Westar Energy

2006 ANNUAL REPORT

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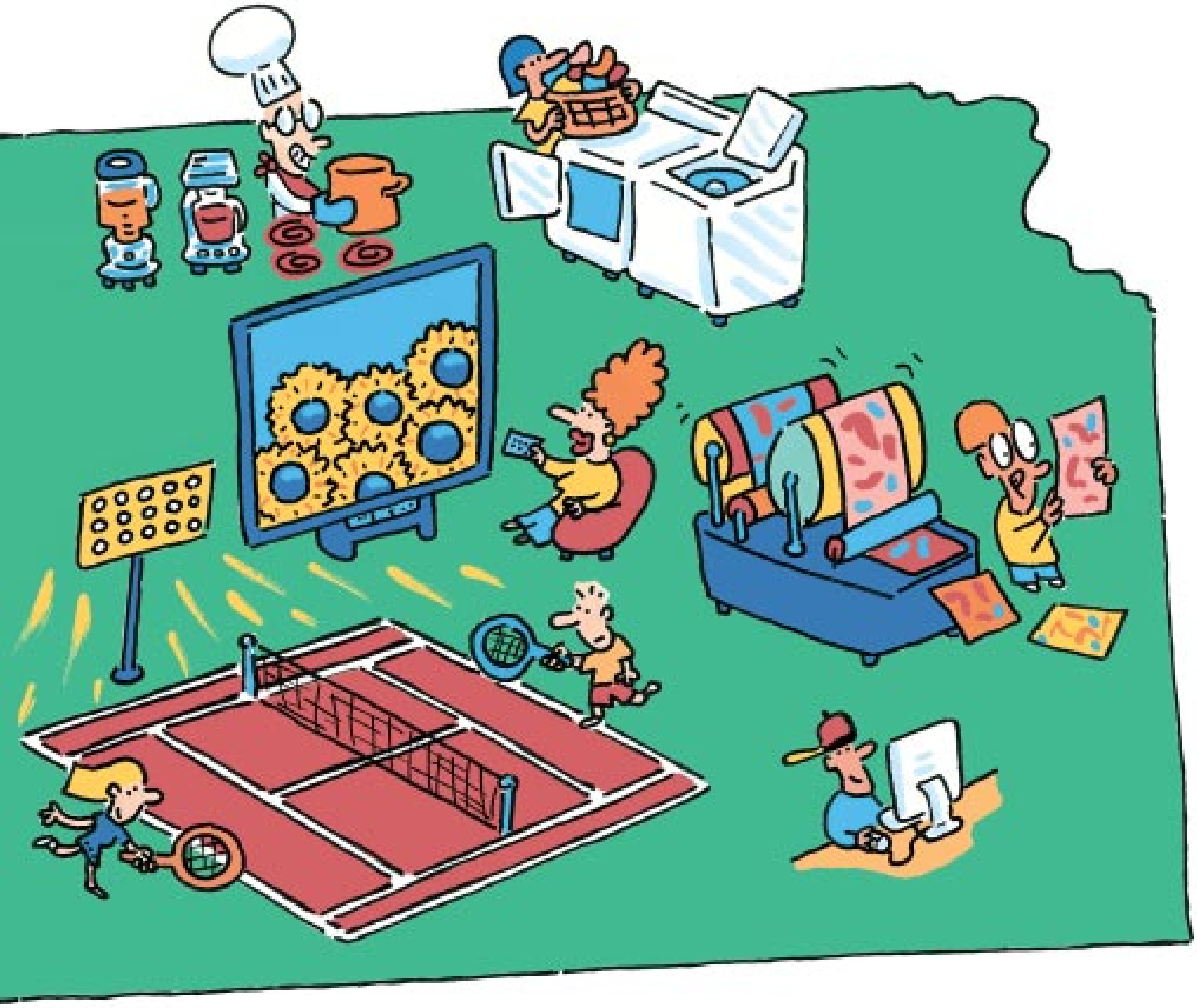


Cover illustration by Charlie Podrebarac, of Westwood, Kansas. Charlie has provided illustrations for the Westar Energy annual report the past four years. He has artfully captured the company's return to operating as a pure electric utility.

Dear Fellow Shareholder:

As reflected in our share price and in our financial statements, included in this report, we achieved very good financial results in 2006. Our total shareholder return from dividends and an increasing stock price was over 26%. And, as well, we took important steps to make new investments to provide for the future electricity needs of our Kansas customers.

In February 2007, we increased our indicated annual dividend per share to $1.08 from $1.00. At that time, our Board reiterated our dividend policy of paying out 60% to 75% of earnings, with a bias for being in the middle of that range and the upper half being possible only in extraordinary and non-recurring situations such as, for example, depressed earnings due to severely abnormal weather. Also in February, Standard & Poor's raised the ratings it assigns to our debt. That came on the heels of Moody's and Fitch also upgrading our credit ratings in 2006. All Westar debt rated by the three agencies now receives investment grade ratings, except corporate unsecured debt, which is rated BB+ by S&P.

We had an outstanding year in power generation. Our power plants operated at record levels to meet our customers' record peak demand of 4,822 MW on July 17. The new peak was 156 MW or 3.3% higher than the previous peak set in August 2003. That record was short-lived, however, as customer demand reached a new record 4,914 MW just two days later. These new peaks represent substantial growth in our customers' need for electricity. At forecasted rates of growth and to maintain contractually required generating reserve margins, we need to add in increments a total of about 900 MW of peaking capacity and about 600 MW of base load capacity by the middle of the next decade.

Our power generation employees met this new record output while also performing their jobs with the best annual safety performance in the history of our company. Our all-time low OSHA Recordable Accident Rate at our power plants of 0.77 meant that we had less than one injury for each 100 employees during the year. Based on OSHA statistics, our power plant employees are rated among the top 10% in safety. Our Jeffrey Energy Center achieved the distinction of being one of few industrial facilities to be nominated by OSHA for Star status in its Voluntary Protection Program, which is the highest level of OSHA safety recognition.

Our customer operations employees logged a 27% reduction in OSHA recordable injuries during 2006. Injuries requiring days away from work or resulting in job restrictions were at a historically low level placing our customer operations employees in the top quartile for comparable Edison Electric Institute transmission and distribution companies.

On October 31 we completed the acquisition of the 300 MW Spring Creek natural gas fueled plant in Oklahoma for $53 million. Attractively priced, we estimate that a new plant of similar size and type would have cost over $75 million more.

In late August we announced the construction of Emporia Energy Center, a 600 MW natural gas fueled peaking station with the first phase of 300 MW expected to begin service in the summer of 2008. The remaining 300 MW we expect to begin service in 2009. When completed we expect the total cost to be about $318 million.

We are also investing in substantial modifications to our existing coal fueled plants to comply with new environmental regulations under the Clean Air Act. We expect to invest about $745 million over the next seven to ten years on such equipment.

Wolf Creek, our 47% owned nuclear plant, established a new continuous run record of 506 days before it was taken off line in October to be refueled. The record long production run was followed by a record short 34-day refueling and maintenance outage.

On September 7, we announced plans to build a new 345 kilovolt high capacity transmission line from the Wichita area, northwest to Hutchinson and from there north to Salina. Following the announcement, we hosted open house meetings to gain insight from land owners along the potential routes for these lines. The information we gained from these meetings, along with other engineering and economic information, formed the basis of our formal application to the KCC in January 2007 for authority to construct the lines. These lines will substantially strengthen our transmission capability and will improve the reliability and economics of electric service in our service area and beyond.

Active summer and winter storm seasons for many of our neighboring utilities caused them to reach out to us for assistance to help them repair storm damaged equipment so that electric service to their customers could be restored. On two occasions last year we sent line crews to eastern Missouri. We also sent help to Oklahoma and western Kansas. Earlier this year, our neighbors in Nebraska requested our help. We were fortunate last year that our service area was largely free of damage from severe storms, but we know the day will come again when we need the same kind of assistance from others.

Part of meeting our customers' growing demand for electricity is to help them use it more wisely. In mid 2006 we launched an energy efficiency and conservation task force to identify several energy efficiency programs that we will initiate in 2007 and beyond.

We were pleased to again co-host the 23rd annual International Lineman's Rodeo. We are even more pleased to report that Westar is the home of the World Champion Journeyman Lineman team. Our team of three journeymen surpassed 200 teams from the U.S. and four other countries.

This year, as in recent years, we have included an essay with this Annual Report. This year's essay considers some of the implications for Westar of the current energy policy debate that is driven by climate change and long-term energy independence and security. We urge you to read it and if you have comments or questions about it to write or email us.

Thank you for your continued confidence.

Charles Q. Chandler IV
Chairman of the Board

James S. Haines, Jr.
President & CEO

Lessons Learned

By James Haines[1]

I. Purpose

The electric utility industry is now in the center of an energy policy debate that asks hard questions:

- Will we have enough electricity?
- What can we do to stop or limit climate change?
- How can we reduce dependence on foreign oil?

This debate comes as the industry has embarked on unprecedented investment in new power plants to satisfy continued growth in demand for electricity, modifying existing power plants to further improve air quality, and new transmission lines to expand and strengthen wholesale power markets.[2]

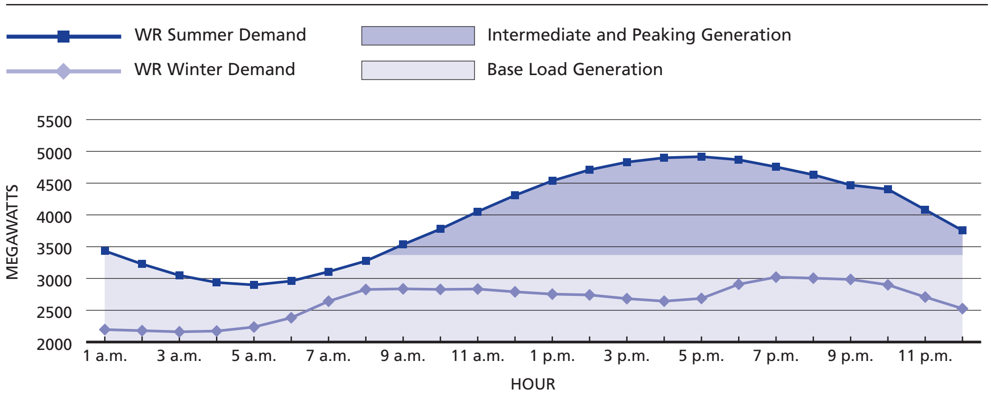
The last 30 years hold many examples of the difficulties inherent in establishing long-term electricity policy. Not least is that the investment cycle in a power plant can extend beyond 50 years while the life cycle of policies that affect power plants can be 10 years or less. Electric utilities' investors and customers pay dearly when policy is inconsistent with the practical exigencies of keeping the lights on. This essay will frame the nature of current energy policy debate and show its implications for Westar.

II. The Nature and Obligations of a Basic, Regulated Electric Utility

The Regulatory Compact

Electric utilities like Westar are granted state "certification" to be the exclusive provider of electricity in a specific area, and are legally obligated to provide safe, adequate, and reliable service at a regulated price to all within that area who will pay that price. In return, assuming regulators determine that its business has been prudently operated, the utility is given an opportunity to earn a profit comparable to that earned by other businesses having similar risks. This is often called the regulatory bargain or compact.

FIGURE 1 — Westar Typical Daily Load Profile



[1] Gina Penzig provided substantial research assistance. Mark Ruelle and James Ludwig provided significant comment. Robert Rives provided valued editorial assistance.

[2] Planned capital costs to comply with the Clean Air Interstate Rule and the Clean Air Mercury Rule are estimated at $47.8 billion from 2007 to 2025, without considering the cost of other federal, state and local mandates or possible carbon dioxide reduction mandates. Utilities invested $24 billion for emissions reduction equipment from 2002 to 2005. To meet the expected rise in demand for electricity, investments in power plants exceeding $275 billion will be required in the next 25 years. From 2006 to 2009, investment of $31.5 billion in transmission infrastructure is planned, a 60% increase over the previous five years. Investment in distribution systems is expected to average $14 billion per year over the next 10 years. Construction cost trends suggest these estimates are likely low; demand for resources has been driving project costs upward.

The Obligation to Plan for the Future

Fundamental to that compact is the utility's obligation to provide facilities necessary to meet customers' current and future electricity needs. Such facilities include primarily local distribution lines and equipment, high capacity transmission lines, and power plants. Here the focus will be on power plants. They require the most capital, consume the most resources, and present the widest array of choices.

Ideally, a utility's "mix" of power plants closely matches the pattern of its customers' demand for electricity — that is, how customer demand changes from one hour, day, or season to the next. **Figure 1** shows typical summer and winter daily demand curves for Westar's customers. The portion of demand that is constant for months at a time is served most efficiently with base load plants. These operate continuously. The portion of the load that occurs for only a few hours a day is served with peak load plants[3] that are engineered to be repeatedly started and stopped on short notice. Base plants are typically fueled with coal or uranium. They cost more to build than peak plants and take much longer to permit and construct, but their operating costs are usually lower. Peak plants are typically fueled with natural gas or oil.

Forecasting Risk

Because it can take as long as ten years to design, obtain necessary permits, and construct a base power plant — often costing more than $1 billion — utilities are substantially exposed to forecast risk. If regulators find that as a result of imprudent forecasting practices a utility has built too much power plant capacity or the wrong type, they can disallow recovery of all costs caused by the imprudent behavior.[4]

The Importance of an Interconnected High Capacity Transmission System

High capacity transmission lines move electricity from power plants to local distribution substations and lines. They serve other important functions as well. A well-interconnected transmission system is a key requirement for a vibrant wholesale electricity market, sharing power plant capacity reserves for use in emergencies,[5] and facilitating joint ownership in the construction of power plants.

FIGURE 2 — 2006 Generation by Fuel Type

All Units at Share. Excludes Spring Creek.

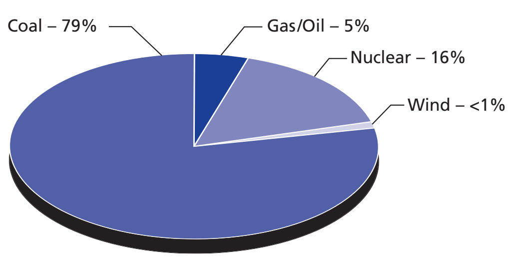
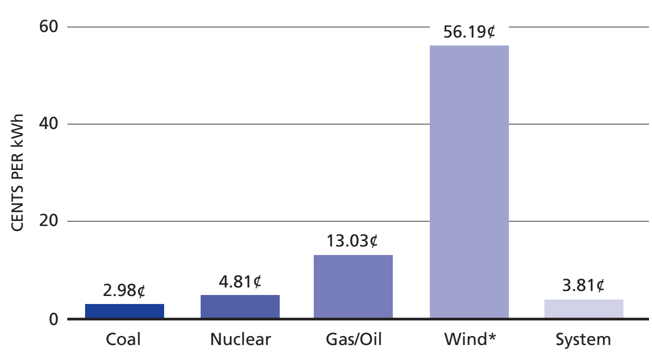


FIGURE 3 — 2006 Busbar Costs

All Units at Share. Excludes Spring Creek.



*Not representative of typical market costs. Market costs are about 5¢ to 8¢ per kWh before adjustments for tax incentives.

[3] Strictly speaking, there are three types of power plants: base, intermediate, and peak. For simplicity, since they have similar characteristics, intermediate plants are included here with peak plants.

[4] Because of their long lead-time, base power plants are particularly vulnerable to after the fact prudence reviews, if for no other reason than that policy and regulatory conditions can change dramatically in just a few years. Some states, including Kansas, permit or even require advance regulatory approval of power plants and thus offer some protection against second-guessing based on hindsight.

[5] Reserve capacity can be needed when equipment breaks down, growth in demand is greater than forecasted, the supply of power plant fuel is interrupted, transmission lines fail or are congested, or weather is extreme.

Consider just a few examples. At one point, utility "A" might be able to generate additional electricity at an incremental cost of, say, 2 cents per kilowatt hour when it costs utility "B" 3 cents. Through interconnected lines, A can sell to B at a negotiated price between 2 and 3 cents so both are better off. Or, consider that A and B each need a new 300 MW power plant. Each could build its own or, with interconnections jointly build one 600 MW plant and reduce costs by taking advantage of economies of scale. Or, utility "C" might own no power plants and thus must buy all the power needed by its customers. Through an interconnected system, both A and B might desire to sell to C, thus permitting C to purchase at a competitive price.

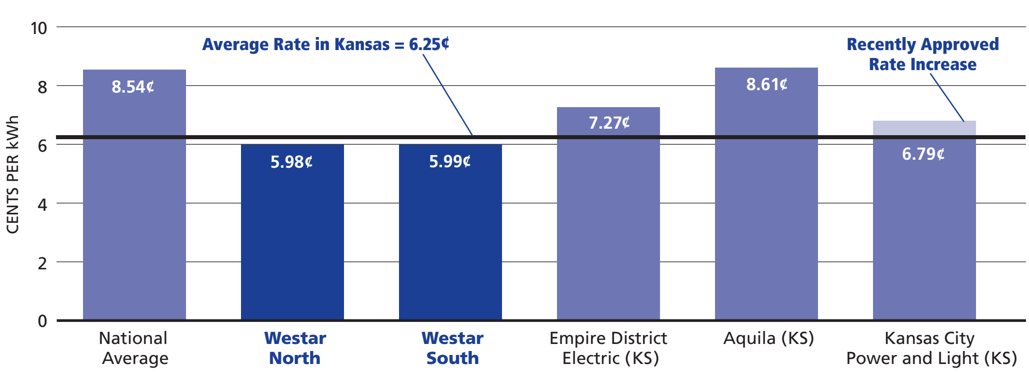
Those are basic examples. In reality, thousands of such transactions occur every hour of every day and can involve much greater complexity and many, many companies across broad areas. When the interconnected transmission system is not adequate to handle the transactions, inefficiencies result that can cost millions of dollars per year even for a small utility like Westar.

