets 2004
Pension Plans:			
Equity securities	65%	63%	65%
Debt securities	35%	27%	28%
Other	0%	10%	7%
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 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. Investment risk is measured and monitored 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 Thousands)			
Expected contributions:				
2006	$ 6,000	$ 200	N/A	$ 300
Expected benefit payments:				
2006	$ (1,000)	$ (200)	N/A	$ (300)
2007	(1,200)	(200)	N/A	(300)
2008	(1,300)	(200)	N/A	(400)
2009	(1,600)	(200)	N/A	(400)
2010	(1,800)	(200)	N/A	(400)
2011 – 2015	(13,900)	(900)	N/A	(2,900)

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 $0.9 million for 2005, $0.8 million for 2004 and $0.9 million for 2003.

14. 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 “–Fuel Commitments,” that have an unexpended balance of approximately $166.2 million at December 31, 2005, of which $36.8 million has been committed. The $36.8 million commitment relates to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments at December 31, 2005 was as follows.

		Committed Amount (In Thousands)
2006	$	32,210
2007		4,530
2008		5
Thereafter		15
Total amount committed	$	36,760

Clean Air Act

We must comply with the Clean Air Act, state laws and implementing regulations that impose, among other things, limitations on major pollutants, including sulfur dioxide (SO2), 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 some emissions. We have installed continuous monitoring and reporting equipment in order to meet the acid rain requirements.

Environmental Projects

KCPL began updating or installing additional equipment related to emissions controls at La Cygne unit 1 for which we incurred costs beginning in 2005. We will continue to incur costs through the completion of installation in 2009. We anticipate that our share of these costs will be approximately $105.0 million. Additionally, we have identified the potential for up to $515.0 million of expenditures at other power plants for other environmental projects during the next 8 years. This cost could increase depending on the resolution of the Environmental Protection Agency (EPA) New Source Review described below. In addition to the capital investment, were we to install such equipment, we anticipate that we would incur significant annual expense to operate and maintain the equipment and the operation of the equipment would reduce net production from our plants. As discussed above, the ECRR will allow for the timely inclusion in rates capital expenditures that are directly tied to environmental improvements required by the Clean Air Act. However, increased operating and maintenance costs can only be recovered through a change in our base rates following a rate review.

The degree to which we will 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 regulations, new regulations, legislation, and the resolution of the EPA New Source Review described below. Although we expect to recover such costs through our utility rates, we can provide no assurance that we would be able to fully and timely recover all or any increased costs relating to environmental compliance. Failure to recover these associated costs could have a material adverse effect on our consolidated financial condition or results of operations.

EPA New Source Review

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 New Source Review requirements 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 have reasonably been expected to result in a significant net increase in emissions. The Clean Air Act requires companies to obtain permits and, if necessary, install control equipment to remove 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 the three coal-fired plants we operate. On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated pre-construction permitting requirements of the Clean Air Act.

We are in discussions with the EPA concerning this matter in an attempt to reach a settlement. We expect that any settlement with the EPA could require us to update or install emissions controls at Jeffrey Energy Center over an agreed upon number of years. 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. Together, these costs could be material. The EPA has informed us that it has referred this matter to the Department of Justice (DOJ) for the DOJ to consider whether to pursue an enforcement action in federal district court. We believe that costs related to updating or installing emissions controls would qualify for recovery through the ECRR. If we were to reach a settlement with the EPA, we may be assessed a penalty. The penalty could be material and may not be recovered in rates.

Manufactured Gas Sites

We have been associated with a number of former manufactured gas sites located in Kansas and Missouri. We and the Kansas Department of Health and Environment (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, our liability for twelve of the sites is limited. Of those twelve 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 and terminates in 2012. We have sole responsibility for remediation with respect to three sites.

Our liability for our former manufactured gas sites in Missouri is limited by an environmental indemnity agreement with Southern Union Company, which bought all of the Missouri manufactured gas sites. According to the terms of the agreement, our future liability for these sites is capped at $7.5 million and terminates in 2009.

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 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 KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the nuclear decommissioning study, the current-year funding and future funding. Phase two is the filing 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.

Wolf Creek filed an updated nuclear decommissioning site study with the KCC. Based on the 2005 site study of decommissioning costs, including the costs of decontamination, dismantling and site restoration, our share of such costs are estimated to be $243.3 million. This amount compares to the 2002 site study estimate for decommissioning costs of $220.0 million. The site study cost estimate represents the estimate to decommission Wolf Creek as of the site study year. The actual nuclear decommissioning costs may vary from the estimates because of changes in technology 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, as determined by the KCC for purposes of the funding schedule, will be 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 license expires in 2025. We believe that the KCC approved funding level will be sufficient to meet the NRC minimum financial assurance requirement. However, our consolidated results of operations would be materially adversely affected if we are not allowed to recover the full amount of the funding requirement.

Nuclear decommissioning costs that are recovered in rates are deposited in an external trust fund. In 2005, we expensed approximately $3.9 million for nuclear decommissioning. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $100.8 million at December 31, 2005 and $91.1 million at December 31, 2004.