Westar's Power Plants, Their Reliability and Costs

Figure 2 shows Westar's sources of electricity by fuel type in 2006. **Figure 3** shows their average cost for capital, operations and maintenance, and fuel. **Figures 2** and **3** show that about 95% of the electricity Westar produces comes from its low cost, base plants fueled with coal or uranium. Importantly, in 2006 on average each of Westar's base plants was available 89% of the time[6] and some combination of them produced power 100% of the time. The economic benefits of Westar's generation mix are perhaps best shown in **Figure 4**. Westar's retail rates are about 30% below the national average and the lowest of any investor owned utility in Kansas.[7]

A seldom appreciated quality of a *system* of power plants is reliability. Anything short of 100% availability of electric power is failure. Few industries work to such a standard; few other commodities are as crucial to our way of life. Indeed, indirectly if not directly, shelter, water, and food depend upon electricity being continuously available.[8] Because there is no practical way to store electricity on a large scale, it must be generated virtually at the moment it is consumed, at the very moment of demand.[9]

FIGURE 4 — Attractive Retail Rate Comparison



Source: EEI July 1, 2006

[6] After accounting for the need to conserve coal in early 2006, this is top quartile performance.

[7] Apropos of a utility's obligation to plan for the future, Westar's low rates are due to coal and uranium fueled power plants built in the 1970's and early 1980's. Ironically, when Westar's nuclear plant, Wolf Creek, started operations in 1985 the Kansas Corporation Commission initially denied a return on 78% of KG&E's investment in Wolf Creek. While much of that return was eventually granted, it wasn't until after more than $100 million had been written off as a loss.

[8] Thus a utility must proceed with caution when considering unproven technology whose reliability can suffer for years as costly "kinks" are worked out.

[9] For that reason, wind generated power cannot eliminate the need for conventional power plants, it can only displace them when the wind is blowing just right which, in Kansas under ideal conditions, occurs randomly about 40% of the time.

Plans to Satisfy the Increasing Demand for Electricity by Westar Customers

From 1997 to 2006, the peak demand by Westar's customers grew from 3,808 MW to 4,805 MW, an annual compound growth rate of 2.6%. **Figure 5** shows the forecasted annual peak demand from 2007 to 2016 plus a contractually required reserve margin of at least 12%. Assuming that Westar adds no new capacity, **Figure 5** also shows Westar becoming capacity deficient in 2008. To address this, Westar plans to add capacity as shown by the light blue bars in **Figure 5**. The additions in 2008, 2009, 2011 and 2012 are natural gas fueled peak plants. The addition in 2014 is assumed to be a base plant. The anticipated cost of these additions is about $2 billion.

Figure 6 shows Westar's existing high capacity transmission lines and new lines it plans within the next five years. The estimated cost is about $180 million to $220 million.

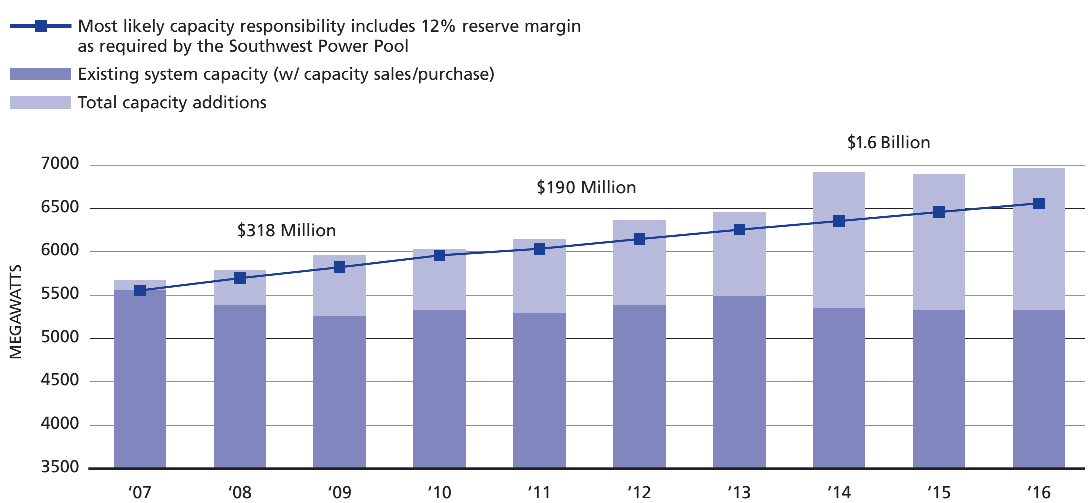
III. Electricity Policy Changes over the Last 30 Years

The Sky Is Falling

Electricity policy in the 1970's was shocked by four events. First, after a decade of apparent declines in natural gas supplies,[10] Congress passed the Power Plant and Industrial Fuel Use Act of 1978, immediately banning new gas fueled power plants and prohibiting its use in existing plants after 1989. Second, the Mideast oil embargoes of 1973 and 1978 ended the era of cheap oil and led to prolonged weakness in the economy. Third, orders for nuclear power plants halted after the 1979 accident at the Three Mile Island reactor. Fourth, annual growth in electricity demand fell from 7% plus, that had persisted for decades, to less than 3%.[11]

Despite the uncertainty this created, electric utilities remained legally obligated to meet current and future demand for electricity. In the late 1960's and early 1970's, they planned and started building coal and uranium fueled power plants not only to replace existing gas fueled plants but also to satisfy projected annual growth in demand of 7%. By the end of the 1970's, everything had turned upside down, with severe consequences for customers and shareholders alike.

FIGURE 5 — System Capacity



[10] In fact, gas was scarce because regulated prices for gas at the wellhead were held so low that gas exploration and production had become unprofitable.

[11] For long-term planning purposes, such a drop creates a dilemma. Is a one or two year decline an anomaly or a new trend?

From 1970 to 1985 the average retail price per kWh of electricity increased from 1.86 to 6.47 cents. Market prices of utility stocks fell from well above book value to slightly less than 75% of book value in 1981. Many companies dropped from A or better credit quality to BBB or lower. Regulators disallowed from rate recovery over $11 billion in capital invested in new power plants.[12]

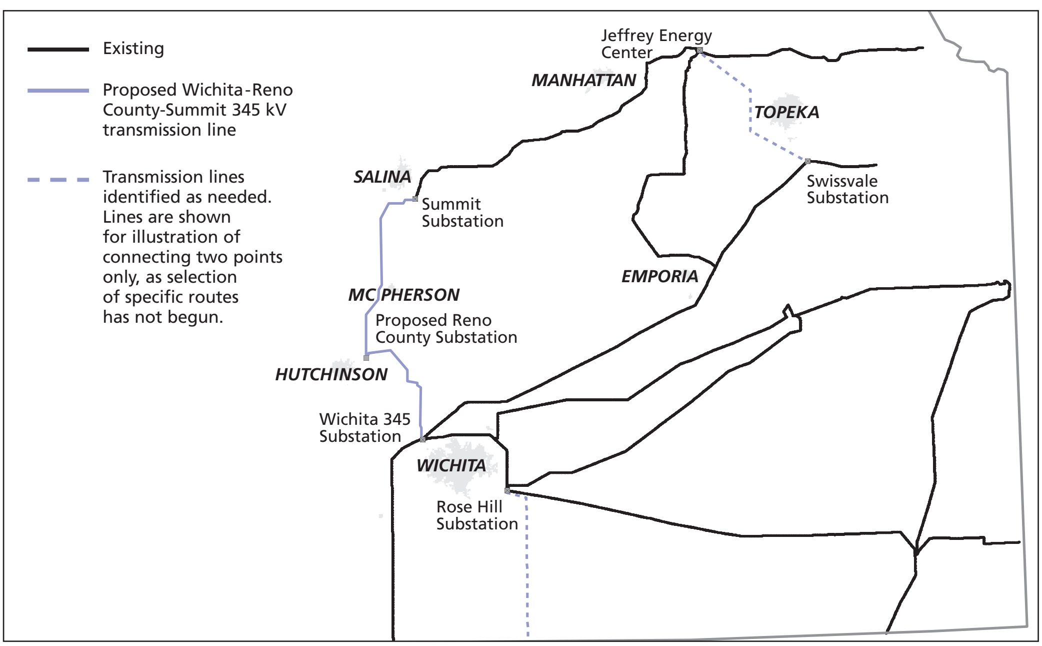
By the mid 1980's, natural gas had done an about face. Its predicted disappearance became a glut once its wellhead price was deregulated and producers could charge a price that compensated for the costs and risks of exploring for and producing it. The Power Plant and Industrial Fuel Use Act was repealed. Clearly, energy policy from the 1970's and early 1980's caused some painfully expensive failures. Ironically, one significant success, re-establishing plentiful and relatively inexpensive gas supplies, ultimately led to colossal failure.

The Grass Is Greener

The return of cheap and plentiful natural gas in the 1990's brought the illusion that electric utilities had been wrongheaded in converting to coal and uranium fueled power plants in the 1970's and early 1980's. The cost of electricity from new state of the art natural gas fueled plants was, for the time being, significantly lower. Entrepreneurs eagerly built them. Companies like Enron were ready to create new, competitive electricity markets, but only if policy makers would free them from bureaucratic price regulation.

Academic theorists and large industrial consumers seeking lower rates led policy makers to view regulation as at best a sub-optimal way to set electricity prices. An unregulated, competitive *retail* market surely would be better. The market would deal swiftly with imprudent, inefficient managers. The best managers would be amply rewarded, and customers would see quick, big benefits from better prices and service. California and 16 other states set out for the Promised Land.

FIGURE 6 — 345 kV Transmission Lines



[12] In the longrun, those plants have proven themselves as reliable and low cost producers of power.

The Grass Is Not

There is no need to dwell on the results. One California utility was driven into bankruptcy, another nearly so. Customers were left holding a hugely expensive mess. In no state that moved to retail competition for electricity has the promise of lower rates come true.[13] In most, rates have risen sharply. In many cases, perhaps in every case, the legislatively mandated path to retail competition was flawed. Certainly, in theory retail competition should work. But in practice to date, it has failed.[14] This failure cannot be attributed to acts of God, unforeseeable events, or uncontrollable acts of foreign sovereigns.

IV. Issues Now Driving Electric Energy Policy Debate

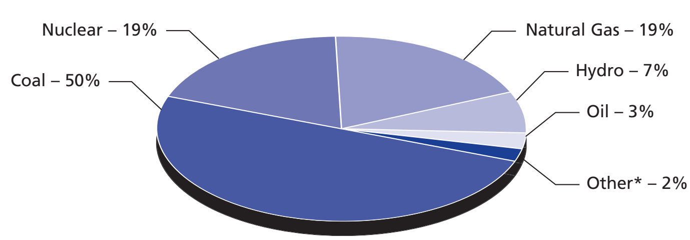
The Sky Is Really Falling?

Figure 7 shows the sources of electricity generated in the U.S. Many people believe the amount of electricity generated by coal makes that chart a gloomy picture. Forget that, at the present rate of use and with present technology, there is within the continental U.S. more than a 200-year supply of coal. Generating with coal, while far cleaner than it once was, is still dirty from the mine to the stack. Burning coal to make electricity releases substantially more legally defined pollutants into the atmosphere than burning natural gas or oil: NOx (nitrogen oxide), SO_2 (sulphur dioxide), Hg (mercury),[15] CO (carbon monoxide), and PM (particulate matter).

Figure 8 shows the major sources for each of those pollutants in 2001. Since 1985, the electric power industry has reduced the most significant emissions, NOx and SO_2, from power plants by 48% and 55%, respectively. By 2015 the reduction of these pollutants is predicted to reach 80% and 88%. *Importantly, from 1985 to 2015 the Energy Information Agency estimates that electricity production will increase by 90%.* Still, with present technology, such pollutants, at some level, remain a fact of life for coal-fueled plants.

Increasingly, however, concerns with burning fossil fuels, especially coal, have focused upon the release of CO_2 (carbon dioxide).[16] Many believe CO_2 accumulation in the atmosphere, along with other "greenhouse gasses,"[17] is a principal

FIGURE 7 — National Fuel Mix



Source: U.S Department of Energy, Energy Information Administration (EIA), 2005 preliminary data

*"Other" includes generation by agriculture waste, batteries, chemicals, geothermal, hydrogen, landfill gas recovery, municipal solid waste, purchased steam, solar, sulfur, wind and wood.

[13] Some have argued, albeit unpersuasively and with tortured analysis, that continued regulation would have produced even higher prices.

[14] In the same time period, a competitive wholesale market was developing. For a variety of reasons, wholesale competition has largely worked to the benefit of customers and shareholders.

[15] The EPA estimates that 87% of the mercury deposited in the United States is from international sources.

[16] Fossil fuel power plants account for about 41% of CO_2 releases in the U.S. Vehicles account for about 33% of such releases. The second most abundant greenhouse gas, methane, has 21 times more heat trapping capacity than CO_2. Methane is released from diverse sources such as rice paddies and animal digestive processes, sources far harder to regulate than power plants or vehicles.

[17] Naturally occurring and manmade greenhouse gases, for examples, include water vapor, carbon dioxide, methane, nitrous oxide, ozone, hydrofluorocarbons, and sulfur hexafluoride. Greenhouse gases insulate our planet and, thereby, make life as we know it possible. The concern is that a disproportionate accumulation of greenhouse gases, i.e. too much insulation, will lead to overheating the planet.

contributor to, if not the sole cause of, climate change.[18] Notably, the EPA has not yet determined CO_2 to be a pollutant and its emission is not subject to regulation.[19]

Many people believe the slice of the pie chart in **Figure 7** taken by nuclear is as grim a picture as the slice taken by coal. They cite the terrible consequences that could follow if highly radioactive material were to be released from a U.S. nuclear plant or from radioactive materials in transit. It is of no comfort, they say, that there is only the slightest chance of such a thing happening and an even slighter chance of an ensuing threat to public safety. And even if all the plants run flawlessly, we still, they say, have to safely store radioactive waste from such plants for thousands of years.

Energy Independence

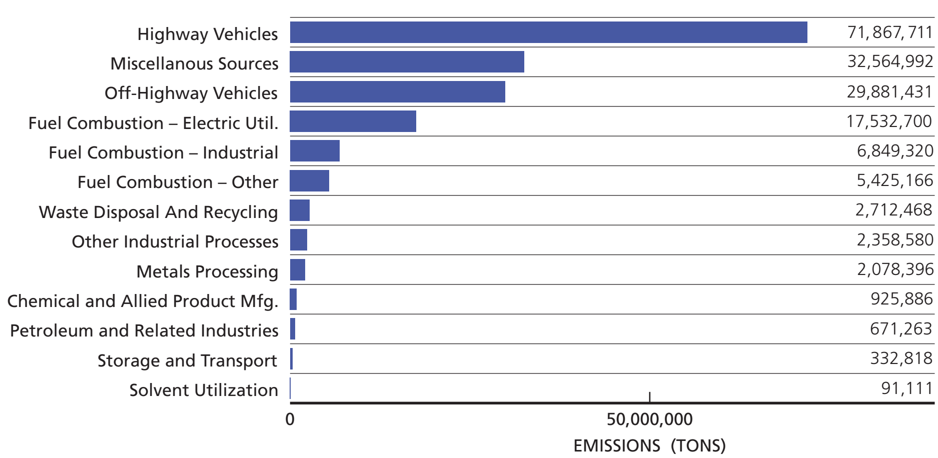
Debate about energy independence is focused almost exclusively on oil. In 2005, 60% of oil consumed in the U.S. was from foreign sources. The U.S. consumes 7.5 billion barrels of oil annually. Transportation consumes 68% while electricity production consumes just 3%. The National Resources Defense Council has estimated that oil consumption can be reduced 40% by 2025 through greater use of bio-fuels, electric vehicles, and increased efficiency.

Current Electricity Policy Debate

"Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global mean sea level. Most of the observed increase in globally averaged temperatures since the mid 20th century is very likely due to the observed increase in anthropogenic greenhouse gas concentrations. Discernible human influences now extend to other aspects of climate, including ocean warming, continental-average temperatures, temperature extremes and wind patterns," according to the Intergovernmental Panel on Climate Change report released February 2, 2007.[20]

FIGURE 8 — Pollutant Emissions

Total emission for 2001 for each category is a combination of the air pollutants CO, NOx, PM10, PM2.5 and SO_2 which are regulated under the Clean Air Act. Mercury is regulated under the Clean Air Mercury Rule. In 1999, the most recent year for which information is available, of the 144 tons of mercury deposited in the United States, 11.1 tons was from U.S. utilities. Under current laws that amount will reduced to about 3.4 tons by 2018.



Source: US EPA Office of Air and Radiation, NEI Database. Edison Electric Institute.

[18] "Climate change is the single greatest environmental challenge facing the world today. Scientists overwhelmingly agree that the global community must reduce emissions of greenhouse gases, including CO_2, to well below 1990 level within a few decades, if we are to stabilize the climate at acceptable levels." December 15, 2006, letter from the Attorneys General of eight states to the Kansas Department of Health and Environment protesting the proposed construction of three 700 MW coal fueled power plants in western Kansas by Sunflower Electric Power Corporation. In contrast: "Even a complete ban on burning fossil fuels in the U.S. wouldn't halt progress to the next milestone, a doubling of atmospheric carbon dioxide since the advent of civilization. No joke to say the only live question for congresspersons and their voters back home is: How much are we going to spend to have no impact on global warming, and why?" Holman Jenkins, "Decoding Climate Politics," THE WALL STREET JOURNAL, 1/24/07, at A12.

[19] In Massachusetts v. EPA this question is pending before the U.S. Supreme Court.

[20] For an excellent summary of the problem and potential solutions see: "Energy's Future Beyond Carbon," Scientific American, September 2006 Special Issue.

Even before release of that report, political leaders in the U.S. were making almost daily calls for legislation and regulations to reduce CO_2 emissions, to sharply curtail construction of new coal plants, and to aggressively accelerate programs to conserve electricity and use it more efficiently. A few states and even cities have enacted laws that attempt to limit CO_2 emissions.