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 $3.8 million in 2005, $4.3 million in 2004 and $3.8 million in 2003 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation produced. We include these disposal costs in operating 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. Currently, the DOE has not defined a schedule for submitting a license application. 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 the expiration of its operating license in 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. Both the nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry 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 $300.0 million exists for liability claims, regardless of the number of non-certified acts affecting Wolf Creek or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of $3.24 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. For certified acts of terrorism, the individual policy limits apply. 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 $10.8 billion. This limit of liability consists of the maximum available commercial insurance of $300.0 million, and the remaining $10.5 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, we can be assessed up to $100.6 million per incident at any commercial reactor in the country, payable at no more than $15.0 million per incident per year. This 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. 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 $26.5 million (our share is $12.4 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 condition and results of operations.

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. At December 31, 2005, our share of Wolf Creek's nuclear fuel commitments were approximately $12.4 million for uranium concentrates expiring in 2007, $2.0 million for conversion expiring in 2007, $9.7 million for enrichment expiring at various times through 2006 and $54.1 million for fabrication through 2024. In addition, letters of intent have been issued with suppliers for major portions of Wolf Creek's future uranium, conversion and enrichment requirements extending through 2017.

At December 31, 2005, our coal and coal transportation contract commitments in 2005 dollars under the remaining terms of the contracts were approximately $1.5 billion. The largest contract expires in 2020, with the remaining contracts expiring at various times through 2013.

At December 31, 2005, our natural gas transportation commitments in 2005 dollars under the remaining terms of the contracts were approximately $38.7 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2010, except for one contract that expires in 2016.

Energy Act

As part of the 1992 Energy Policy Act, a special assessment is being collected from utilities for a Uranium Enrichment Decontamination and Decommissioning Fund. Our portion of the assessment, including carrying costs, for Wolf Creek is approximately $9.7 million, adjusted for inflation. To date, we have paid approximately $9.0 million, with the estimated remainder payable over the next year. We recover such costs from prices we charge our customers.

15. ASSET RETIREMENT OBLIGATIONS

In accordance with SFAS No. 143, adopted January 2003, and FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations” (FIN 47), adopted December 31, 2005, 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.

Legal Liability

On January 1, 2003, we recognized the liability for our 47% share of the estimated cost to decommission Wolf Creek. SFAS No. 143 requires the recognition of the fair value of the asset retirement obligation we incurred at the time Wolf Creek was placed into service in 1985. On January 1, 2003, we recorded an asset retirement obligation of $74.7 million. In addition, we increased our property and equipment balance, net of accumulated depreciation, by $10.7 million.

During 2005 we updated our nuclear decommissioning and dismantlement study. Based upon the results of the 2005 study, we have revised our estimate of our Wolf Creek asset retirement obligation. Accordingly, in 2005 we increased our asset retirement liability $14.6 million. Costs to retire Wolf Creek are currently being recovered through rates as provided by the KCC.

In addition, during 2005 we determined that we have conditional asset retirement obligations that are within the scope of FIN 47. The conditional asset retirement obligations include disposal of asbestos insulating material at our power plants, remediation of ash disposal ponds and the disposal of polychlorinated biphenyl (PCB) contaminated oil. As of December 31, 2005, we recorded an asset retirement obligation of approximately $21.2 million pursuant to the requirements of FIN 47 based on the fair value of these disposal obligations.

The amount of the retirement obligation related to asbestos disposal was recorded as of 1990, the date when the Environmental Protection Agency published the "National Emission Standards for Hazardous Air Pollutants: Asbestos NESHAP Revision; Final Rule." We also capitalized the retirement obligation as an increase to the asset's carrying value.

We operate, as permitted by the state of Kansas, ash landfills at several of our power plants. We have determined that the closure of these facilities represents a conditional asset retirement obligation as defined by FIN 47. Accordingly we have recognized an asset retirement obligation for the ash landfills. The liability was determined based upon the date each landfill was originally placed in service.

PCB contaminates are contained within company electrical equipment, primarily transformers. We have determined that the disposal of PCB-contaminated equipment represents a conditional asset retirement obligation as defined by FIN 47. Accordingly, we have recognized an asset retirement obligation for the PCB-contaminated equipment. The liability was determined based upon the PCB regulations that originally became effective in 1978.

The following table summarizes our legal asset retirement obligations included on our consolidated balance sheets in long-term liabilities.

	As of December 31,		
	2005	2004	2003
	(In Thousands)		
Beginning asset retirement obligation	$ 87,118	$80,695	$ —
Transition liability	6,336	—	74,745
Accretion expense	21,796	6,423	5,950
Additional estimated liability	14,638	—	—
Ending asset retirement obligation	$129,888	$87,118	$80,695

Cumulative Effect of FIN 47: In March 2005, the FASB issued FIN 47. The interpretation clarified the term "conditional asset retirement obligation" as used in SFAS No. 143. The recording of the obligation 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. If we had implemented FIN 47 at January 1, 2004, the liability for asset retirement obligations would have been $19.1 million. The liability at December 31, 2004 would have been $20.1 million. The following table summarizes the accounting for the initial adoption of FIN 47, as of December 31, 2005.