Congressional leaders have pledged to pass major legislation dealing with climate change and energy independence. In a January 18, 2007, news release, Speaker Pelosi stated: “For America to be safe and strong, we must take further decisive action now to free our country of its dependence on foreign energy sources and to confront the rising tide of global warming. … We hope to have legislation on global warming and energy independence through the committees by July 4th. …”

Policy Debate And Reality: Collision Or Convergence?

Electricity plays an ever more essential role in every aspect of contemporary life. As a practical matter, any electricity policy that would degrade electricity’s reliability or supply will fail.

Many people assert that renewable sources of electricity, primarily wind and solar, coupled with conservation and efficiency, can eliminate the need for new coal or nuclear plants.[21] In 2005, 9%, about 1 of every 11 kWh, of electricity consumed in the U.S. came from renewable resources. Total electricity generated in the U.S. in 2005 was 4,025 billion kilowatt hours. It is estimated that by 2030 electricity consumption in the U.S. will grow 44% to 5,788 billion kWh. The EPA estimates that by 2025 conservation and efficiency can cut projected demand by 20%. As **Figure 9** shows, even the leading forms of renewable sources of electricity were a tiny portion of installed U.S. generation capacity at the beginning of 2006. Perhaps this is why reliable cost information is elusive. However, even wind, which is identified as one of the lower cost sources, is about 5 to 8 cents per kilowatt hour – well above the 2.98 cents per kWh for Westar’s coal-fueled generation in 2006. **Figure 10** shows their annual capacity factor, that is, the amount they actually produce relative to what they would produce if they operated continuously at full capacity.

Figure 9, when compared with **Figure 7,** illustrates another important fact. Because conventional sources of electricity are generally more reliable than renewable sources, they account for a larger portion of actual energy production (fuel mix) than implied by their share of total capacity.

FIGURE 9 — Nameplate Capacity by Source

Source: Energy Information Administration

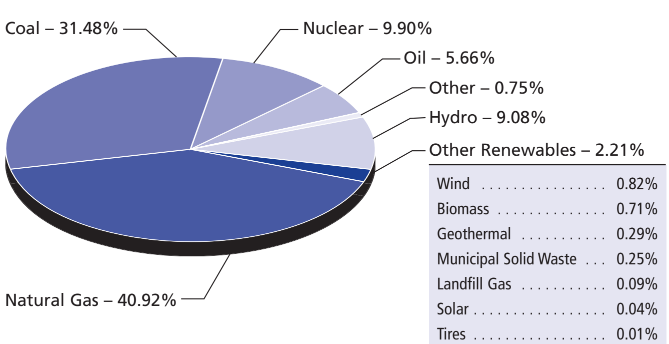
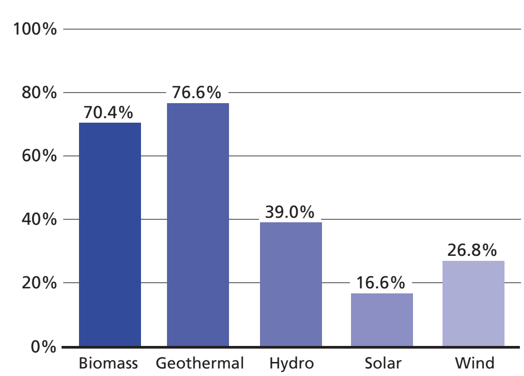


FIGURE 10 — Proven Renewables Capacity Factor

Source: Energy Information Administration



[21] Typically when we think of conservation and efficiency we have in mind the use of energy by end users, i.e. retail customers, whether residential, commercial or industrial. In fact, the greatest potential for efficiency gains is in the power plants themselves. It is estimated that a 2% increase in the efficiency of coal-fueled power plants would exceed all additional renewable power generation through 2030.

Now, while capacity factor is an industry-accepted measurement for reliability for most forms of generation, wind and solar energy present special challenges because regardless of how well maintained the plant is, it only produces electricity when the wind blows or the sun shines. For example, while a coal or gas fueled plant, even a plant fueled by biomass, can be predictably put in operation when need is highest, sufficient wind must blow to produce electricity with a wind turbine; a requirement beyond control of the operator.

Figure 11 shows the output of electricity from the two wind farms in Kansas that were operational on July 17, 2006, a day Westar Energy's customers set a record with their demand for electricity. In the early evening as the need for electricity rose, output from these wind farms dropped. Without other resources, residents would have come home in mid-summer heat without adequate energy to cool and light their homes or prepare evening meals.

At the end of 2006, 23 states and the District of Columbia had laws or regulations requiring a certain percentage of electricity to come from renewable sources by a certain date. For example, Texas law requires 2,000 MW of renewable energy by 2009. In 2006, Arizona and New Jersey increased their renewable requirement to 15% of electricity production by 2015 and 20% by 2020.

Uranium and coal are the most abundant sources of energy within U.S. boundaries. They accounted for 69% of electricity generated in the U.S. in 2005. As a practical matter, any electricity policy that does not include coal and uranium will fail.

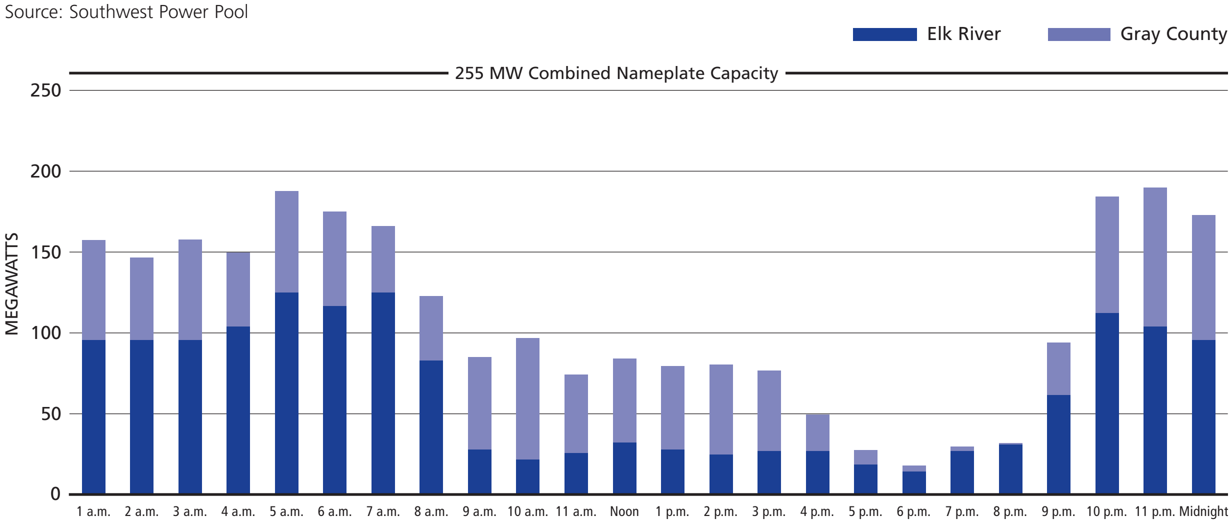
While in theory a coal plant can emit virtually no pollutants or CO_2, no such plants exist today.[22] New technology often goes through a trial and error period; this process of working out the "kinks" inevitably increases costs and degrades reliability.

If CO_2 is a major contributor to climate change, then any energy policy that does not directly address CO_2 emissions will fail.[23]

If the reduction or elimination of CO_2 emissions is mandated, there will be significant increases in the price of electricity and other forms of energy.

FIGURE 11 — Wind Farm Output July 19, 2006

Source: Southwest Power Pool



[22] The FutureGen Alliance aims to build the world's first fossil-fueled zero-emissions power plant. The 275 MW plant will produce both electricity and hydrogen. The project was launched in 2005 and is currently in the site selection stage. It is scheduled to begin operation in 2012.

[23] Capturing and storing meaningful quantities of CO_2 is a vastly different and separate technical challenge from designing and building a coal-fueled power plant that is "capture" ready.

Fossil fueled power plants are not the only sources of greenhouse gas emissions. Any energy policy, to be successful, must address all major sources, not just power plants. While all CO_2 emitters should be proportionately covered by a policy, it is important to recognize that carbon emissions from some sources can be reduced less expensively than from others. Accordingly, a policy should be flexible enough to permit reduction or offset so the greatest reductions are achieved at the lowest cost.

Nuclear power plants produce no air emissions. No new nuclear plants have been started in the U.S. since the late 1970's.[24] Through a tax on nuclear generated electricity, the Department of Energy has collected $28 billion for a radioactive waste facility that, by law, was to be operating by 1998. That facility, in Nevada, is nothing more than a glorified hole in the ground and is years, if not decades, from opening. Some say it will never open. Some say there will be no new nuclear plants until such a facility is open.

Conventional wisdom is that conservation and efficiency are a function of price: as electricity becomes relatively more expensive, more substitutes for electricity become economically viable.[25] Many new programs to encourage conservation and efficiency are being tried throughout the U.S. It remains to be seen if they can dramatically reduce, let alone eliminate, the need for new coal and uranium power plants.

Nonetheless, conservation and efficiency simply are not sources of electricity. They can make existing sources go further and, therefore, deserve an important place in electricity policy. But even if every viable conservation and efficiency practice is implemented to its maximum extent there will remain a need for electricity and eventually for new power plants.

It is not unreasonable to think that, if conservation and efficiency and renewable electricity sources are economic, entrepreneurs will bring them to market without a legal mandate. The need for a legal mandate suggests they are not economic in all cases. That in turn suggests that as such mandates are satisfied, electric rates will increase.

Energy conservation and efficiency can achieve short-term gains to buy the time necessary to develop clean coal technology and permanent radioactive waste disposal facilities.[26]

It is a little appreciated fact that as we have become more efficient in extracting energy sources (e.g. coal, oil, gas, uranium), more efficient in converting those sources to electricity, and more efficient in using electricity, *we have used more electricity, not less!*[27] For those counting on conservation and efficiency as part of a long-term solution, that should be sobering.

Final Thoughts

Electricity policy, ultimately, will succeed or fail based on the choices of those who use electricity. When a utility, such as Westar, announces it needs a new power plant, it reflects the myriad choices its customers have made and, importantly, is complying with its legal obligation to satisfy the electricity demands that result from those choices.

One customer choice that has been very nearly universal is *100% reliability at low rates.* Thus, when a utility builds a coal fueled plant instead of wind powered plants, it is not reflecting a preference for coal over wind, rather it is reflecting its

[24] While there is much talk about a resumption of nuclear plant construction and while significant amounts are being invested in new designs and while the Nuclear Regulatory Commission has made the licensing process more rational, there have been no ground breaking ceremonies.

[25] The irony here is that if regulators and policy makers have proven resistant to anything it is to increasing the price of electricity.

[26] Reprocessing (recycling) spent nuclear fuel to "harvest" its unused energy would reduce the volume of waste needing to be permanently stored and would significantly increase the supply of nuclear fuel to make electricity. Other countries, France and Japan for example, reprocess nuclear fuel. The U.S. stopped reprocessing nuclear fuel in the late 1970's. Opposition to reprocessing is generally based on the fact that one of its by-products, plutonium, while it can be used as reactor fuel, also can be used in weapons.

[27] See Huber and Mills, The Bottomless Well, Chap. 7, "The Paradox of Efficiency", pp. 108 – 123, Basic Books (2005). For example, "Efficiency may curtail demand in the short term, for the specific task at hand. But its long-term impact is just the opposite. When steam-powered plants, jet turbines, car engines, light bulbs, electric motors, air conditioners, and computers were much less efficient than today, they also [in the aggregate] consumed much less energy. The more efficient they grew, the more of them we built, and the more we used them – and the more energy they consumed overall. Per unit of energy used, the United States produces more than twice as much GDP today as it did in 1950 – and total energy consumption in the United States has risen three-fold." Id. at 111. Perhaps an example from another technology is more illustrative. According to Moore's Law, the power of computer processors doubles about every 18 months. As computer processing has followed Moore's Law and become more efficient, the demand for computers has increased exponentially. "Power consumption of server systems doubled between 2000 and 2005, requiring the generating capacity of about 14 power plants world-wide." The Wall Street Journal, 2/15/07, at B3. Also, to the extent that electricity plays a role in achieving energy independence, for example to fuel electric vehicles, the demand for electricity will increase.

customers' choices for a form of power generation that is reliable and low cost versus a form that is diametrically opposite. If and when wind powered plants alone or in combination with some other form of generation match the reliability and cost of coal fueled plants, they will no doubt be preferred.

Climate change is a global problem. Certainly, first world countries, like the U.S., should assume proportionate leadership responsibility in seeking and implementing appropriate solutions. A grand solution is unlikely. More likely the solution will come in many steps and places and be hugely complex and vulnerable to unintended consequences.

Data show conclusively that over long periods, measured in epochs, average global temperatures rise and fall, sometimes dramatically and rapidly. For the time life has been present on our planet, it has adapted to these climate changes. Adaptation should not be ruled out as at least part of the response to climate change.

Generating, transmitting, and distributing electricity, as well as extracting and transporting the fuels used in power plants, are fraught with potential hazards. But when the good that comes from electricity[28] is considered, it is decisively not a devil's bargain that we choose electricity, while working diligently to minimize the potential of those hazards.

What is the place of electric utilities in forming energy policy? Certainly, electric utilities, along with others, should be sources of information necessary to inform the debate. And certainly, electric utilities will participate as advocates in the debate. But this is not a debate and not a policy that should be dominated by one or any collection of interest groups. It should be dominated by sound science and objective engineering and economic information.[29]

Where sound science and objective information reveal a solution, policymakers must have the courage to impose it. For example, developing a radioactive waste facility or imposing conservation and efficiency standards should not be held hostage by parochial or "not in my back yard" interests.

It will not work for policy to be established one utility, one state or one region at a time. A patchwork approach will only result in a crazy quilt that might look good but will keep no one warm.

As recounted, recent electricity policy has not uniformly succeeded and at times has been a downright failure. This has not always been due to flawed policy. Often it has been due to many moving parts over which no individual or entity has control and about which there can be no clairvoyance.

Conclusion

On balance, utilities that have been most successful during periods of policy change and turmoil have been those that stayed closest to their basic mission of providing safe, reliable, high quality electric service at a reasonable cost. Ironically, the policy experiment with deregulation drove affected utilities away from that basic mission toward diversification. We at Westar have worked single mindedly over the last four years to return to basics. By any measure we have succeeded. We are well prepared to deal with anticipated changes in electricity policy and, at the same time, "keep the lights on" for the benefit of customers and shareholders alike.

[28] While it is not without issues, electricity is by far the cleanest and most productive form of energy ever put to use by man.

[29] California's debacle with deregulation has been attributed to a fundamentally flawed deregulation law that was a product of the appeasement of the various interest groups that participated in the legislative process. On the scales of social, economic, moral, and political difficulty, regulating California energy markets should have been child's play compared with the geo social, economic, moral, and political complexities of reversing climate change.

Financial Measures 2006:

	2006	2005
FINANCIAL DATA *(Dollars in Millions)*		
INCOME HIGHLIGHTS		
Sales	**$1,606**	$1,583
Income from continuing operations	**165**	135
Results of discontinued operations, net of tax	**—**	1
Earnings available for common stock	**164**	135
BALANCE SHEET HIGHLIGHTS		
Total assets	**$5,455**	$5,210
Common stock equity	**1,539**	1,416
Capital structure:		
Common equity	**49%**	45%
Preferred stock	**1%**	1%
Long-term debt	**50%**	54%
OPERATING DATA		
Sales (Thousands of MWh)		
Retail	**19,558**	19,217
Wholesale	**7,418**	8,440
Customers	**669,000**	660,000
COMMON STOCK DATA		
PER SHARE HIGHLIGHTS		
Earnings per share:		
Basic earnings available from continuing operations	**$1.88**	$1.54
Discontinued operations, net of tax	**—**	$0.01
Basic earnings available	**$1.88**	$1.55
Dividends declared per common share	**$1.00**	$0.92
Book value per share	**$17.61**	$16.31
STOCK PRICE PERFORMANCE		
Common stock price range:		
High	**$27.24**	$24.97
Low	**$20.09**	$21.07
Stock price at year end	**$25.96**	$21.50
Average equivalent common shares outstanding (in thousands)	**87,510**	86,855
Dividend yield (based on year end annualized dividend)	**3.9%**	4.3%

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, 2006

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 $1,834,449,044 at June 30, 2006.

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	**87,494,258 shares**
(Class)	(Outstanding at February 15, 2007)

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 2007 Annual Meeting of Shareholders	Part III (Item 10 through Item 14) (Portions of Item 10 are not incorporated by reference and are provided herein)

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FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Annual Report on Form 10-K are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we "believe," "anticipate," "target," "expect," "pro forma," "estimate," "intend" and words of similar meaning. Forward-looking statements describe our future plans, objectives, expectations or goals. Such statements address future events and conditions concerning matters such as, but not limited to: amount, type and timing of capital expenditures; earnings; cash flow; liquidity and capital resources; litigation; accounting matters; possible corporate restructurings, acquisitions and dispositions; compliance with debt and other restrictive covenants; interest rates and dividends; environmental matters; regulatory matters; nuclear operations; and the overall economy of our service area.

What happens in each case could vary materially from what we expect because of such things as: regulated and competitive markets; economic and capital market conditions; changes in accounting requirements and other accounting matters; changing weather; the ultimate impact of the remand by the Kansas Court of Appeals to the Kansas Corporation Commission arising from appeals filed by interveners of portions of the December 28, 2005 rate Order; the impact of regional transmission organizations and independent system operators, including the development of new market mechanisms for energy markets in which we participate; rates, cost recoveries and other regulatory matters including the outcome of our request for reconsideration of the September 6, 2006 Federal Energy Regulatory Commission Order; the impact of changes and downturns in the energy industry and the market for trading wholesale energy; the outcome of the notice of violation received on January 22, 2004 from the Environmental Protection Agency and other environmental matters including possible future legislative or regulatory mandates related to carbon dioxide emissions and climate change; political, legislative, judicial and regulatory developments at the municipal, state and federal level that can affect us or our industry; 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; the impact of changes in interest rates on pension and other post-retirement and post-employment benefit liability calculations, as well as actual and assumed investment returns on pension plan assets; the impact of changes in estimates regarding our Wolf Creek Generating Station decommissioning obligation; changes in regulation of nuclear generating facilities and nuclear materials and fuel, including possible shutdown or required modification of nuclear generating facilities; uncertainty regarding the establishment of interim or permanent sites for spent nuclear fuel storage and disposal; homeland security considerations; coal, natural gas, uranium, oil and wholesale electricity prices; availability and timely provision of equipment, supplies, labor and fuel we need to operate our business; and other circumstances affecting anticipated operations, sales and costs.

These lists are not all-inclusive because it is not possible to predict all factors. This report should be read in its entirety. No one section of this report deals with all aspects of the subject matter. Any forward-looking statement speaks only as of the date such statement was made, and we are not obligated to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made except as required by applicable laws or regulations.

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 669,000 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

New Generation and Transmission Construction Plans

We plan significant increases in investments in new generation, new transmission and air emission controls at existing fossil-fueled power plants. These investments include new projects and higher investment estimates for previously announced projects, which have increased due to rising prices of labor, materials and supplies.

In August 2006, we announced plans to build a new natural gas-fired combustion turbine peaking power plant near Emporia in Lyon County, Kansas. We expect the new plant, which we have named the Emporia Energy Center, to have an initial generating capacity of up to 300 megawatts (MW), with additional capacity to be added in a second phase, bringing the total capacity to approximately 600 MW. We expect the total investment in the plant to be about $318 million. We plan to begin construction on the new plant in the spring of 2007. The initial phase of the plant is scheduled to begin operation in the summer of 2008.

In September 2006, we announced plans to build a transmission line from our Gordon Evans Energy Center northwest of Wichita, Kansas, to a new substation near Hutchison, Kansas, then onto our Summit substation near Salina, Kansas, a distance totaling approximately 86 miles. In January 2007, we filed an application with the Kansas Corporation Commission (KCC) to request permission to build the line. Kansas law requires the KCC to issue an order within 120 days of our filing regarding our application. If the KCC issues a permit for us to proceed, we expect to complete construction in 2009. Our preliminary cost estimate for the project is $80 million to $100 million. This estimate could change materially as engineering and construction proceed. In addition to this line, we plan additional expansions to our electric transmission network in Kansas. These include a new line from our Rose Hill substation near Wichita to the Kansas-Oklahoma border, where we expect to interconnect with new facilities built by an Oklahoma-based utility, and a new line from our Jeffrey Energy Center to an existing substation about 15 miles south of Topeka, Kansas.

In May 2005, we initiated a study to identify potential sites suitable for a new coal-fired power plant. We said that we intended to ultimately select and announce the preferred site for a base load coal plant by the end of 2006. Due primarily to the significant increase in the estimated costs of constructing such a facility, in December 2006, we announced that we would delay making such a decision. We continue to evaluate how we will meet our future base load capacity needs.

During 2005 and 2006 we announced plans to make significant investments in our coal plants to reduce air emissions from these plants. The estimated costs of those investments have increased since those earlier announcements. For additional information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Future Cash Requirements."

Changes in Rates

In accordance with a 2003 KCC Order, on May 2, 2005, we filed applications with the KCC for it to review our retail electric rates. On December 28, 2005, the KCC issued an order (2005 KCC Order) authorizing changes in our rates, which we began billing in the first quarter of 2006, and approved various other changes to our rate structures. In April 2006, interveners filed appeals with the Kansas Court of Appeals challenging various aspects of the 2005 KCC Order. On July 7, 2006, the Kansas Court of Appeals reversed and remanded for further consideration by the KCC three elements of the 2005 KCC Order. The balance of the 2005 KCC Order was upheld.

On February 8, 2007, the KCC issued an order in response to the Kansas Court of Appeals' decision regarding the 2005 KCC Order. In its February 8, 2007 Order the KCC: (i) confirmed its original decision regarding its treatment of the La Cygne unit 2 sale-leaseback transaction; (ii) in lieu of a transmission delivery charge, ruled that it intends to permit us to recover our transmission related costs in a manner similar to how we recover our other costs; and (iii) reversed itself with regard to the inclusion in depreciation rates of a component for terminal net salvage. The February 8, 2007 KCC Order requires us to refund to our customers the amount we have collected related to terminal net salvage. We have recorded a regulatory liability at December 31, 2006 in the amount of $16.4 million related to this item. For additional information, see Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation."

OPERATIONS

General

Westar Energy supplies electric energy at retail to approximately 360,000 customers in central and northeast Kansas and KGE supplies electric energy at retail to approximately 309,000 customers in south-central and southeastern Kansas. We also supply electric energy at wholesale to the electric distribution systems of 45 cities in Kansas and four electric cooperatives in Kansas. We have other contracts for the sale, purchase or exchange of wholesale electricity with other utilities. In addition, we engage in energy marketing and purchase and sell wholesale electricity in areas outside our retail service territory.

In 2006, we implemented a retail energy cost adjustment (RECA) that allows us to recover the cost of fuel consumed in generating electricity and purchased power needed to serve our customers. Through the RECA, we bill our customers on a month ahead estimate. The RECA then provides for an annual review and reconciliation of estimated and actual fuel and purchased power costs. The annual review also affords the KCC a means to determine the prudence of our fuel and purchased power expenses. If the KCC determines any expenses are imprudent, it will likely disallow recovery of those costs.

Generation Capacity

We have 6,033 MW of accredited generating capacity, of which 2,587 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	3,286.0	54.5
Nuclear	548.0	9.1
Natural gas or oil	2,117.0	35.1
Diesel fuel	81.0	1.3
Wind	1.2	—
Total	6,033.2	100.0

Our aggregate 2006 peak system net load of 4,914 MW occurred on July 19, 2006. Our net generating capacity, combined with firm capacity purchases and sales, provided a capacity margin of 11% above system peak responsibility at the time of our 2006 peak system net load.

Under wholesale agreements, we provide generating capacity to other entities 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
Oneok Energy Services Co.	75	December 2015
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 2006, we provided approximately 78 MW to, and received approximately 179 MW from, McPherson. The amount of base load capacity provided to McPherson is based on a fixed percentage of McPherson's annual peak system load.*

Fossil Fuel Generation

Fuel Mix

The effectiveness of a fuel to produce heat is measured in British thermal units (Btu). The higher the Btu content of a fuel, the less fuel it takes to produce electricity. We measure the quantity of heat consumed during the generation of electricity in millions of Btu (MMBtu).

Based on MMBtus, our 2006 fuel mix was 79% coal, 16% nuclear and 5% natural gas, oil and diesel fuel. We expect that our fuel mix in 2007 will have a higher percentage of uranium usage because we do not have a scheduled outage at Wolf Creek in 2007. 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 2,190 MW, of which we own an 84% share, or 1,839 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 for those quantities over the scheduled annual minimum will occur in 2008.

The Burlington Northern Santa Fe (BNSF) and Union Pacific railroads transport coal for Jeffrey Energy Center from Wyoming under a long-term rail transportation contract. The contract term continues through December 31, 2013. The contract price is subject to price escalation based on certain costs incurred by the rail carriers. We expect increases in the cost of transporting coal due to higher prices for the items subject to contractual escalation.

The average delivered cost of coal burned at Jeffrey Energy Center during 2006 was approximately $1.37 per MMBtu, or $23.29 per ton.

La Cygne Generating Station: The two coal-fired units at La Cygne Generating Station (La Cygne) have an aggregate generating capacity of 1,422 MW, of which we own or lease a 50% share, or 711 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 2006, the average delivered cost of all coal burned at La Cygne unit 1 was approximately $1.10 per MMBtu, or $19.06 per ton. The average delivered cost of coal burned at La Cygne unit 2 was approximately $0.92 per MMBtu, or $15.58 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 774 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 for 2008 and 2009.

BNSF transports coal for these energy centers from Wyoming under a contract that expires in December 2008.

During 2006, the average delivered cost of all coal burned in the Lawrence units was approximately $1.15 per MMBtu, or $20.32 per ton. The average delivered cost of all coal burned in the Tecumseh units was approximately $1.15 per MMBtu, or $20.38 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 and the Spring Creek Energy Center. We can also use natural gas as a supplemental fuel in the coal-fired units at the Lawrence and Tecumseh Energy Centers. During 2006, we purchased 14.7 million MMBtu of natural gas on the spot market for a total cost of $95.7 million. Natural gas accounted for approximately 5% of our total MMBtu of fuel burned during 2006 and approximately 24% 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, 2007. 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. We meet all of the natural gas transportation requirements for the Spring Creek Energy Center through an interruptible natural gas transportation agreement with ONEOK Gas Transportation, LLC.

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 2006 oil was moderately more expensive than natural gas, and because of the additional handling cost of oil and additional environmental considerations associated with oil, we did not use oil as the primary fuel in these generating facilities in 2006. During 2006, we burned only 0.3 million MMBtu of oil at a total cost of $2.3 million. Oil accounted for less than 1% of our total MMBtu of fuel burned during 2006 and approximately 1% 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."

We also use oil to start some of our coal generating stations, as a primary fuel in the Hutchinson No. 4 combustion turbine and in our diesel generators. We purchase 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 our weighted average cost of fuel, including transportation costs.

	2006	2005	2004
Per MMBtu:			
Nuclear	$ 0.41	$ 0.42	$ 0.39
Coal	1.25	1.20	1.11
Natural gas	6.49	8.53	6.62
Oil	9.19	4.97	3.77
Per MWh Generation:			
Nuclear	$ 4.28	$ 4.34	$ 4.05
Coal	13.69	13.20	12.27
Natural gas/oil	66.91	68.19	52.98
All generating stations	14.94	15.36	12.64

Purchased Power

At times, we purchase electricity instead of generating it ourselves. Factors that cause us to make such purchases include planned and unscheduled outages at our generating plants, prices for wholesale energy, extreme weather conditions and other factors. Transmission constraints may limit our ability to bring purchased electricity into our control area, potentially requiring us to curtail or interrupt our customers as permitted by our tariffs and terms and conditions of service. Purchased power for the year ended December 31, 2006 comprised approximately 7% of our total operating expenses. The weighted average cost of purchased power was $54.90 per MWh in 2006, $59.05 per MWh in 2005 and $54.10 per MWh in 2004.

Energy Marketing Activities

We engage in both financial and physical trading with the goal of increasing profits, managing commodity price risk and enhancing 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. KGE owns a 47% interest in Wolf Creek, or 548 MW, which represents 9% of our total generating capacity. KCPL owns an equal 47% interest, with Kansas Electric Power Cooperative, Inc. (KEPCo) holding the remaining 6% interest. The co-owners pay operating costs equal to their percentage ownership in Wolf Creek.

In September 2006, Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, filed a request with the Nuclear Regulatory Commission (NRC) for a 20 year extension of Wolf Creek's operating license. Currently, the operating license will expire in 2025. We anticipate that the NRC may take up to two years before it rules on the request. The NRC may impose conditions as part of any approval. Based on the experience of other nuclear plant operators, we believe that the NRC will ultimately approve the request.

Fuel Supply

We have under contract 100% of the uranium and conversion services needed to operate Wolf Creek through March 2011. During 2006, we entered into contracts with suppliers which will cover a majority of Wolf Creek's uranium and conversion needs through 2017. Fabrication and enrichment requirements are under contract through 2024.

Because of a supply interruption at a major Canadian uranium mine, Wolf Creek will defer a small portion of the uranium fuel scheduled for delivery in 2007. This supply interruption may impact Wolf Creek's uranium deliveries in subsequent years as well. In anticipation of this possibility, Wolf Creek's owners authorized the purchase of additional uranium from an alternate supplier. We expect this purchase, combined with Wolf Creek's on-going operations strategies including its previous acquisition of strategic inventory, will minimize the impact of this fuel supply interruption. We cannot provide assurance that our mitigation efforts will eliminate the risk that supplies are not delivered as needed.

We have entered into all uranium, uranium conversion and uranium enrichment arrangements, as well as the fabrication agreements in the ordinary course of business. We believe Wolf Creek is not substantially dependent on these agreements. However, contraction and consolidation among suppliers of these commodities and services, increasing worldwide demand, past inventory draw-downs and flooding of a key mine of a leading industry supplier have introduced uncertainty as to the ability to replace, if necessary, volumes under these contracts in the event of a protracted supply disruption. We believe this uncertainty is not unique in the nuclear industry.

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 $4.1 million in 2006, $3.8 million in 2005 and $4.3 million in 2004 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 by the DOE 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 2025, the term of its existing operating license.

Wolf Creek disposes of all classes of its low-level radioactive waste at existing third-party repositories. Should disposal capability become unavailable, we believe Wolf Creek is able to store its low-level radioactive waste in an on-site facility. We believe that a temporary loss of low-level radioactive waste disposal capability would not affect Wolf Creek's continued operation.

The Low-Level Radioactive Waste Policy Amendments Act of 1985 mandated that the various states, individually or through interstate compacts, develop alternative low-level radioactive waste disposal facilities. The states of Kansas, Nebraska, Arkansas, Louisiana and Oklahoma formed the Central Interstate Low-Level Radioactive Waste Compact (Central States Compact), and the Central States Compact Commission, which is responsible for creating new disposal capability for the member states. The Central States Compact Commission selected Nebraska as the host state for the disposal facility.

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 34 days in 2006 for its fifteenth scheduled refueling and maintenance outage. During outages at the plant, we met our electric demand primarily with our other generating units and by purchasing power. As provided by the KCC, we defer and amortize evenly the incremental maintenance costs incurred for planned refueling outages over the unit's 18 month operating cycle. Wolf Creek is next scheduled to be taken off-line in the spring of 2008 for its sixteenth 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. Those concerns need not be related to Wolf Creek specifically, but could be due to concerns about nuclear power generally, or circumstances at other nuclear plants in which we have no ownership.

Nuclear Decommissioning

Nuclear decommissioning is a nuclear industry term for the permanent shutdown of a nuclear power plant and the removal of radioactive components in accordance with NRC requirements. The NRC will terminate a plant's license and release the property for unrestricted use when a company has reduced the residual radioactivity of a nuclear plant to a level mandated by the NRC. The NRC requires companies with nuclear plants to prepare formal financial plans to fund nuclear decommissioning. These plans are designed so that sufficient funds required for nuclear decommissioning will be accumulated prior to the expiration of the license of the related nuclear power plant. Wolf Creek files a nuclear decommissioning and dismantlement study with the KCC every three years.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the revised nuclear decommissioning study, the current-year funding and future funding. Phase two involves the review and approval by the KCC of a "funding schedule" by the owner of the nuclear facility detailing how it plans to fund the future-year dollar amount of its pro rata share of the plant.

In 2005, Wolf Creek filed an updated nuclear decommissioning site study with the KCC. Based on the site study of decommissioning costs, including the costs of decontamination, dismantling and site restoration, our share of such costs is 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 regulations, 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. We believe that the KCC approved funding level will also be sufficient to meet the NRC minimum financial assurance requirement. Our consolidated results of operations would be materially adversely affected if we are not allowed to recover in utility rates the full amount of the funding requirement.

We recovered in rates and deposited in an external trust fund approximately $3.9 million for nuclear decommissioning in 2006 and 2005 and $3.8 million in 2004. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $111.1 million as of December 31, 2006 and $100.8 million as of December 31, 2005.

Competition and Deregulation

The Federal Energy Regulatory Commission (FERC) requires owners of regulated transmission assets to allow third party wholesale providers of electricity nondiscriminatory access to their transmission systems to transport electric power to wholesale customers. FERC also requires us to provide transmission services to others under terms comparable to those we allow ourselves. In December 1999, FERC issued an order encouraging the formation of regional transmission organizations (RTOs). RTOs are designed to control the wholesale transmission services of the utilities in their regions, thereby facilitating competitive wholesale power markets.

Regional Transmission Organization

We are a member of the SPP, the RTO in our region. On September 19, 2006 the KCC approved an order allowing us to transfer functional control of our transmission system to the SPP under its membership agreement and applicable tariff. The SPP coordinates the operation of our transmission system within an interconnected transmission system that covers all or portions of eight states. The SPP collects revenues for the use of each transmission owner's transmission system. Transmission customers transmit throughout the entire SPP system power purchased and generated for sale or bought for resale in the wholesale market. Transmission capacity is sold on a first come/first served non-discriminatory basis. All transmission customers are charged rates applicable to the transmission system in the zone where energy is delivered, including transmission customers that may sell power inside our certificated service territory. We do not expect that our participation in the SPP will have a material effect on our operations, although we expect higher costs due to the administrative costs 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

The SPP is required by FERC to implement a real-time market to accommodate financial settlement of energy imbalances within the SPP region. An energy imbalance exists when a market participant's actual power inputs to or outputs from the transmission network differ from the level of inputs and outputs scheduled by the transmission user. The intent of a real-time market system is to permit more efficient balancing of energy production and consumption through the use of market protocols. The SPP implemented the real-time energy imbalance market on February 1, 2007. At this time we are unable to determine what impact this may have on our results of operations.

Regulation and Rates

Kansas law gives the KCC general regulatory authority over our rates, extensions and abandonments of service and facilities, the classification of accounts, the issuance of some securities and various other matters. We are also subject to the jurisdiction of FERC, which has authority over wholesale sales of electricity, the transmission of electric power and the issuance of some securities. We are subject to the jurisdiction of the NRC for nuclear plant operations and safety.

FERC Proceedings

Request for Change in Transmission Rates: On May 2, 2005, we filed applications with FERC that proposed a formula transmission rate providing for annual adjustments to our transmission costs. This is consistent with our proposals filed with the KCC on May 2, 2005 to charge retail customers separately for transmission service through a transmission delivery charge. The proposed FERC transmission rates became effective, subject to refund, December 1, 2005. On November 7, 2006 FERC issued an order reflecting a unanimous settlement reached by the parties to the proceeding. The settlement modified the rates we proposed and requires us to refund approximately $3.4 million, which includes the amount we collected in the interim rates since December 2005 and interest on that amount.