	Plant Assets	Regulatory Assets	Long-Term Liabilities
		(In Thousands)	
Reflect retirement obligation when liability incurred	$ 6,336	$ —	$ 6,336
Record accretion of liability to adoption date	—	14,861	14,861
Record depreciation of plant to adoption date	(3,825)	3,825	—
Net impact of FIN 47	$ 2,511	$ 18,686	$ 21,197

Non-Legal Liability – Cost of Removal

We recover in rates, as a component of depreciation, the costs to dispose of utility plant assets that do not represent legal retirement obligations. At December 31, 2005 and 2004, Westar Energy had incurred, but had not recovered, $0.3 million and $1.3 million, respectively, in removal costs, which were classified as a regulatory asset. At December 31, 2005 and 2004, KGE had $6.9 million and $2.6 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.

16. LEGAL PROCEEDINGS

We and certain of our present and former officers and directors are defendants in a consolidated purported class action lawsuit in United States District Court in Topeka, Kansas, “In Re Westar Energy, Inc. Securities Litigation,” Master File No. 5:03-CV-4003 and related cases. In early April 2005, we reached an agreement in principle with the plaintiffs to settle this lawsuit for $30.0 million. The full terms of the proposed settlement are set forth in a Stipulation and Agreement of Compromise, Settlement and Release dated as of May 31, 2005 filed with the court. On September 1, 2005, the court approved the proposed settlement and directed the parties to consummate the settlement in accordance with the stipulation. Pursuant to the stipulation, we paid $1.25 million and our insurance carriers paid $28.75 million into a settlement fund that upon effectiveness of the settlement will be disbursed, after payment of $9.0 million of legal fees for plaintiffs’ counsel plus expenses, to shareholders as provided in the stipulation. The amounts paid by our insurance carriers in this settlement include the payments related to the settlement of the shareholder derivative lawsuit described below. The effectiveness of the settlement is conditioned upon the entry of a final judgment approving the settlement of the shareholder derivative lawsuit described in the following paragraph. No final judgment has been entered in the shareholder derivative lawsuit, the status of which is described in the following paragraph.

Certain present and former members of our board of directors and officers are defendants in a shareholder derivative complaint filed April 18, 2003, “Mark Epstein vs David C. Wittig, Douglas T. Lake, Charles Q. Chandler IV, Frank J. Becker, Gene A. Budig, John C. Nettels, Jr., Roy A. Edwards, John C. Dicus, Carl M. Koupal, Jr., Larry D. Irick and Cleco Corporation, defendants, and Westar Energy, Inc., nominal defendant, Case No. 03-4081-JAR.” In early April 2005, a special litigation committee of our board of directors approved an agreement in principle to settle this lawsuit for $12.5 million to be paid to us by our insurance carriers. The full terms of the proposed settlement are set forth in a Stipulation and Agreement of Compromise, Settlement and Release dated May 31, 2005 filed with the court. On September 1, 2005, the court approved the proposed settlement and directed the parties to consummate the settlement in accordance with the stipulation. Pursuant to the stipulation, the recovery from our insurance carriers, less attorney’s fees of $2.5 million, was paid into the settlement fund for the settlement of the securities class action lawsuit as described above. On September 16, 2005, one shareholder filed a motion asking the court to reconsider its order approving the settlement. The court denied this motion on December 2, 2005, and the shareholder then filed a timely appeal with the United States Court of Appeals for the Tenth Circuit. The appeal is now being briefed by the parties.

We and certain of our present and former officers and employees are defendants in a consolidated purported class action lawsuit filed in United States District Court in Topeka, Kansas, “In Re Westar Energy ERISA Litigation, Master File No. 03-4032-JAR.” The lawsuit is brought on behalf of participants in, and beneficiaries of, our Employees’ 401(k) Savings Plan between July 1, 1998 and January 1, 2003. On January 31, 2006, we reached an agreement in principle with the plaintiffs to settle this lawsuit for $9.25 million, which will be paid by our insurance carrier. The full terms of the proposed settlement will be set forth in a Class Action Settlement Agreement expected to be filed with the court by March 17, 2006. The settlement is subject to approval by the court. The court will conduct a hearing, which has not yet been scheduled, to consider whether the settlement is fair, reasonable and adequate.

In connection with the settlement of these lawsuits, we have recorded $40.50 million in other current assets related to the establishment of the settlement funds and an offsetting liability of $41.75 million. We also recognized expenses of $1.25 million related to the administration of the settlement of the class action lawsuit and derivative complaint.

On June 13, 2003, we filed a demand for arbitration with the American Arbitration Association asserting claims against David C. Wittig, our former president, chief executive officer and chairman, and Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, arising out of their previous employment with us. Mr. Wittig and Mr. Lake have filed counterclaims against us in the arbitration alleging substantial damages related to the termination of their employment and the publication of the report of the special committee of our board of directors. We intend to vigorously defend against these claims. The arbitration has been stayed pending final judgment in the trial of Mr. Wittig and Mr. Lake on criminal charges in U.S. District Court in the District of Kansas. On September 12, 2005, the jury convicted Mr. Wittig and Mr. Lake on the charges relevant to each of them. Sentencing is currently scheduled for April 3, 2006. We are unable to predict the ultimate impact of this matter on our consolidated results of operations.