Environmental Matters

General

We are subject to various federal, state and local environmental laws and regulations. These laws and regulations relate primarily to discharges into the air, air quality, discharges of effluents into water, the use of water, and the handling 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. The 2005 KCC Order established the environmental cost recovery rider (ECRR), which will allow for the timely inclusion in rates of capital investments we make related directly 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 sulfur dioxide (SO_2), particulate matter and nitrogen oxides (NOx).

Certain Kansas Department of Health and Environment (KDHE) regulations applicable to our generating facilities prohibit the emission of SO_2 in excess of prescribed levels. In order to meet these standards, we use low-sulfur coal, 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 of this act. We have not had to make any material capital expenditures to meet Phase II SO_2 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 in the market in which such allowances are traded. In 2006, we had emissions allowances adequate to meet planned generation and we expect to have enough in 2007. In the future we may need to purchase additional allowances. We expect to recover the cost of emission allowances through the RECA. The pricing of emissions allowances is unpredictable and may change over time.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule. The rule caps permanently, and seeks to reduce, the amount of mercury that may be emitted from coal-fired power plants. The Clean Air Mercury Rule requires reductions of mercury in two phases, the first starting in 2010. To comply with this rule we will need to install and maintain additional equipment at our coal-fired units. Several different environmental groups and states are challenging this rule in court, which could potentially delay its implementation. 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, we will need to have installed and certified by January 1, 2009, continuous emissions mercury monitoring systems on each coal-fired unit. We do not know what the costs to comply with the Clean Air Mercury Rule will be, but we believe they could be material.

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

- the EPA's national ambient air quality standards for particulate matter and ozone;
- the EPA's regional haze rules, designed to reduce SO_2, NOx 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, NOx, SO_2 and mercury, and the "Clear Skies" legislation proposed by the President, which would cap emissions of NOx, SO_2 and mercury.

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

Environmental Projects

KCPL began installing additional equipment related to emissions controls at La Cygne in 2005. We currently expect our share of these capital costs through the scheduled completion in 2009 to be approximately $232.5 million. Additionally, we have identified the potential for up to $512.4 million of capital expenditures for environmental projects at our other power plants during the next seven to ten years. Our estimated costs of these projects have increased since we first announced these programs. These amounts could increase further depending on the resolution of the EPA New Source Review described below and other factors. In addition to the capital investment, when we install such equipment, we will also incur significant annual expense to operate and maintain the equipment and the operation of the equipment reduces net production from our plants. The ECRR allows for the timely inclusion in rates of capital expenditures tied directly to environmental improvements required by the Clean Air Act. However, increased operating and maintenance costs, other than expenses related to production-related consumables, such as limestone, can be recovered only 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 controls 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. In addition, the availability of equipment and contractors can affect the timing and ultimate cost of equipment installation. We expect to recover such costs through the rates we charge our customers.

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 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. 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. We are not able to estimate the possible loss or range of loss at this time.

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. We have sole responsibility for remediation with respect to three sites.

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

SEASONALITY

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

EMPLOYEES

As of February 15, 2007, we had 2,223 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 1,279 employees as of February 15, 2007.

ACCESS TO COMPANY INFORMATION

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K are available free of charge either through our Internet website at www.westarenergy.com or by responding to requests addressed to our investor relations department. These reports are available as soon as reasonably practicable after such material is electronically filed with, or furnished to, the Securities and Exchange Commission (SEC). The information contained on our Internet website is not part of this document.

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During the Past Five Years
James S. Haines, Jr.	60	Director and Chief Executive Officer (since March 2006)	**Westar Energy, Inc.** Director, Chief Executive Officer and President (December 2002 to March 2006) **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)
William B. Moore	54	President and Chief Operating Officer (since March 2006)	**Westar Energy, Inc.** Executive Vice President and Chief Operating Officer (December 2002 to March 2006) **Saber Partners, LLC** Senior Managing Director and Senior Advisor (October 2000 to December 2002)
Mark A. Ruelle	45	Executive Vice President and Chief Financial Officer (since January 2003)	**Sierra Pacific Resources, Inc.** President, Nevada Power Company (June 2001 to May 2002)
Douglas R. Sterbenz	43	Executive Vice President, Generation and Marketing (since March 2006)	**Westar Energy, Inc.** Senior Vice President, Generation and Marketing (October 2001 to March 2006)
Bruce A. Akin	42	Vice President, Administrative Services (since December 2001)	
Larry D. Irick	50	Vice President, General Counsel and Corporate Secretary (since February 2003)	**Westar Energy, Inc.** Vice President and Corporate Secretary (December 2001 to February 2003)
James J. Ludwig	48	Vice President, Regulatory and Public Affairs (since March 2006)	**Westar Energy, Inc.** Vice President, Public Affairs (January 2003 to March 2006)
Lee Wages	58	Vice President, Controller (since December 2001)	

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

ITEM 1A. RISK FACTORS

Like other companies in our industry, our consolidated financial results will be impacted by weather, the economy of our service territory and the energy use of our customers. The value of our common stock and our creditworthiness will be affected by national and international macroeconomic trends, general market conditions and the expectations of the investment community, all of which are largely beyond our control. In addition, the following statements highlight risk factors that may affect our consolidated financial 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 rates that we charge customers for retail 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 and a return on 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 that left our base rates virtually unchanged but approved various changes to our rate structure that allow some adjustment to our prices. The KCC approved the RECA, which allows us to recover cost of fuel for generation and purchased power expense (less margins earned on wholesale sales). It also authorized us to implement the ECRR, which allows us to change our rates to reflect the impact of capital expenditures made to upgrade our equipment to environmental standards required by the Clean Air Act.

Our Costs May Not be Fully Recovered in Retail Rates

Except to the extent the KCC permits us to modify our prices by using specific adjustments and riders such as the RECA and the ECRR, once established by the KCC, our rates generally remain fixed until changed in a subsequent rate review. We may apply to change our rates or intervening parties may request that 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 maintenance programs in place, generating plants are subject to unplanned outages because of equipment failure. In these events, we must either produce replacement power from our other, usually less efficient, units or purchase power from others at unpredictable and potentially higher cost in order to meet our sales obligations. In addition, equipment failure can limit our ability to make opportunistic sales to wholesale customers.

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

Coal deliveries from the PRB region of Wyoming, the primary source for our coal, can be interrupted or can be slowed due to rail traffic congestion, equipment or track failure, or due to loading problems at the mines. This may require that we implement coal conservation efforts and/or take other compensating measures. We experienced these problems and conserved coal to varying degrees in 2005 and 2006. These measures may include, but are not limited to, reducing coal consumption by revising normal dispatch of generation units, purchasing power or using more expensive power to serve customers and decreasing or, if necessary, eliminating opportunistic wholesale sales. In addition, decisions or mistakes by other utilities may adversely affect our ability to use transmission lines to deliver or import power, thus subjecting us to unexpected expenses or to the cost and uncertainty of public policy initiatives. These factors, along with the prices and price volatility of fuel and wholesale electricity are largely beyond our control. Costs that are not recovered through the RECA could have a material adverse effect on our consolidated 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.

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 in our rates the costs that we incur to comply with environmental regulations, we can provide no assurance that we will be able to fully and timely recover such costs. 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 Statement of Financial Accounting Standard (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," to our regulated business. As of December 31, 2006, we had recorded $476.0 million of regulatory assets, net of regulatory liabilities. In the event we determined that we could no longer apply the principles of SFAS No. 71, either as: (i) a result of the establishment of retail competition in our service territory; (ii) a change in the regulatory approach for setting rates from cost-based ratemaking to another form of ratemaking; or (iii) other regulatory actions that restrict cost recovery to a level insufficient to recover costs, we would be required to record a charge against income in the amount of the remaining unamortized net regulatory assets. Such an action would materially reduce our shareholders' equity. We periodically review these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Based upon current evaluation of the various factors that are expected to impact future cost recovery, we believe that our regulatory assets are probable of recovery.

We Face Financial Risks Associated With Wolf Creek

Risks of substantial liability arise from the ownership and operation of nuclear facilities, including, among others, structural problems at a nuclear facility, the storage, handling and disposal of radioactive materials, limitations on the amounts and types of insurance coverage commercially available, uncertainties with respect to the cost and technological aspects of nuclear decommissioning at the end of their useful lives and costs or measures associated with public safety. In the event of an extended or unscheduled outage at Wolf Creek, we would be required to generate power from more costly generating units, purchase power in the open market to replace the power normally produced at Wolf Creek and we would have less power available for sale into the wholesale markets. If we were not permitted by the KCC to recover these costs, such events would likely have an adverse impact on our consolidated financial condition.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

				Unit Capacity (MW) By Owner		
Name/Location	Unit No.	Year Installed	Principal Fuel	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	—	151.0	151.0
	2	1967	Gas – Oil	—	374.0	374.0
Combustion Turbines	1	2000	Gas	74.0	—	74.0
	2	2000	Gas	72.0	—	72.0
	3	2001	Gas	146.0	—	146.0
Diesel Generator	1	1969	Diesel	—	3.0	3.0
Hutchinson Energy Center:						
Hutchinson, Kansas						
Steam Turbine	4	1965	Gas – Oil	166.0	—	166.0
Combustion Turbines	1	1974	Gas	51.0	—	51.0
	2	1974	Gas	51.0	—	51.0
	3	1974	Gas	56.0	—	56.0
	4	1975	Diesel	75.0	—	75.0
Diesel Generator	1	1983	Diesel	3.0	—	3.0
Jeffrey Energy Center (84%):						
St. Marys, Kansas						
Steam Turbines	1 [(a)]	1978	Coal	467.0	146.0	613.0
	2 [(a)]	1980	Coal	467.0	146.0	613.0
	3 [(a)]	1983	Coal	467.0	146.0	613.0
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	—	370.0	370.0
	2 [(b)]	1977	Coal	—	341.0	341.0
Lawrence Energy Center:						
Lawrence, Kansas						
Steam Turbines	3	1954	Coal	49.0	—	49.0
	4	1960	Coal	110.0	—	110.0
	5	1971	Coal	373.0	—	373.0
Murray Gill Energy Center:						
Wichita, Kansas						
Steam Turbines	1	1952	Gas	—	39.0	39.0
	2	1954	Gas – Oil	—	63.0	63.0
	3	1956	Gas – Oil	—	95.0	95.0
	4	1959	Gas – Oil	—	99.0	99.0
Neosho Energy Center:						
Parsons, Kansas						
Steam Turbine	3	1954	Gas – Oil	—	66.0	66.0
Spring Creek Energy Center						
Edmond, Oklahoma						
Combustion Turbines	1	2001 [(c)]	Gas	75.0	—	75.0
	2	2001	Gas	75.0	—	75.0
	3	2001	Gas	75.0	—	75.0
	4	2001	Gas	75.0	—	75.0
State Line (40%):						
Joplin, Missouri						
Combined Cycle	2-1 [(a)]	2001	Gas	65.0	—	65.0
	2-2 [(a)]	2001	Gas	65.0	—	65.0
	2-3 [(a)]	2001	Gas	74.0	—	74.0

Name/Location	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) By Owner Westar Energy	KGE	Total Company
Tecumseh Energy Center:						
Tecumseh, Kansas						
Steam Turbines	7	1957	Coal	74.0	—	74.0
	8	1962	Coal	130.0	—	130.0
Combustion Turbines	1	1972	Gas	19.0	—	19.0
	2	1972	Gas	19.0	—	19.0
Wolf Creek Generating Station (47%):						
Burlington, Kansas						
Nuclear	1 [a]	1985	Uranium	—	548.0	548.0
Total				3,446.0	2,587.2	6,033.2

[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.*

[c] *We acquired Spring Creek Energy Center in 2006.*

We own approximately 6,100 miles of transmission lines, approximately 23,700 miles of overhead distribution lines and approximately 3,800 miles of underground distribution lines.

Substantially all of our utility properties are encumbered by first priority mortgages pursuant to which bonds have been issued and are outstanding.

ITEM 3. LEGAL PROCEEDINGS

Information on other legal proceedings is set forth in Notes 3, 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 — Department of Labor Investigation," 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

None.

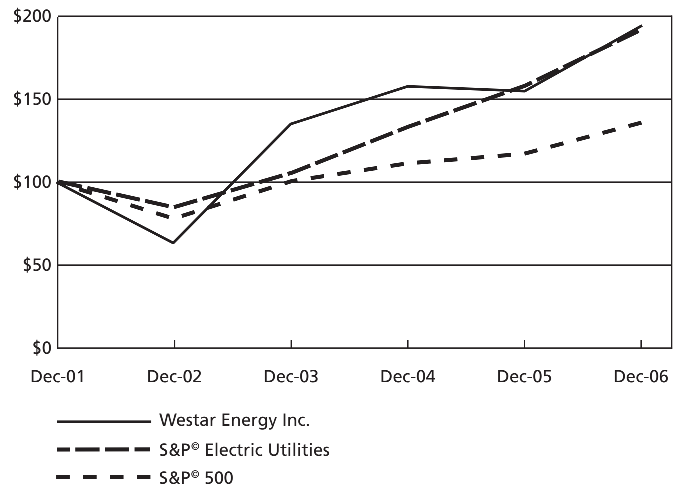
PART II

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

STOCK PERFORMANCE GRAPH

The following performance graph compares the performance of our common stock during the period that began on December 31, 2001 and ended on December 31, 2006 to the Standard & Poor's 500 Index and the Standard & Poor's Electric Utility Index. The graph assumes a $100 investment in our common stock and in each of the indices at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.

CUMULATIVE TOTAL RETURN
Based upon an initial investment of $100 on December 31, 2001 with dividends reinvested



	Dec-2001	Dec-2002	Dec-2003	Dec-2004	Dec-2005	Dec-2006
Westar Energy Inc.	$100	$63	$135	$158	$155	$195
S&P 500	$100	$78	$100	$111	$117	$135
S&P Electric Utilities	$100	$85	$105	$133	$157	$193

STOCK TRADING

Our common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 15, 2007, there were 26,449 common shareholders of record. For information regarding quarterly common stock price ranges for 2006 and 2005, see Note 23 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 and preferred stock have historically been paid on or about the first business day of January, April, July and October to shareholders of record as of or about the ninth day of the preceding month. Our board of directors reviews our common stock dividend policy from time to time. Among the factors the board of directors considers in determining our dividend policy are earnings, cash flows, capitalization ratios, regulation, competition and financial loan covenants. During 2006 our board of directors declared four quarterly dividends, each at $0.25 per share, reflecting an annual dividend of $1.00 per share. On February 21, 2007, our board of directors declared a quarterly dividend of $0.27 per share on our common stock payable to shareholders on April 2, 2007. The indicated annual dividend rate is $1.08 per share.

Our articles of incorporation restrict the payment of dividends or the making of other distributions on our common stock while any preferred shares remain outstanding unless we meet certain capitalization ratios and other conditions. We were not limited by any such restrictions during 2006. 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.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31,	2006	2005	2004	2003	2002[b]
			(In Thousands)		
Income Statement Data:					
Sales	$ 1,605,743	$ 1,583,278	$ 1,464,489	$ 1,461,143	$ 1,423,151
Income from continuing operations before accounting change[a]	165,309	134,868	100,080	162,915	88,816
Earnings (loss) available for common stock	164,339	134,640	177,900	84,042	(793,400)

As of December 31,	2006	2005	2004	2003	2002
			(In Thousands)		
Balance Sheet Data:					
Total assets	$ 5,455,175	$ 5,210,069	$ 5,001,144	$ 5,672,520	$ 6,756,666
Long-term obligations and mandatorily redeemable preferred stock[c]	1,580,108	1,681,301	1,724,967	2,259,880	3,222,556

Year Ended December 31,	2006	2005	2004	2003	2002[b]
Common Stock Data:					
Basic earnings per share available for common stock from continuing operations before accounting change	$ 1.88	$ 1.54	$ 1.19	$ 2.24	$ 1.23
Basic earnings (loss) per share available for common stock	$ 1.88	$ 1.55	$ 2.14	$ 1.16	$ (11.06)
Dividends declared per share	$ 1.00	$ 0.92	$ 0.80	$ 0.76	$ 1.20
Book value per share	$ 17.61	$ 16.31	$ 16.13	$ 13.98	$ 13.41
Average equivalent common shares outstanding (in thousands)[d]	87,510	86,855	82,941	72,429	71,732

[a] *In 2002, we recognized a cumulative effect of accounting change of $623.7 million due to recording an impairment charge for goodwill.*

[b] *Our losses in 2002 were attributable primarily to impairment charges 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.*

[d] *In 2004, we issued and sold approximately 12.5 million shares of common stock realizing net proceeds of $245.1 million.*

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

INTRODUCTION

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

In Management's Discussion and Analysis, we discuss our general financial condition, significant changes that occurred during 2006, and our operating results for the years ended December 31, 2006, 2005 and 2004. As you read Management's Discussion and Analysis, please refer to our consolidated financial statements and the accompanying notes, which contain our operating results.

SUMMARY OF SIGNIFICANT ITEMS

Overview

Several significant items have impacted or may impact us and our operations since January 1, 2006:

- Portions of the 2005 KCC Order were challenged and ultimately reversed by the KCC. See "— Changes in Rates" below for additional information;
- We implemented the RECA which allows us to adjust our prices to correspond with changes in the costs we incur for fuel and purchased power;
- We purchased a 300 MW peaking power plant, announced plans to build a 600 MW peaking power plant and announced plans to expand our electric transmission network. See "— Increased Capacity and Future Plans" below for additional information;
- We plan to install emissions control equipment at Jeffrey Energy Center and some of our other coal plants. Due to increasing prices of labor and materials, we increased the estimated costs of installing this equipment at our power plants. For additional information, see "— Liquidity and Capital Resources — Future Cash Requirements";
- The convictions of David C. Wittig and Douglas T. Lake were overturned. See "— Convictions of David C. Wittig and Douglas T. Lake Overturned" below for additional information;
- We received $18.9 million in proceeds from corporate-owned life insurance in 2006 and $9.5 million in 2005; and
- We took measures, including the acquisition of additional rail cars and the conservation of coal, that when coupled with changes at the mines and with the railroads, resulted in improved coal deliveries. See "— Coal Inventory and Delivery" below for additional information.