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 results of operations.

See also Notes 3, 14, 17 and 18 for discussion of KCC regulatory proceedings, alleged violations of the Clean Air Act, an investigation by the United States Attorney’s Office, an inquiry by the Securities and Exchange Commission (SEC), an investigation by FERC and potential liabilities to Mr. Wittig and Mr. Lake.

17. ONGOING INVESTIGATIONS

Grand Jury Subpoena

On September 17, 2002, we were served with a federal grand jury subpoena by the United States Attorney’s Office in Topeka, Kansas, requesting information concerning the use of aircraft and our annual shareholder meetings. Since that date, the United States Attorney’s Office has served additional subpoenas on us and certain of our employees requesting further information concerning the use of our aircraft; executive compensation arrangements with Mr. Wittig, Mr. Lake and other former and present officers; the proposed rights offering of Westar Industries stock that was abandoned; and the company in general. We are providing information in response to these requests and we are cooperating fully in the investigation. We have not been informed that we are a target of the investigation. On December 4, 2003, Mr. Wittig and Mr. Lake were indicted by the federal grand jury on conspiracy, fraud and other criminal charges related to their actions while serving as our officers. For additional information regarding the jury trial of Mr. Wittig and Mr. Lake, see Note 18, “Potential Liabilities to David C. Wittig and Douglas T. Lake.”

Securities and Exchange Commission Inquiry

On November 1, 2002, the SEC notified us that it would be conducting an inquiry into the matters involved in the restatement of our first and second quarter 2002 financial statements. Our counsel has communicated with the SEC about these and other matters within the scope of the grand jury investigation, including disclosures in our proxy statements concerning personal aircraft use by former officers and the payment of a bonus to Mr. Wittig in 2002. We are unable to predict the ultimate outcome of the inquiry or its impact on us.

FERC Subpoena

On May 19, 2005, we and FERC reached a settlement regarding the matters related to the FERC investigation of power trades with Cleco Corporation and its affiliates, power transactions between our system and our marketing operations and power trades in which we or other trading companies acted as intermediaries. The settlement does not require us to make any monetary payments. As part of the settlement, we will follow a three-year plan to ensure compliance with FERC rules. The settlement was neither a finding of wrongdoing by FERC nor an admission of wrongdoing by us.

Department of Labor Investigation

On February 1, 2005, we received a subpoena from the Department of Labor seeking documents related to our Employees' 401(k) Savings Plan and our defined pension benefit plan. We have provided information to the Department of Labor pursuant to the subpoena and subsequent inquiries. At this time, we do not know the specific purpose of the investigation and we are unable to predict the ultimate outcome of the investigation or its impact on us. See Note 16, "Legal Proceedings," for discussion of a class action lawsuit brought on behalf of participants in our Employees' 401(k) Savings Plan.

18. POTENTIAL LIABILITIES TO DAVID C. WITTIG AND DOUGLAS T. LAKE

David C. Wittig, our former chairman of the board, president and chief executive officer, resigned from all of his positions with us and our affiliates on November 22, 2002. On May 7, 2003, our board of directors determined that the employment of Mr. Wittig was terminated as of November 22, 2002 for cause. Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, was placed on administrative leave from all of his positions with us and our affiliates on December 6, 2002. On June 12, 2003, our board of directors terminated the employment of Mr. Lake for cause.

On June 13, 2003, we filed a demand for arbitration with the American Arbitration Association asserting claims against Mr. Wittig and Mr. Lake arising out of their previous employment with us. Among other things, we are seeking to recover compensation and benefits previously paid to Mr. Wittig and Mr. Lake and to avoid compensation and other benefits Mr. Wittig and Mr. Lake claim to be owed to them as a result of their previous employment with us. We are unable to predict the outcome of the arbitration.

At December 31, 2005, we had accrued liabilities totaling approximately $60.1 million for compensation not yet paid to Mr. Wittig and Mr. Lake under various plans. The compensation includes RSU awards, deferred vested shares, deferred RSU awards, deferred vested stock for compensation, executive salary continuation plan benefits and, in the case of Mr. Wittig, benefits arising from a split dollar life insurance agreement. The amount of our obligation to Mr. Wittig related to a split dollar life insurance agreement is subject to adjustment at the end of each quarter based on the total return to our shareholders from the date of that agreement. The total return considers the change in stock price and accumulated dividends. These compensation-related accruals are included in long-term liabilities on the consolidated balance sheets with a portion recorded as a component of paid in capital. The amount accrued will increase annually as it relates to future dividends on deferred RSU awards and increases in amounts that may be due under the executive salary continuation plan.

In addition, we have accrued $6.3 million as of December 31, 2005 for legal fees and expenses incurred by Mr. Wittig and Mr. Lake that are recorded in accounts payable on our consolidated balance sheets. These legal fees and expenses were incurred in the defense of the criminal charges filed by the United States Attorney's Office in Topeka, Kansas. On September 12, 2005, the jury convicted Mr. Wittig and Mr. Lake on the charges relevant to each of them. We will likely incur substantial additional expenses for legal fees and expenses incurred by Mr. Wittig and Mr. Lake related to the possible appeal of these convictions and the arbitration proceeding discussed above. We have filed lawsuits against Mr. Wittig and Mr. Lake claiming that the legal fees and expenses they have incurred, which we have advanced or for which they seek advancement in the defense of the criminal charges, are unreasonable and excessive. We have asked the court to determine the amount of the legal fees and expenses that were reasonably incurred and which we have an obligation to advance. We are unable to estimate the amount of the legal fees and expenses incurred or that will be incurred by Mr. Wittig and Mr. Lake for which we may be ultimately responsible. We are also currently unable to determine the amount of the fees which may be recovered under any applicable directors and officers liability insurance policies.

In addition to these amounts, we could also be obligated to make payments to Mr. Wittig and Mr. Lake pursuant to the executive salary continuation plan. Assuming an expected payout period of 35 years, the aggregate nominal amount of these payments would be approximately $15.9 million for Mr. Wittig and $8.0 million for Mr. Lake.

The jury in the trial of Mr. Wittig and Mr. Lake also determined that Mr. Wittig and Mr. Lake should forfeit to the United States certain property that it determined was derived from their criminal conduct. The court subsequently entered preliminary orders of forfeiture with respect to the property forfeited by Mr. Wittig and Mr. Lake. The forfeited property consists substantially of compensation and benefits that we are seeking to avoid payment of in the arbitration proceeding referenced above. We believe that we have exclusive or superior rights in the forfeited property. We have filed petitions with the court asserting these rights with respect to the property forfeited by Mr. Wittig and Mr. Lake. We are unable to predict whether the court will decide that the rights we have asserted are exclusive or superior to the rights of the United States or other persons who may assert rights in the forfeited property.

19. REDEMPTION OF GUARDIAN INTERNATIONAL PREFERRED STOCK

On July 9, 2004, Guardian International, Inc. (Guardian) redeemed 8,397 shares of Guardian Series C preferred stock held of record by us. The redemption price was $8.6 million, representing the par value of $1,000 per share, or $8.4 million, plus $0.2 million in accrued dividends through the date of redemption and the redemption premium. In 2002, we granted certain current and former officers 540 RSUs linked to these securities. In 2002, we also transferred beneficial ownership of 4,714 shares of Guardian Series C preferred stock to Mr. Wittig and Mr. Lake in exchange for other securities. The ownership of these shares and related dividends is disputed and is the subject of the arbitration proceeding with Mr. Wittig and Mr. Lake discussed above in Note 16, “Legal Proceedings.” We recorded an approximate $0.6 million increase in the balance of our potential liability to Mr. Wittig and Mr. Lake in the third quarter of 2004 to reflect the difference between the carrying value of the 4,714 shares claimed by Mr. Wittig and Mr. Lake and the redemption amount.

20. COMMON AND PREFERRED STOCK

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. At December 31, 2005, we had 86,835,371 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 2005, a total of 805,650 shares were issued by Westar Energy for the DSPP, the Employee Stock Purchase Plan and other stock based plans operated under the 1996 Long-Term Incentive and Share Award Plan. At December 31, 2005, a total of 5,056,725 shares were available under the DSPP registration statement.

Common Stock Issuance

Westar Energy sold approximately 12.5 million shares of its common stock in 2004 for net proceeds of $245.1 million.

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 at December 31, 2005.

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 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, shall not exceed 75% of its net income available for dividends for such 12-month period. 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. At December 31, 2005, 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 Subordinated 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.

21. 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 24 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:		
2003	$ 28,895	$ 42,495
2004	28,895	38,793
2005	23,481	34,239
Future commitments:		
2006	$ 33,535	$ 44,637
2007	23,464	32,703
2008	32,892	41,352
2009	32,964	39,855
2010	33,041	39,447
Thereafter	355,805	381,992
Total future commitments	$511,701	$579,986

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

On June 30, 2005, KGE and the owner of La Cygne unit 2 amended certain terms of the agreement relating to KGE's lease of La Cygne unit 2, including an extension of the lease term. The lease was entered into in 1987 with an initial term ending in September 2016. With the June 30, 2005 extension, the term of the lease will expire in September 2029. Upon expiration of the lease term in 2029, 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.

On June 30, 2005, KGE caused the owner of La Cygne unit 2 to refinance the debt used by the owner to finance the purchase of the facility. The savings resulting from extending the term of the lease and refinancing the debt will reduce KGE's annual lease expense by approximately $10.8 million.

Capital Leases

Capital leases are identified based on the requirements set forth in SFAS No. 13, "Accounting for Leases." For both vehicles and computer equipment, new leases are signed each month based on the terms of the master lease agreement. The lease term for vehicles is from 5 to 14 years depending on the type of vehicle. The computer equipment has either a 2- or 3-year term. Assets recorded under capital leases are listed below.