Changes in Rates

In accordance with a 2003 KCC Order, on May 2, 2005, we filed applications with the KCC for it to review our retail electric rates. The 2005 KCC Order authorized changes in our rates, which we began billing in the first quarter of 2006, and approved various other changes to our rate structures. In April 2006, interveners filed appeals with the Kansas Court of Appeals challenging various aspects of the 2005 KCC Order. On July 7, 2006, the Kansas Court of Appeals reversed and remanded for further consideration by the KCC three elements of the 2005 KCC Order. The balance of the 2005 KCC Order was upheld.

On February 8, 2007, the KCC issued an order in response to the Kansas Court of Appeals' decision regarding the 2005 KCC Order. In its February 8, 2007 Order the KCC: (i) confirmed its original decision regarding its treatment of the La Cygne unit 2 sale-leaseback transaction; (ii) in lieu of a transmission delivery charge, ruled that it intends to permit us to recover our transmission related costs in a manner similar to how we recover our other costs; and (iii) reversed itself with regard to the inclusion in depreciation rates of a component for terminal net salvage. The February 8, 2007 KCC Order requires us to refund to our customers the amount we have collected related to terminal net salvage. We have recorded a regulatory liability at December 31, 2006 in the amount of $16.4 million related to this item.

Increased Capacity and Future Plans

On October 31, 2006, we purchased a 300 MW electric generation facility and related assets from ONEOK Energy Services Company, L.P. (OESC) for $53.0 million. As part of this transaction, we entered into an agreement to provide OESC with 75 MW of capacity through 2015.

In August 2006, we announced plans to build a new natural gas-fired combustion turbine peaking power plant near Emporia in Lyon County, Kansas. We expect the new plant, which we have named the Emporia Energy Center, to have an initial generating capacity of up to 300 MW, with additional capacity to be added in a second phase, bringing the total capacity to approximately 600 MW. We expect the total investment in the plant to be about $318 million. We plan to begin construction on the new plant in the spring of 2007. The initial phase of the plant is scheduled to begin operation in the summer of 2008.

In September 2006, we announced plans to build a transmission line from our Gordon Evans Energy Center northwest of Wichita, Kansas, to a new substation near Hutchison, Kansas, then onto our Summit substation near Salina, Kansas, a distance totaling approximately 86 miles. In January 2007, we filed an application with the KCC to request permission to build the line. Kansas law requires the KCC to issue an order within 120 days of our filing regarding our application. If the KCC issues a permit for us to proceed, we expect to complete construction in 2009. Our preliminary cost estimate for the project is $80 million to $100 million. This estimate could change materially as engineering and construction proceed. In addition to this line, we plan additional expansions to our electric transmission network in Kansas. These include a new line from our Rose Hill substation near Wichita to the Kansas-Oklahoma border, where we expect to interconnect with new facilities built by an Oklahoma-based utility, and a new line from our Jeffrey Energy Center to an existing substation about 15 miles south of Topeka, Kansas.

Convictions of David C. Wittig and Douglas T. Lake Overturned

On September 12, 2005, David C. Wittig, our former chairman of the board, president and chief executive officer, and Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, were convicted on various criminal charges by a jury in a trial held in U.S. District court in Kansas. The jury 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 awarded us certain of the property forfeited by Mr. Wittig and Mr. Lake. On January 5, 2007, the U.S. Tenth Circuit Court of Appeals overturned these convictions and forfeiture orders. At December 31, 2006, we had accrued liabilities totaling approximately $74.8 million for compensation not yet paid to Mr. Wittig and Mr. Lake under various plans, and we had also accrued approximately $9.9 million for legal fees and expenses incurred by Mr. Wittig and Mr. Lake in the defense of these charges and related appeals. We believe Mr. Wittig and Mr. Lake are not entitled to this compensation. This dispute, and claims Mr. Wittig and Mr. Lake have made against us, are the subject of an arbitration that has been stayed pending the resolution of the criminal proceedings. We also believe the amounts sought by Mr. Wittig and Mr. Lake for legal fees and expenses are unreasonable. These disputes are also the subject of litigation. We are unable to predict whether the government will retry the criminal charges against Mr. Wittig and Mr. Lake or the outcome of these matters, including their ultimate impact on our results of operations. For additional information, see Note 18 of the Notes to Consolidated Financial Statements, "Potential Liabilities to David C. Wittig and Douglas T. Lake."

Coal Inventory and Delivery

Coal deliveries from the Powder River Basin region of Wyoming to our coal-fired generating stations improved in 2006; however, they continue to be slower than historical averages due primarily to issues at the coal mines and with the rail delivery system. During 2005 and continuing in 2006, we implemented compensating measures based on delivery cycle times, our assumptions about future delivery cycle times, fuel usage and planned inventory levels. We may continue to use these measures as conditions warrant. The compensating measures include, but are not limited to: reducing coal consumption during certain periods, revising normal operational dispatch of our generating units, purchasing power from others, reducing wholesale sales and leasing additional rail cars. The effects of additional purchased power expense and the reduction in sales due to slower coal deliveries have been partially offset by higher market-based wholesale sales prices.

CRITICAL ACCOUNTING ESTIMATES

Our discussion and analysis of financial condition and results of operations are based on our consolidated financial statements, which have been prepared in conformity with generally accepted accounting principles (GAAP). Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies," contains a summary of our significant accounting policies, many of which require the use of estimates and assumptions by management. The policies highlighted below have an impact on our reported results that may be material due to the levels of judgment and subjectivity necessary to account for uncertain matters or their susceptibility to change.

Regulatory Accounting

We currently apply accounting standards for our regulated utility operations that recognize the economic effects of rate regulation in accordance with SFAS No. 71. Accordingly, we have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in utility rates. Regulatory liabilities represent probable future reductions in revenue or refunds to customers.

The deferral of costs as regulatory assets is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific orders from the KCC, regulatory precedent and the current regulatory environment. To the extent recovery of costs is no longer deemed to be probable, we would record a charge against income in the amount of the related regulatory assets.

Pension and Post-retirement Benefit Plans Actuarial Assumptions

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

In accounting for our retirement plans and other post-retirement benefits, we make assumptions regarding the valuation of benefit obligations and the performance of plan assets. The reported costs of our pension plans are impacted by estimates regarding earnings on plan assets, contributions to the plan, discount rates used to determine our projected benefit obligation and pension costs and employee demographics including age, compensation levels and employment periods. A change in any of these assumptions could have a significant impact on future costs, which may be reflected as an increase or decrease in net income in the current and future periods, or on the amount of related liabilities reflected on our consolidated balance sheets or may also require cash contributions.

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

Actuarial Assumption	Change in Assumption	Annual Change in Projected Benefit Obligation	Annual Change in Pension Liability/ Asset	Annual Change in Projected Pension Expense
		(In Thousands)		
Discount rate	0.5% decrease	$46,609	$46,609	$4,697
	0.5% increase	(43,650)	(43,650)	(4,616)
Salary scale	0.5% decrease	(11,536)	(11,536)	(1,153)
	0.5% increase	11,735	11,735	1,165
Rate of return on plan assets	0.5% decrease	—	—	2,455
	0.5% increase	—	—	(2,455)

We recorded pension expense of approximately $21.4 million in 2006, $12.2 million in 2005 and $5.1 million in 2004. These amounts reflect the pension expense of Westar Energy and our 47% responsibility for the pension expense of Wolf Creek. Pension expense increases are due primarily to the amortization of investment losses from prior years that are recognized on a rolling four-year average basis and changes in assumptions including lower discount rates, lower returns on assets, increases in salaries and updated mortality tables. Pension expense for 2007 is expected to be approximately $20.1 million.

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

Actuarial Assumption	Change in Assumption	Annual Change in Projected Benefit Obligation	Annual Change in Post-retirement Liability/ Asset	Annual Change in Projected Post-retirement Expense
		(In Thousands)		
Discount rate	0.5% decrease	$7,403	$7,403	$449
	0.5% increase	(7,013)	(7,013)	(454)
Rate of return on plan assets	0.5% decrease	—	—	222
	0.5% increase	—	—	(219)

Revenue Recognition — Energy Sales

We record revenue as electricity is delivered. Amounts delivered to individual customers are determined through the systematic monthly readings of customer meters. At the end of each month, the electric usage from the last meter reading is estimated and corresponding unbilled revenue is recorded.

The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $38.4 million as of December 31, 2006 and $42.1 million as of December 31, 2005.

We account for energy marketing derivative contracts under the mark-to-market method of accounting. Under this method, we recognize changes in the value of contracts in our portfolio as gains or losses in the period of change. With the exception of contracts for fuel that we purchase to produce energy in our power plants, we include the net mark-to-market change in sales on our consolidated statements of income. We record the resulting unrealized gains and losses as energy marketing long-term or short-term assets and liabilities on our consolidated balance sheets as appropriate. We use quoted market prices to value our energy marketing derivative contracts when such data is available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. Prices used to value these transactions reflect our best estimate of fair value 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 the fair value of energy marketing and fuel contracts that were outstanding as of December 31, 2006, their sources and maturity periods.

	Fair Value of Contracts
	(In Thousands)
Net fair value of contracts outstanding as of December 31, 2005	$117,929
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	(44,239)
Changes in fair value of contracts outstanding at the beginning and end of the period	(61,536)
Fair value of new contracts entered into during the period	8,471
Fair value of contracts outstanding as of December 31, 2006[(a)]	$ 20,625

[(a)] *Approximately $12.8 million of the fair value of fuel supply contracts is recognized as a regulatory liability.*

The sources of the fair values of the financial instruments related to these contracts as of December 31, 2006 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
		(In Thousands)	
Prices provided by other external sources (swaps and forwards)	$13,091	$ 8,994	$ 4,097
Prices based on option pricing models (options and other)[(a)]	7,534	992	6,542
Total fair value of contracts outstanding	$20,625	$ 9,986	$10,639

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

Income Taxes

We use the asset and liability method of accounting for income taxes as required by SFAS No. 109, "Accounting for Income Taxes." Under the asset and liability method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over the lives of the related properties.

We record deferred tax assets for capital losses, operating losses and tax credit carryforwards. However, when we believe we do not or will not have sufficient future capital gain income or taxable income to realize the benefit of the capital loss, operating loss or tax credit carryforwards, we reduce the deferred tax assets by a valuation allowance. We recognize a valuation allowance if we determine, based on available evidence that it is unlikely that we will realize some portion or all of the deferred tax asset. We report the effect of a change in the valuation allowance in the current period tax expense.

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 earnings per share. We have various classifications of sales, defined as follows:

Retail: Sales of energy made to residential, commercial and industrial customers.

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

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

Market-based wholesale: Sales of energy to wholesale customers, the rates for which are generally based on prevailing market prices as allowed by our FERC approved market-based tariff, or where not permitted, pricing is based on incremental cost plus a permitted margin. This category also includes changes in valuations of contracts that have yet to settle.

Energy marketing: Includes: (i) transactions based on market prices with volumes not related to the production of our generating assets or the demand of our retail customers; (ii) financially settled products and physical transactions sourced outside our control area; and (iii) 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, including those based on a tariff with the SPP.

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

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

2006 Compared to 2005

Below we discuss our operating results for the year ended December 31, 2006 compared to the results for the year ended December 31, 2005. Changes in results of operations are as follows.

Year Ended December 31,	2006	2005	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 486,107	$ 458,806	$ 27,301	6.0
Commercial	438,342	404,590	33,752	8.3
Industrial	266,922	242,383	24,539	10.1
Other retail	(32,098)	376	(32,474)	[b]
Total Retail Sales	1,159,273	1,106,155	53,118	4.8
Tariff-based wholesale	195,428	185,598	9,830	5.3
Market-based wholesale	101,217	145,628	(44,411)	(30.5)
Energy marketing	40,113	47,089	(6,976)	(14.8)
Transmission[a]	83,764	76,591	7,173	9.4
Other	25,948	22,217	3,731	16.8
Total Sales	1,605,743	1,583,278	22,465	1.4
OPERATING EXPENSES:				
Fuel and purchased power	483,959	528,229	(44,270)	(8.4)
Operating and maintenance	463,785	437,741	26,044	5.9
Depreciation and amortization	180,228	150,520	29,708	19.7
Selling, general and administrative	171,001	166,060	4,941	3.0
Total Operating Expenses	1,298,973	1,282,550	16,423	1.3
INCOME FROM OPERATIONS	306,770	300,728	6,042	2.0
OTHER INCOME (EXPENSE):				
Investment earnings	9,212	11,365	(2,153)	(18.9)
Other income	18,000	9,948	8,052	80.9
Other expense	(13,711)	(17,580)	3,869	22.0
Total Other Income	13,501	3,733	9,768	261.7
Interest expense	98,650	109,080	(10,430)	(9.6)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	221,621	195,381	26,240	13.4
Income tax expense	56,312	60,513	(4,201)	(6.9)
INCOME FROM CONTINUING OPERATIONS	165,309	134,868	30,441	22.6
Results of discontinued operations, net of tax	—	742	(742)	(100.0)
NET INCOME	165,309	135,610	29,699	21.9
Preferred dividends	970	970	—	—
EARNINGS AVAILABLE FOR COMMON STOCK	$ 164,339	$ 134,640	$ 29,699	22.1
BASIC EARNINGS PER SHARE	$ 1.88	$ 1.55	$ 0.33	21.3

[a] ***Transmission:*** *Includes an SPP network transmission tariff. In 2006, our SPP network transmission costs were approximately $76.0 million. This amount, less approximately $10.1 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2005, our SPP network transmission costs were approximately $66.2 million with an administration cost of $5.5 million retained by the SPP.*

[b] *Change greater than 1000%*

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

Year Ended December 31,	2006	2005	Change	% Change
	(Thousands of MWh)			
Residential	6,456	6,384	72	1.1
Commercial	7,185	7,151	34	0.5
Industrial	5,824	5,581	243	4.4
Other retail	93	101	(8)	(7.9)
Total Retail	19,558	19,217	341	1.8
Tariff-based wholesale	5,505	5,490	15	0.3
Market-based wholesale	1,913	2,950	(1,037)	(35.2)
Total	26,976	27,657	(681)	(2.5)

The increase in retail sales reflects the change in rates, including the effect of implementing the RECA, and warmer weather. When measured by cooling degree days, the weather during 2006 was 2% warmer than during 2005 and approximately 16% warmer than the 20-year average. The increase in industrial sales was due primarily to additional oil refinery load. The change in other retail sales reflects the recognition in 2006 of revenue subject to refund, of which: (i) $19.9 million is due to the difference between estimated fuel and purchased power costs billed to our customers and actual fuel and purchased power costs incurred for our Westar Energy customers; (ii) $3.3 million is due to amounts associated with a transmission delivery charge approved by the KCC in its 2005 Order; (iii) $4.0 million collected for property taxes in excess of our actual property taxes obligations; and (iv) $16.4 million related to amounts we collected in rates related to terminal net salvage that the KCC's February 8, 2007 Order requires us to refund. The revenue subject to refund was partially offset by our having stopped accruing for rebates to customers in December 2005.

We made tariff-based sales in 2006 at an average price that was about 5% higher than the price of these sales in 2005. We attribute about $1.3 million, or 14%, of the increase in tariff-based wholesale sales to higher prices reflecting an adjustment for our fuel costs as permitted in FERC tariffs.

Our market-based wholesale sales and sales volumes decreased in 2006 due primarily to our having conserved coal inventories, but the average price per MWh that we received for these sales in 2006 was about 7% higher than in 2005.

The change in fuel and purchased power expense is the result of changing volumes produced and purchased, prevailing market prices and contract provisions that allow for price changes. We burned about 4% less fuel in our generating plants in 2006, due primarily to our having conserved coal inventories. We also used less expensive generation. In addition, during 2006 we deferred as a regulatory asset $6.9 million for the difference between the estimated fuel and purchased power costs that we billed our KGE customers and our higher actual fuel and purchased power costs that we are allowed to collect under the terms of the RECA. As a result, our fuel expense was $45.5 million lower in 2006 than in 2005. We also experienced a $1.2 million increase in our purchased power expense due primarily to our having purchased 9% greater volumes than in 2005.

We experienced an increase in our operating and maintenance expense due primarily to four factors: (i) the amortization of $10.7 million of previously deferred storm restoration expenses as authorized by the 2005 KCC Order; (ii) a $9.9 million increase in SPP network transmission costs; (iii) a $4.7 million increase in taxes other than income taxes due primarily to higher property taxes; and (iv) an increase in maintenance expenses for outages at La Cygne and the Gordon Evans Energy Center. These higher expenses were partially offset by a $5.4 million reduction in the lease expense related to La Cygne unit 2. Operating and maintenance expense in 2005 included a $10.4 million loss as a result of the decrease in the present value of previously disallowed plant costs associated with the original construction of Wolf Creek due to the extension of the recovery period.

We experienced an increase in our depreciation and amortization expense of $29.7 million. This increase was due primarily to the reduction of depreciation expense of $20.1 million in 2005 due to the establishment of a regulatory asset for the differences between the depreciation rates we used for financial reporting purposes and the depreciation rates authorized by the KCC for the period of August 2001 to March 2002. Provisions of the 2005 KCC Order allowed us to record this regulatory asset.

Selling, general and administrative expenses increased due primarily to increased employee pension and benefit costs. Partially offsetting these increases were lower legal fees associated with matters having to deal with former management and a decline in insurance costs.

Other income increased due primarily to corporate-owned life insurance. We received $16.4 million in income from corporate-owned life insurance in 2006 compared to $7.2 million in 2005. Associated with our having terminated an accounts receivable sales facility we experienced a $3.9 million decrease in other expense.

Interest expense decreased due primarily to a $16.7 million reduction in interest expense on long-term debt due primarily to a lower long-term debt balance and lower interest rates resulting from the refinancing activities discussed in detail in "— Liquidity and Capital Resources — Debt Financings." This decline was partially offset by an increase of $6.3 million in interest expense on short-term debt due to increased borrowings under our revolving credit facility.