	December 31, 2005	December 31, 2004
	(In Thousands)	
Vehicles	$ 33,518	$ 35,769
Computer equipment and software	4,168	2,145
Accumulated amortization	(19,375)	(17,848)
Total capital leases	$ 18,311	$ 20,066

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 at December 31, 2005 are listed below.

Year Ended December 31,	Total Capital Leases (In Thousands)
2006	$ 5,845
2007	4,982
2008	3,847
2009	2,951
2010	2,120
Thereafter	3,633
	23,378
Amounts representing imputed interest	(5,067)
Present value of net minimum lease payments under capital leases	$ 18,311

22. RELATED PARTY TRANSACTIONS — ONEOK Shared Services Agreement

We and ONEOK had shared services agreements in which we provided and billed one another for facilities, utility field work, mobile communications, information technology, customer support, meter reading and bill processing. Payments for these services were based on various hourly charges, negotiated fees and out-of-pocket expenses.

	Year Ended December 31,	
	2004	2003
Charges to ONEOK	$ 7,213	$ 8,312
Charges from ONEOK	$ 2,735	$ 3,190

ONEOK terminated portions of this shared services agreement in September 2004, including electric service orders, call center functions, bill processing and remittance processing. In addition to joint meter reading, we continue to share some facilities and a mobile communications system.

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

In 2005, we recorded approximately $0.7 million in income in our results of discontinued operations due to the resolution of indemnification issues with the sale of the Protection One Europe security business.

In 2003, we classified our monitored security businesses as discontinued operations. We also reclassified historical periods to conform with this classification.

We sold our interest in Protection One Europe on June 30, 2003. The sale resulted in a $58.7 million reduction in our consolidated debt level from the buyer’s assumption of $48.2 million of Protection One Europe debt that was included on our consolidated financial statements and the use of $10.5 million of cash proceeds to pay down debt.

On February 17, 2004, we closed the sale of our interest in Protection One to subsidiaries of Quadrangle Capital Partners LP and Quadrangle Master Funding Ltd. (together, Quadrangle). At closing, we assigned to Quadrangle the senior credit facility between Westar Industries, Inc., Westar Energy’s wholly owned subsidiary, and Protection One, which had an outstanding balance of $215.5 million. At closing, we received proceeds of $122.2 million.

Protection One had been part of our consolidated tax group since 1997. Under the terms of a tax sharing agreement, we have reimbursed Protection One for current tax benefits used in our consolidated tax return attributable to Protection One. On November 12, 2004, we entered into a settlement agreement with Protection One and Quadrangle that, among other things, terminated a tax sharing agreement, settled Protection One's claims with us relating to the tax sharing agreement and settled claims between Quadrangle and us relating to the sale transaction. Pursuant to the terms of the settlement agreement, Quadrangle paid us $32.5 million in cash as additional consideration, and we settled tax sharing-related obligations to Protection One by tendering $27.1 million in Protection One 7-3/8% senior notes, including accrued interest, and paying $45.9 million in cash. Our net cash payment under the settlement agreement was $13.4 million. In addition, the settlement agreement provided that we would jointly agree to make an Internal Revenue Code (IRC) Section 338(h)(10) election. For tax purposes, an IRC Section 338(h)(10) election allows us to treat the sale of Protection One stock as a sale of the assets of Protection One.

Results of discontinued operations are presented in the table below.

	Year Ended December 31,		
	2005 (a)	2004 (b)	2003
	(In Thousands, Except Per Share Amounts)		
Sales	$ —	$ 22,466	$ 306,938
Costs and expenses	—	19,937	289,900
Earnings from discontinued operations before income taxes	—	2,529	17,038
Estimated gain (loss) on disposal	1,232	30,980	(258,979)
Income tax expense (benefit)	490	(45,281)	(164,036)
Results of discontinued operations	$ 742	$ 78,790	$ (77,905)
Basic results of discontinued operations per share	$ 0.01	$ 0.95	$ (1.08)
Diluted results of discontinued operations per share	$ 0.01	$ 0.94	$ (1.06)

(a) Amounts are related to the resolution of indemnification issues associated with the sale of Protection One Europe.
(b) Includes results through February 17, 2004 when Protection One was sold.

24. 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.

A significant factor affecting our 2005 quarterly results was the recognition of the change in the market value of our fuel contracts. Based on the terms of certain fuel supply contracts, changes in the fair value of these contracts were marked-to-market through earnings in accordance with the requirements of SFAS No. 133. We recognized non-cash gains of $12.3 million for the three months ended March 31, 2005, $13.0 million for the three months ended June 30, 2005 and $45.8 million for the three months ended September 30, 2005. As a result of the December 28, 2005 KCC Order implementing the RECA, we reversed $70.9 million of these previously recognized mark-to-market adjustments to fuel expense during the fourth quarter of 2005. During the three months ended March 31, 2004, no mark-to-market adjustments were recognized. We recognized a non-cash loss of $0.4 million for the three months ended June 30, 2004, a non-cash gain of $3.8 million in the three months ended September 30, 2004 and a non-cash loss of $3.9 million in the three months ended December 31, 2004.

Also as a result of the December 28, 2005 KCC Order, during the fourth quarter of 2005 we recorded a $10.4 million write-off of disallowed plant costs and established a regulatory asset for depreciation differences, which allowed us to record a reduction in depreciation expense of $20.1 million.

In addition, our net results of discontinued operations varied between comparable quarters. In the fourth quarter of 2005, we recognized income from discontinued operations of $0.7 million, which reflects the resolution of indemnification issues with the sale of the Protection One Europe security business. In the fourth quarter of 2004, we recognized income from discontinued operations of $71.9 million, which reflects the results of the final settlement of issues related to the sale of our monitored security business.

2005	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Sales	$336,502	$374,802	$477,896	$394,078
Income from continuing operations	15,615	27,876	84,475	6,901
Results of discontinued operations, net of tax	—	—	—	742
Net income	15,615	27,876	84,475	7,643
Earnings available for common stock	$ 15,373	$ 27,634	$ 84,233	$ 7,401
Per Share Data (a):				
Basic:				
Earnings available from continuing operations	$ 0.18	$ 0.32	$ 0.97	$ 0.07
Discontinued operations, net of tax	—	—	—	0.01
Earnings available	$ 0.18	$ 0.32	$ 0.97	$ 0.08
Diluted:				
Earnings available from continuing operations	$ 0.18	$ 0.32	$ 0.96	$ 0.07
Discontinued operations, net of tax	—	—	—	0.01
Earnings available	$ 0.18	$ 0.32	$ 0.96	$ 0.08
Cash dividend declared per common share	$ 0.23	$ 0.23	$ 0.23	$ 0.23
Market price per common share:				
High	$ 23.80	$ 24.29	$ 24.97	$ 24.80
Low	$ 21.07	$ 21.10	$ 22.90	$ 21.26

(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.

2004	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Sales	$340,263	$358,430	$421,489	$344,307
Income from continuing operations	8,791	13,979	60,369	16,941
Results of discontinued operations, net of tax	6,888	—	—	71,902
Net income	15,679	13,979	60,369	88,843
Earnings available for common stock	$ 15,437	$ 13,737	$ 60,127	$ 88,599
Per Share Data (a):				
Basic:				
Earnings available from continuing operations	$ 0.12	$ 0.16	$ 0.70	$ 0.19
Discontinued operations, net of tax	0.09	—	—	0.84
Earnings available	$ 0.21	$ 0.16	$ 0.70	$ 1.03
Diluted:				
Earnings available from continuing operations	$ 0.12	$ 0.16	$ 0.69	$ 0.19
Discontinued operations, net of tax	0.09	—	—	0.83
Earnings available	$ 0.21	$ 0.16	$ 0.69	$ 1.02
Cash dividend declared per common share	$ 0.19	$ 0.19	$ 0.19	$ 0.23
Market price per common share:				
High	$ 21.00	$ 21.47	$ 21.11	$ 22.92
Low	$ 18.06	$ 18.24	$ 19.58	$ 20.05

(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, at December 31, 2005, our disclosure controls and procedures are effective 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 recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

There were no changes in our internal control over financial reporting during the fourth quarter ended December 31, 2005, 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 2006 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (the 2006 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 2006 Proxy Statement, and that information is incorporated by reference in this Form 10-K. The information required by Item 406 of Regulation S-K will be included under the caption "Corporate Governance Matters" in our 2006 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 2006 Proxy Statement under the captions "Compensation of Directors," "Compensation of Executive Officers" and "Employment Contracts," and that information is incorporated by reference in this Form 10-K.

Table of Contents

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 will be set forth in our 2006 Proxy Statement under the captions “Beneficial Ownership of Voting Securities” and “Equity Compensation Plan Information,” and that information is incorporated by reference in this Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not applicable.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by Item 14 will be set forth in our 2006 Proxy Statement under the captions “Principal 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, 2005 and 2004

Consolidated Statements of Income for the years ended December 31, 2005, 2004 and 2003

Consolidated Statements of Comprehensive Income for the years ended December 31, 2005, 2004 and 2003

Consolidated Statements of Cash Flows for the years ended December 31, 2005, 2004 and 2003

Consolidated Statements of Shareholders’ Equity for the years ended December 31, 2005, 2004 and 2003