The decrease in income tax expense is due primarily to the utilization of previously unrecognized capital loss carryforwards to offset realized capital gains and increases in non-taxable income from corporate-owned life insurance.

2005 Compared to 2004

Below we discuss our operating results for the year ended December 31, 2005 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.

Year Ended December 31,	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.

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 pursuant to the 2005 KCC Order.

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. Increased employee pension and benefit costs partially offset the decrease.

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.

FINANCIAL CONDITION

A number of factors affected amounts recorded on our balance sheet as of December 31, 2006 compared to December 31, 2005.

Total restricted cash decreased due primarily to the return of $26.0 million of collateral we had previously been required to post related to a capacity and transmission agreement. In May 2006, Moody's Investors Service upgraded its credit ratings for our debt securities, which met conditions in the agreement that allowed the funds to be released.

Our accounts receivable balance increased by $55.1 million due primarily to our having terminated an accounts receivable sales facility during the year. This is discussed in Note 4 of the Notes to Consolidated Financial Statements, "Accounts Receivable Sales Program."

Inventories and supplies increased $46.1 million due primarily to increases in fuel stock. As a result of our coal conservation efforts and other measures we implemented to improve coal deliveries, we were able to build our coal inventories.

Due primarily to lower market valuations on our coal supply contract for Lawrence and Tecumseh Energy Centers the fair market value of our net energy marketing contracts decreased $97.3 million to $20.6 million as of December 31, 2006 compared to $117.9 million as of December 31, 2005.

Regulatory assets, net of regulatory liabilities, increased to $476.0 million at December 31, 2006, from $275.0 million at December 31, 2005. Total regulatory assets increased $172.0 million due primarily to the $186.3 million increase in deferred employee benefit costs for pension and post-retirement benefit obligations recognized pursuant to SFAS No. 158. Total regulatory liabilities decreased $29.0 million due primarily to the change in the market value of the coal supply contract for our Lawrence and Tecumseh Energy Centers as noted in the discussion of inventories above. As of December 31, 2006, we recorded a regulatory liability of $12.8 million compared with $117.7 million as of December 31, 2005 to recognize the mark-to-market value of our coal supply contracts. This decline was partially offset by a $32.7 million increase in the nuclear decommissioning regulatory liability as discussed in Note 15 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations," $19.9 million of revenue subject to refund for amounts collected from the RECA and $16.4 million for amounts collected related to terminal net salvage as discussed in Note 3 of the Notes to Consolidated Financial Statements.

Other current assets decreased $42.6 million due primarily to the manner in which we settled lawsuits discussed in detail in Note 16 of the Notes to Consolidated Financial Statements, "Legal Proceedings." As a result of settling the lawsuits and with our insurance carriers, pending actual cash distributions to the plaintiffs, we had recorded a receivable from our insurer, with an offsetting payable to the plaintiffs. Once payments were made to the plaintiffs, both the receivable and the payable were eliminated.

Other assets decreased $13.2 million due primarily to the elimination of the pension intangible asset of $17.6 million pursuant to the adoption of SFAS No. 158 and $10.2 million associated with the redemption of Guardian International, Inc. (Guardian) preferred stock. This decline was offset partially by a $7.3 million increase associated with assets acquired with the acquisition of the Spring Creek Energy Center.

As of December 31, 2006, we had no current maturities of long-term debt. Current maturities of long-term debt as of December 31, 2005 consisted of the $100.0 million outstanding aggregate principal amount of KGE 6.2% first mortgage bonds that we repaid in January 2006.

We increased our borrowings under the Westar Energy revolving credit facility. As a result our short-term debt increased $160.0 million. We used a portion of the borrowings to repay the KGE first mortgage bonds that were due in January 2006. In addition, we used borrowings under the revolving credit facility to meet our on-going operational needs.

Other current liabilities decreased $29.9 million due primarily to the disbursement of the funds for the settlement of lawsuits as discussed above and as detailed in Note 16 of the Notes to Consolidated Financial Statements, "Legal Proceedings." Upon rebating $10.0 million to customers in 2006, in fulfillment of a 2003 regulatory settlement, we reduced other current liabilities accordingly.

Accrued employee benefits increased $88.5 million due primarily to the additional pension and post-retirement benefit liabilities recorded in 2006 pursuant to the adoption of SFAS No. 158. For additional information, see Notes 12 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans."

Asset retirement obligations decreased $45.7 million due primarily to the remeasurement of our asset retirement obligation for Wolf Creek based on its application for a license extension. For additional information, see Note 15 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations."

During 2006 we implemented SFAS No. 123R, which guides the accounting for equity-based compensation. This caused us to record changes in temporary equity, paid-in capital and unearned compensation. This is discussed in further detail in Note 12 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans."

Accumulated other comprehensive income increased $41.1 million due primarily to the establishment of a regulatory asset for the pension liabilities that were previously charged to accumulated other comprehensive income.

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 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

As of December 31, 2006, we had $18.2 million in unrestricted cash and cash equivalents. In addition, Westar Energy has a $500.0 million revolving credit facility against which $160.0 million had been borrowed and $32.0 million of letters of credit have been issued. This left $308.0 million available under this facility.

The Westar Energy and KGE mortgages each contain provisions restricting the amount of first mortgage bonds that can be issued by each entity. We must comply with such restrictions prior to the issuance of additional first mortgage bonds or other secured indebtedness.

The Westar Energy mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless Westar Energy's unconsolidated net earnings available for interest, depreciation and property retirement (which as defined, does not include earnings or losses attributable to the ownership of securities of subsidiaries), for a period of 12 consecutive months within 15 months preceding the issuance, are not less than the greater of twice the annual interest charges on, and 10% of the principal amount of, all first mortgage bonds outstanding after giving effect to the proposed issuance. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. As of December 31, 2006, based on an assumed interest rate of 6%, $378.8 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

The KGE mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless KGE's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than either two and one-half times the annual interest charges on, or 10% of the principal amount of, all KGE first mortgage bonds outstanding after giving effect to the proposed issuance. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. As of December 31, 2006, based on an assumed interest rate of 6%, approximately $908.1 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 decreased $97.9 million to $256.0 million in 2006, from $353.9 million in 2005. During 2006, we used $72.4 million to pay federal and state income taxes and made a $20.8 million contribution to our defined benefit pension trust. 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. We received $57.4 million in tax refunds during 2005.

Cash flows from operating activities increased $8.3 million to $353.9 million in 2005, from $345.6 million in 2004. 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 (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 $344.9 million in 2006, $212.8 million in 2005 and $197.1 million in 2004 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.

Cash Flows used in Financing Activities

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

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 2005 used $127.9 million of cash compared to $323.2 million in 2004. 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.

Future Cash Requirements

Our business requires significant capital investments. Through 2009, we expect we will need cash mostly for utility construction programs designed to improve facilities providing electric service, for future peaking capacity needs, for construction of new transmission lines and to comply with environmental regulations. We expect to meet these cash needs with internally generated cash flow, borrowings under Westar Energy's revolving credit facility and through the issuance of securities in the capital markets.

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 2006 and anticipated capital expenditures for 2007 through 2009, including costs of removal, are shown in the following table.

	Actual 2006	2007	2008	2009
	(In Thousands)			
Generation:				
Replacements and other	$ 51,343	$ 93,005	$ 133,534	$ 145,199
Additional capacity	74,552	213,537	116,843	33,652
Environmental	47,103	191,987	168,268	128,428
Nuclear fuel	25,716	31,517	19,420	19,901
Transmission	31,537	65,310	104,656	137,366
Distribution:				
Replacements and other	38,409	37,106	56,742	73,794
New customers	64,161	56,175	57,467	58,788
Other	12,039	47,643	18,597	16,633
Total capital expenditures	$ 344,860	$ 736,280	$ 675,527	$ 613,761

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 as of December 31, 2006 are as follows.

Year	Principal Amount
	(In Thousands)
2007	$ —
2008	—
2009	145,078
2010	—
Thereafter	1,421,268
Total long-term debt maturities	$1,566,346

Debt Financings

On June 1, 2006, we refinanced $100.0 million of pollution control bonds, which were to mature in 2031. We replaced this issue with two new pollution control bond series of $50.0 million each. One series carries an interest rate of 4.85% and matures in 2031. The second series carries a variable interest rate and also matures in 2031.

On March 17, 2006, Westar Energy amended and restated the revolving credit facility dated May 6, 2005 to increase the size of the facility, extend the term and reduce borrowing costs. The amended and restated revolving credit facility matures on March 17, 2011. So long as there is no default or event of default under the revolving credit facility, we may elect annually prior to the anniversary date of the facility to extend the term of the credit facility for one year. This one year extension can be requested twice during the term of the facility, subject to lender participation. The facility allows Westar Energy to borrow up to an aggregate amount of $500.0 million, including letters of credit up to a maximum aggregate amount of $150.0 million. We may elect, subject to FERC approval, to increase the aggregate amount of borrowings under the facility to $750.0 million by increasing the commitment of one or more lenders who have agreed to such increase, or by adding one or more new lenders with the consent of the Administrative Agent and any letter of credit issuing bank, which will not be unreasonably withheld, so long as there is no default or event of default under the revolving credit 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 17, 2006, we repaid $100.0 million aggregate principal amount of 6.2% first mortgage bonds with cash on hand and borrowings under the revolving credit facility. On August 1, 2005, we repaid $65.0 million aggregate principal amount of 6.5% first mortgage bonds with cash on hand and borrowings under the 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 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.

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain leverage ratios as defined in the agreements. We calculate these ratios in accordance with our credit agreements. These ratios are used solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2006.

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.

In February 2007, S&P upgraded its credit ratings for our securities as shown in the table below. In May 2006, Moody's Investors Service upgraded its credit ratings for our securities as shown in the table below and changed its outlook for our ratings to stable. In March 2006, Fitch Investors Service upgraded its credit ratings for our securities as shown in the table below and changed its outlook for our ratings to stable.

As of February 26, 2007, 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	Baa2	Baa3	Baa2
Fitch	BBB	BBB-	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 the Westar Energy revolving credit agreement 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

As of December 31, 2006 and 2005, our long-term capital structure was as follows:

	2006	2005
Common equity	49%	45%
Preferred stock	1%	1%
Long-term debt	50%	54%
Total	100%	100%

OFF-BALANCE SHEET ARRANGEMENTS

As of December 31, 2006, we did not have any off-balance sheet financing arrangements, other than our operating leases entered into in the ordinary course of business. For additional information on our operating leases, see Note 21 of the Notes to Consolidated Financial Statements, "Leases."

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

In the course of our business activities, we enter into a variety of obligations and commercial commitments. Some of these result in direct obligations reflected on our consolidated balance sheets while others are commitments, some firm and some based on uncertainties, not reflected in our underlying consolidated financial statements. The obligations listed below include amounts for on-going needs for which contractual obligations existed as of December 31, 2006.

Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2006.

	Total	2007	2008-2009	2010-2011	Thereafter
	(In Thousands)				
Long-term debt[a]	$1,566,346	$ —	$145,078	$ —	$1,421,268
Interest on long-term debt[b]	1,461,210	83,973	167,946	147,272	1,062,019
Adjusted long-term debt	3,027,556	83,973	313,024	147,272	2,483,287
Wolf Creek pension benefit funding obligations[c]	6,300	6,300	—	—	—
Capital leases[d]	21,779	6,162	8,210	4,845	2,562
Operating leases[e]	583,739	35,272	89,064	84,988	374,415
Fossil fuel[f]	1,413,183	218,296	379,957	274,746	540,184
Nuclear fuel[g]	347,493	35,360	37,860	45,205	229,068
Unconditional purchase obligations	176,120	56,441	113,544	6,135	—
Total contractual obligations, including adjusted long-term debt	$5,576,170	$441,804	$941,659	$563,191	$3,629,516

[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 as of December 31, 2006*

[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, rail car leases and other miscellaneous commitments.*

[f] *Coal and natural gas commodity and transportation contracts.*

[g] *Uranium concentrates, conversion, enrichment, fabrication and spent nuclear fuel disposal.*

Commercial Commitments

Our commercial commitments existing as of December 31, 2006 consist of outstanding letters of credit that expire in 2007, some of which automatically renew annually. The letters of credit are comprised of $26.2 million related to our energy marketing and trading activities, $3.4 million related to worker's compensation and $2.7 million related to other operating activities for a total outstanding balance of $32.3 million.

OTHER INFORMATION

Stock Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123R using the modified prospective transition method. Since 2002, we have used RSUs exclusively for our stock-based compensation awards. Given the characteristics of our stock-based compensation awards, the adoption of SFAS No. 123R did not have a material impact on our consolidated results of operations.

Total unrecognized compensation cost related to RSU awards was $4.4 million as of December 31, 2006. We expect to recognize these costs over a remaining weighted-average period of 3.7 years. Upon adoption of SFAS No. 123R, we were required to charge $10.3 million of unearned stock compensation against additional paid-in capital. There were no modifications of awards during the years ended December 31, 2006, 2005 or 2004.

Prior to the adoption of SFAS No. 123R, we reported all tax benefits resulting from the vesting of RSU awards and exercise of stock options as operating cash flows in the consolidated statements of cash flows. SFAS No. 123R requires cash retained as a result of excess tax benefits resulting from the tax deductions in excess of the related compensation cost recognized in the financial statements to be classified as cash flows from financing activities in the consolidated statements of cash flows.

Pension Obligation

We made a $20.8 million voluntary pension contribution to the Westar Energy pension trust in 2006. Based on the January 1, 2006 funding valuation, we are not required to make any contributions to the pension trust during 2007. We currently expect to make a voluntary contribution to the pension trust of an estimated $11.8 million in 2007. We may make additional contributions into the pension trust in 2007 depending on how the funded status of the pension plan changes, regulatory treatment for the contributions and conclusions reached as there is more clarity with respect to the Pension Protection Act of 2006 (PPA) that was signed into law on August 17, 2006. The United States Treasury Department is in the process of developing implementation guidance for the PPA; however, it is likely the PPA will accelerate minimum funding requirements beginning in 2009. We may choose to pre-fund some of the anticipated required funding.

Customer Rebates

We made rebates to customers of $10.0 million in 2006 and $10.5 million during the year ended December 31, 2005, in accordance with a July 25, 2003 KCC Order.

Purchase of Electric Generation Facility

On October 31, 2006, we purchased a 300 MW electric generation facility and related assets from OESC for $53.0 million. As part of this transaction, we entered into an agreement to provide OESC with 75 MW of capacity through 2015.

Agreement to Assume Leasehold Interest in Jeffrey Energy Center

On August 30, 2006, we entered into an agreement with Aquila, Inc. to assume its 8% leasehold interest in Jeffrey Energy Center. We expect this transaction to close in 2007. In relation to this transaction, we entered into a long-term sale agreement with Mid-Kansas Electric Company, LLC (MKEC) pursuant to which we will provide MKEC with the capacity and energy from the 8% leasehold interest in the Jeffrey Energy Center through January 3, 2019. We also agreed to purchase Aquila's materials and supplies, inventory and leasehold improvements at the then unamortized book balance as of the date of closing. We estimate this amount will be approximately $30.0 million. Following the closing of this transaction, our capital expenditures associated with Jeffrey Energy Center will reflect not only the 84% of the station that we own, but also the 8% leasehold interest we assumed from Aquila, Inc.

Impact of Regulatory Accounting

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

As of December 31, 2006, we had recorded regulatory assets currently subject to recovery in future rates of approximately $609.5 million and regulatory liabilities of $133.5 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

Legal Liability

In accordance with SFAS No. 143 and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), we have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of an asset retirement obligation is capitalized and depreciated over the remaining life of the asset.

We have recorded asset retirement obligations at fair value for the estimated cost to: decommission Wolf Creek (our 47% share); 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, 2006 and 2005, we have recorded asset retirement obligations of $84.2 million and $129.9 million, respectively. 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. As of December 31, 2006 and 2005, we had $13.4 million and $6.9 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 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 recognized a gain of approximately $0.3 million as a result of this transaction. 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 either Mr. Wittig or Mr. Lake, as well as related dividends, and now the cash received for the shares, is disputed and is the subject of the arbitration proceeding with Mr. Wittig and Mr. Lake discussed in Note 16, "Legal Proceedings." These shares were, and now the cash received for the shares are, also part of the property forfeited by Mr. Wittig and Mr. Lake in the criminal proceeding discussed in Note 18, "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

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

In February 2007, the Financial Accounting Standards Board (FASB) released SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment to FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. A business entity shall report unrealized gains and losses on items for which fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We anticipate adopting the guidance effective January 1, 2008. We are currently evaluating what impact the adoption of SFAS No. 159 will have on our consolidated financial statements.

SFAS No. 157 — Fair Value Measurements

In September 2006, FASB released SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We anticipate adopting the guidance effective January 1, 2008. We are currently evaluating what impact the adoption of SFAS No. 157 will have on our consolidated financial statements.

FIN 48 — Accounting for Uncertainty in Income Taxes

In July 2006, FASB released FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109." FIN 48 prescribes a comprehensive model for how companies should recognize, measure and disclose in their financial statements uncertain tax positions taken, or expected to be taken, on a tax return. It also provides guidance on derecognizing, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006 with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings.

We will adopt the guidance effective January 1, 2007. As of this date, we continue to evaluate what impact the adoption of FIN 48 will have on our consolidated financial statements. We do not expect the adoption of FIN 48 to have a material impact on our consolidated financial statements.

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.

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 2007.

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 calculation has been adjusted to remove the impact of fuel contracts due to implementation of the RECA in 2006. The VaR amounts for 2006 and 2005 were as follows.

	2006	2005
	(In Thousands)	
High	$2,178	$2,690
Low	449	471
Average	1,089	1,398

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 unscheduled outages at our facilities that use fossil fuels and the nuclear refueling schedule. Our customers' electricity usage could also vary from year to year based on 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." We compute and present information about the sensitivity to changes in interest rates for variable rate debt and current maturities of fixed rate debt by assuming a 100 basis point change in the current interest rate applicable to such debt over the remaining time the debt is outstanding.