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

Table of Contents

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
3(a)	-By-laws of Westar Energy, Inc., as amended April 28, 2004 (filed as Exhibit 3(a) to the Form 10-Q for the period ended June 30, 2004 filed on August 4, 2004)	I
3(b)	-Restated Articles of Incorporation of Westar Energy, Inc., as amended through May 25, 1988 (filed as Exhibit 4 to the Form S-8 Registration Statement, SEC File No. 33-23022 filed on July 15, 1988)	I
3(c)	-Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-K405 for the period ended December 31, 1998 filed on April 14, 1999)	I
3(d)	-Certificate of Designations for Preference Stock, 8.5% Series (filed as Exhibit 3(d) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
3(e)	-Certificate of Correction to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(b) to the Form 10-K for the period ended December 31, 1991 filed on March 30, 1992)	I
3(f)	-Certificate of Designations for Preference Stock, 7.58% Series (filed as Exhibit 3(e) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
3(g)	-Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(c) to the Form 10-K for the period ended December 31, 1994 filed on March 30, 1995)	I
3(h)	-Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-Q for the period ended June 30, 1994 filed on August 11, 1994)	I
3(i)	-Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(a) to the Form 10-Q for the period ended June 30, 1996 filed on August 14, 1996)	I
3(j)	-Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-Q for the period ended March 31, 1998 filed on May 12, 1998)	I
3(k)	-Form of Certificate of Designations for 7.5% Convertible Preference Stock (filed as Exhibit 99.4 to the Form 8-K filed on November 17, 2000)	I
3(l)	-Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(l) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003)	I
3(m)	-Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(m) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003)	I
3(n)	-Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(m) to the Form S-3 Registration Statement No. 333-125828 filed on June 15, 2005)	I
4(a)	-Mortgage and Deed of Trust dated July 1, 1939 between Westar Energy, Inc. and Harris Trust and 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
	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
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
12	-Computations of Ratio of Consolidated Earnings to Fixed Charges	#
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

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, 2003				
Allowances deducted from assets for doubtful accounts	$ 6,618	$ 3,874	$ (5,077)	$ 5,415
Year ended December 31, 2004				
Allowances deducted from assets for doubtful accounts	$ 5,415	$ 2,718	$ (2,820)	$ 5,313
Year ended December 31, 2005				
Allowances deducted from assets for doubtful accounts	$ 5,313	$ 3,959	$ (4,039)	$ 5,233

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

SIGNATURE

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

WESTAR ENERGY, INC.

Date: March 13, 2006

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/ JAMES S. HAINES, JR. (James S. Haines, Jr.)	Director, Chief Executive Officer and President (Principal Executive Officer)	March 13, 2006
/s/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 13, 2006
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	March 13, 2006
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	March 13, 2006
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	March 13, 2006
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	March 13, 2006
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	March 13, 2006
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	March 13, 2006
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	March 13, 2006
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	March 13, 2006
/s/ JOHN C. NETTELS, JR. (John C. Nettels, Jr.)	Director	March 13, 2006

Exhibit 12

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,				
	2005	2004	2003	2002	2001
Earnings from continuing operations (a)	$195,485	$133,542	$244,542	$ 68,245	$ 34,710
Fixed Charges:					
Interest expense	111,735	143,953	225,901	237,418	224,777
Interest on corporate-owned life insurance borrowings	51,058	50,429	52,839	52,768	50,409
Interest applicable to rentals	23,324	21,377	23,084	24,647	30,377
Total Fixed Charges	186,117	215,759	301,824	314,833	305,563
Distributed income of equity investees	—	—	—	2,916	2,769
Preferred Dividend Requirements:					
Preferred dividends (b)	970	970	968	399	895
Income tax required	435	324	485	(52)	(403)
Total Preferred Dividend Requirements	1,405	1,294	1,453	347	492
Total Fixed Charges and Preferred Dividend Requirements	187,522	217,053	303,277	315,180	306,055
Earnings (c)	$381,602	$349,301	$546,366	$385,994	$343,042
Ratio of Earnings to Fixed Charges	2.05	1.62	1.81	1.23	1.12
Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements	2.03	1.61	1.80	1.22	1.12

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

(c) Earnings are deemed to consist of earnings from continuing operations, fixed charges and distributed income of equity investees. Fixed charges consist of all interest on indebtedness, amortization of debt discount and expense, and the portion of rental expense that represents an interest factor.

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
2) WR Receivables Corporation	Kansas	June 22, 2000

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

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-125828, 333-113415 and 333-118809 on Form S-3; Nos. 333-93355, 333-70891, 333-13229, and 333-75395 on Form S-8; of our reports on the consolidated financial statements dated March 10, 2006 (which reports express an unqualified opinion and include an explanatory paragraph regarding revisions made to the consolidated statements of cash flows for the years ended December 31, 2004 and 2003), relating to the financial statements and financial statement schedule of Westar Energy, Inc., and management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10-K of Westar Energy, Inc. for the year ended December 31, 2005.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
March 10, 2006

Exhibit 31(a)

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

I, James S. Haines, Jr., certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2005 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: March 13, 2006

By: /s/ James S. Haines, Jr.

James S. Haines, Jr.,
Director, Chief Executive Officer and President
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, 2005 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: March 13, 2006

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, 2005 (the Report), which this certification accompanies, James S. Haines, Jr., 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: March 13, 2006	By: /s/ James S. Haines, Jr. James S. Haines, Jr., Director, Chief Executive Officer and President
Date: March 13, 2006	By: /s/ Mark A. Ruelle Mark A. Ruelle, Executive Vice President and Chief Financial Officer