We had approximately $431.9 million of variable rate debt as of December 31, 2006. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $4.3 million. In addition, a decline in interest rates generally can serve to increase our pension and post retirement obligations and affect investment returns.

Security Price Risk

We maintain trust funds, as required by the NRC and Kansas state laws, to fund certain costs of nuclear plant decommissioning. As of December 31, 2006, these funds were comprised of 63% equity securities, 33% debt securities and 4% cash and cash equivalents. The fair value of these funds was $111.1 million as of December 31, 2006 and $100.8 million as of December 31, 2005. By maintaining a diversified portfolio of securities, we seek to maximize the returns to fund the decommissioning obligation within acceptable risk tolerances. However, debt and equity securities in the portfolio are exposed to price fluctuations in the capital markets. If the value of the securities diminishes, the cost of funding the obligation rises. We actively monitor the portfolio by benchmarking the performance of the investments against relevant indices and by maintaining and periodically reviewing the asset allocation in relation to established policy targets. Our exposure to equity price market risk is, in part, mitigated because we are currently allowed to recover decommissioning costs in the rates we charge our customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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SCHEDULES OMITTED

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

I, III, IV, and V.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

We assessed the effectiveness of our internal control over financial reporting as of December 31, 2006. 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, as of December 31, 2006, 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.

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 its subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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 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.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, 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, 2006, 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, 2006 of the Company and our report dated February 28, 2007 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's adoption of new accounting standards.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 28, 2007

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, 2006 and 2005, 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, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 12 to the financial statements, in 2006, the Company adopted Statement of Financial Accounting Standard No. 123(R), "Share-Based Payment," and Statement of Financial Accounting Standard No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."

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, 2006, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2007 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
February 28, 2007

WESTAR ENERGY, INC. CONSOLIDATED BALANCE SHEETS

As of December 31,	2006	2005
(Dollars in Thousands)		
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 18,196	$ 38,539
Restricted cash	—	2,430
Accounts receivable, net	179,859	124,711
Inventories and supplies, net	147,930	101,818
Energy marketing contracts	67,267	55,948
Tax receivable	15,142	1,565
Deferred tax assets	853	19,211
Prepaid expenses	29,620	30,452
Regulatory assets	58,777	39,300
Other	19,076	61,646
Total Current Assets	536,720	475,620
PROPERTY, PLANT AND EQUIPMENT, NET	4,071,607	3,947,732
OTHER ASSETS:		
Restricted cash	—	25,014
Regulatory assets	550,703	398,198
Nuclear decommissioning trust	111,135	100,803
Energy marketing contracts	11,173	75,698
Other	173,837	187,004
Total Other Assets	846,848	786,717
TOTAL ASSETS	$5,455,175	$ 5,210,069
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ —	$ 100,000
Short-term debt	160,000	—
Accounts payable	150,424	109,807
Accrued taxes	102,219	100,568
Energy marketing contracts	57,281	11,710
Accrued interest	32,928	36,609
Regulatory liabilities	49,836	50,970
Other	110,488	140,403
Total Current Liabilities	663,176	550,067
LONG-TERM LIABILITIES:		
Long-term debt, net	1,563,265	1,562,990
Deferred income taxes	906,311	911,135
Unamortized investment tax credits	61,668	65,558
Deferred gain from sale-leaseback	125,017	130,513
Accrued employee benefits	246,930	158,418
Asset retirement obligations	84,192	129,888
Energy marketing contracts	534	2,007
Regulatory liabilities	83,664	111,523
Other	152,852	150,531
Total Long-Term Liabilities	3,224,433	3,222,563
COMMITMENTS AND CONTINGENCIES (see Notes 14 and 16)		
TEMPORARY EQUITY (See Note 12)	6,671	—
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 87,394,886 shares and 86,835,371 shares, respectively	436,974	434,177
Paid-in capital	916,605	923,083
Unearned compensation	—	(10,257)
Retained earnings	185,779	109,987
Accumulated other comprehensive income (loss), net	101	(40,987)
Total Shareholders' Equity	1,560,895	1,437,439
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$5,455,175	$ 5,210,069

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31,	**2006**	2005	2004
(Dollars in Thousands, Except Per Share Amounts)			
SALES	**$1,605,743**	$ 1,583,278	$ 1,464,489
OPERATING EXPENSES:			
Fuel and purchased power	**483,959**	528,229	419,788
Operating and maintenance	**463,785**	437,741	412,002
Depreciation and amortization	**180,228**	150,520	169,310
Selling, general and administrative	**171,001**	166,060	173,498
Total Operating Expenses	**1,298,973**	1,282,550	1,174,598
INCOME FROM OPERATIONS	**306,770**	300,728	289,891
OTHER INCOME (EXPENSE):			
Investment earnings	**9,212**	11,365	16,746
Loss on extinguishment of debt	**—**	—	(18,840)
Other income	**18,000**	9,948	2,756
Other expense	**(13,711)**	(17,580)	(14,879)
Total Other Income (Expense)	**13,501**	3,733	(14,217)
Interest expense	**98,650**	109,080	142,151
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**221,621**	195,381	133,523
Income tax expense	**56,312**	60,513	33,443
INCOME FROM CONTINUING OPERATIONS	**165,309**	134,868	100,080
Results of discontinued operations, net of tax	**—**	742	78,790
NET INCOME	**165,309**	135,610	178,870
Preferred dividends	**970**	970	970
EARNINGS AVAILABLE FOR COMMON STOCK	**$ 164,339**	$ 134,640	$ 177,900
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (see Note 2):			
Basic earnings available from continuing operations	**$ 1.88**	$ 1.54	$ 1.19
Discontinued operations, net of tax	**—**	0.01	0.95
Basic earnings available	**$ 1.88**	$ 1.55	$ 2.14
Diluted earnings available from continuing operations	**$ 1.87**	$ 1.53	$ 1.19
Discontinued operations, net of tax	**—**	0.01	0.94
Diluted earnings available	**$ 1.87**	$ 1.54	$ 2.13
Average equivalent common shares outstanding	**87,509,800**	86,855,485	82,941,374
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.00**	$ 0.92	$ 0.80

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31,	**2006**	2005	2004
(Dollars in Thousands)			
NET INCOME	**$ 165,309**	$ 135,610	$ 178,870
OTHER COMPREHENSIVE INCOME (LOSS):			
Unrealized holding (loss) gain on marketable securities arising during the period	**(57)**	45	11
Minimum pension liability adjustment	**31,841**	(68,321)	7,769
Other comprehensive income (loss), before tax	**31,784**	(68,276)	7,780
Income tax (expense) benefit related to items of other comprehensive income	**(12,666)**	27,176	(3,090)
Other comprehensive income (loss), net of tax	**19,118**	(41,100)	4,690
COMPREHENSIVE INCOME	**$ 184,427**	$ 94,510	$ 183,560

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31,	**2006**	2005	2004
(Dollars in Thousands)			
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	**$ 165,309**	$ 135,610	$ 178,870
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations, net of tax	**—**	(742)	(78,790)
Depreciation and amortization	**180,228**	150,520	169,310
Amortization of nuclear fuel	**13,851**	13,315	14,221
Amortization of deferred gain from sale-leaseback	**(5,495)**	(8,469)	(11,828)
Amortization of corporate-owned life insurance	**15,336**	16,265	12,622
Non-cash stock compensation	**3,389**	3,219	7,916
Net changes in energy marketing assets and liabilities	**(7,505)**	5,799	4,383
Loss on extinguishment of debt	**—**	—	18,840
Accrued liability to certain former officers	**3,813**	2,018	8,384
Gain on sale of utility plant and property	**(570)**	—	(503)
Net deferred income taxes and credits	**(4,203)**	25,552	(5,215)
Stock based compensation excess tax benefits	**(854)**	—	—
Changes in working capital items, net of acquisitions and dispositions:			
Accounts receivable, net	**(55,148)**	(32,179)	(11,561)
Inventories and supplies	**(46,112)**	22,745	10,368
Prepaid expenses and other	**(4,095)**	(65,635)	(35,114)
Accounts payable	**22,625**	6,929	6,439
Accrued taxes	**(13,160)**	91,938	43,463
Other current liabilities	**(5,708)**	(20,876)	(5,907)
Changes in other assets	**19,412**	20,374	12,846
Changes in other liabilities	**(25,127)**	(12,492)	6,880
Cash flows from operating activities	**255,986**	353,891	345,624
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	**(344,860)**	(212,814)	(197,149)
Purchase of securities within the nuclear decommissioning trust fund	**(345,541)**	(372,426)	(313,241)
Sale of securities within the nuclear decommissioning trust fund	**341,410**	367,570	309,105
Investment in corporate-owned life insurance	**(19,127)**	(19,346)	(19,658)
Proceeds from investment in corporate-owned life insurance	**22,684**	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	**1,695**	—	8,604
Proceeds from sale of international investment	**—**	—	11,219
Issuance of officer loans and interest, net of payments	**—**	—	2
Proceeds from other investments	**53,411**	13,990	16,548
Cash flows used in investing activities	**(290,328)**	(212,029)	(76,260)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	**160,000**	—	(1,000)
Proceeds from long-term debt	**99,662**	642,807	623,301
Retirements of long-term debt	**(200,000)**	(741,847)	(1,188,081)
Funds in trust for debt repayments	**—**	—	78
Repayment of capital leases	**(4,813)**	(4,898)	(4,977)
Borrowings against cash surrender value of corporate-owned life insurance	**59,697**	58,039	57,090
Repayment of borrowings against cash surrender value of corporate-owned life insurance	**(24,133)**	(13,026)	(444)
Stock based compensation excess tax benefits	**854**	—	—
Issuance of common stock, net	**2,394**	5,584	245,130
Cash dividends paid	**(80,894)**	(74,593)	(56,189)
Reissuance of treasury stock	**—**	—	1,927
Cash flows from (used in) financing activities	**12,767**	(127,934)	(323,165)
CASH FLOWS FROM (USED IN) DISCONTINUED OPERATIONS:			
Cash flows from operating activities	**—**	—	2,265
Cash flows from (used in) investing activities	**1,232**	—	(3,412)
Net cash from (used in) discontinued operations	**1,232**	—	(1,147)
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(20,343)**	13,928	(54,948)
CASH AND CASH EQUIVALENTS:			
Beginning of period	**38,539**	24,611	79,559
End of period	**$ 18,196**	$ 38,539	$ 24,611

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Cumulative Preferred Stock	Common Stock	Paid-in Capital	Unearned Compensation	Loans to Officers	Retained Earnings (Accumulated Deficit)	Treasury Stock	Accumulated Other Comprehensive (Loss) Income	Total Shareholders' Equity
				(Dollars in Thousands)					
BALANCE AT DECEMBER 31, 2003	$ 21,436	$364,201	$776,754	$ (15,879)	$ (2)	$(102,782)	$ (2,391)	$ (4,577)	$1,036,760
Net income	—	—	—	—	—	178,870	—	—	178,870
Issuance of common stock, net	—	65,948	192,337	—	—	—	—	—	258,285
Preferred dividends, net of retirements	—	—	653	—	—	(1,074)	—	—	(421)
Dividends on common stock	—	—	(46,473)	—	—	(19,786)	—	—	(66,259)
Issuance of treasury stock	—	—	1,230	—	—	(175)	2,391	—	3,446
Grant of restricted stock	—	—	1,417	(1,417)	—	—	—	—	—
Amortization of restricted stock	—	—	—	6,838	—	—	—	—	6,838
Forfeited restricted stock	—	—	—	97	—	—	—	—	97
Stock compensation	—	—	(12,986)	—	—	—	—	—	(12,986)
Issuance of officer loans and interest, net of payments	—	—	—	—	2	—	—	—	2
Unrealized gain on marketable securities	—	—	—	—	—	—	—	11	11
Minimum pension liability adjustment	—	—	—	—	—	—	—	7,769	7,769
Income tax expense	—	—	—	—	—	—	—	(3,090)	(3,090)
BALANCE AT DECEMBER 31, 2004	21,436	430,149	912,932	(10,361)	—	55,053	—	113	1,409,322
Net income	—	—	—	—	—	135,610	—	—	135,610
Issuance of common stock, net	—	4,028	13,171	—	—	—	—	—	17,199
Preferred dividends, net of retirements	—	—	—	—	—	(970)	—	—	(970)
Dividends on common stock	—	—	—	—	—	(79,706)	—	—	(79,706)
Grant of restricted stock	—	—	2,986	(2,986)	—	—	—	—	—
Amortization of restricted stock	—	—	—	3,019	—	—	—	—	3,019
Forfeited restricted stock	—	—	—	71	—	—	—	—	71
Stock compensation and tax benefit	—	—	(6,006)	—	—	—	—	—	(6,006)
Unrealized gain on marketable securities	—	—	—	—	—	—	—	45	45
Minimum pension liability adjustment	—	—	—	—	—	—	—	(68,321)	(68,321)
Income tax benefit	—	—	—	—	—	—	—	27,176	27,176
BALANCE AT DECEMBER 31, 2005	**21,436**	**434,177**	**923,083**	**(10,257)**	**—**	**109,987**	**—**	**(40,987)**	**1,437,439**
Net income	**—**	**—**	**—**	**—**	**—**	**165,309**	**—**	**—**	**165,309**
Issuance of common stock, net	**—**	**2,797**	**9,585**	**—**	**—**	**—**	**—**	**—**	**12,382**
Preferred dividends, net of retirements	**—**	**—**	**—**	**—**	**—**	**(970)**	**—**	**—**	**(970)**
Dividends on common stock	**—**	**—**	**—**	**—**	**—**	**(88,547)**	**—**	**—**	**(88,547)**
Reclass to Temporary Equity	**—**	**—**	**(6,671)**	**—**	**—**	**—**	**—**	**—**	**(6,671)**
Reclass of unearned compensation	**—**	**—**	**(10,257)**	**10,257**	**—**	**—**	**—**	**—**	**—**
Amortization of restricted stock	**—**	**—**	**2,956**	**—**	**—**	**—**	**—**	**—**	**2,956**
Stock compensation and tax benefit	**—**	**—**	**(2,091)**	**—**	**—**	**—**	**—**	**—**	**(2,091)**
Unrealized loss on marketable securities	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(57)**	**(57)**
Minimum pension liability adjustment	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**31,841**	**31,841**
Income tax expense	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(12,666)**	**(12,666)**
Reclass to regulatory asset	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**21,970**	**21,970**
BALANCE AT DECEMBER 31, 2006	**$ 21,436**	**$436,974**	**$916,605**	**$ —**	**$ —**	**$ 185,779**	**$ —**	**$ 101**	**$1,560,895**

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 669,000 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. Undivided interests in jointly-owned generation facilities are included on a proportionate basis. Intercompany accounts and transactions have been eliminated in consolidation. In our opinion, all adjustments, consisting only of normal recurring adjustments considered necessary for a fair presentation of the financial statements, have been included.

Use of Management's Estimates

When we prepare our consolidated financial statements, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities at the date of our consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an on-going basis, including those related to bad debts, inventories, valuation of commodity contracts, depreciation, unbilled revenue, investments, valuation of our energy marketing portfolio, intangible assets, fuel costs billed under the terms of our retail energy cost adjustment (RECA), 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 apply accounting standards for our regulated utility operations that recognize the economic effects of rate regulation in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and, accordingly, have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent.

Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities represent probable future reductions in revenue or refunds to customers through the rate making process. Regulatory assets and liabilities reflected on our consolidated balance sheets are as follows.

As of December 31,	2006	2005
	(In Thousands)	
Regulatory Assets:		
Amounts due from customers for future income taxes, net	$160,147	$166,632
Debt reacquisition costs	97,342	103,563
Deferred employee benefit costs	189,226	4,160
Disallowed plant costs	16,733	16,929
2002 ice storm costs	14,897	19,389
2005 ice storm costs	24,540	30,878
Asset retirement obligations	19,312	18,686
Depreciation	58,863	49,894
Property taxes	181	10,462
Wolf Creek outage	14,975	9,915
Retail energy cost adjustment	6,950	—
Other regulatory assets	6,314	6,990
Total regulatory assets	$609,480	$437,498
Regulatory Liabilities:		
Fuel supply contracts	$ 12,794	$117,668
Nuclear decommissioning	48,793	16,048
Retail energy cost adjustment	19,884	—
State Line purchased power	6,623	8,109
Terminal net salvage	16,439	—
Removal costs	13,355	6,888
Other regulatory liabilities	15,612	13,780
Total regulatory liabilities	$133,500	$162,493

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, thereby passing on these benefits to customers at the time we receive them. We believe it is probable that the net future increases in income taxes payable will be recovered from customers when these temporary tax benefits reverse in future periods. We have recorded a regulatory asset for these amounts. We also have recorded a regulatory liability for our obligation to customers for taxes recovered from customers in earlier periods when corporate tax rates were higher than the current tax rates.

The benefit will be returned to customers as these temporary differences reverse in future periods. The tax-related regulatory assets and liabilities as well as unamortized investment tax credits are also temporary differences for which deferred income taxes have been provided. These items are measured by the expected cash flows to be received or settled through future rates.

- **Debt reacquisition costs:** This includes costs incurred to reacquire and refinance debt. Debt reacquisition costs are amortized over the term of the new debt.
- **Deferred employee benefit costs:** Employee benefit costs include \$189.4 million, less \$3.1 million for applicable taxes, for pension and post-retirement benefit obligations pursuant to SFAS No. 158 and \$2.9 million for post-retirement expenses in excess of amounts paid. We will amortize to expense approximately \$17.6 million during 2007 for the benefit obligation. The post-retirement expenses are recovered over a period of five years.
- **Disallowed plant costs:** In 1985, the Kansas Corporation Commission (KCC) disallowed certain costs associated with the original construction of Wolf Creek. In 1987, the KCC authorized KGE to recover these costs in rates over the useful life of Wolf Creek.
- **2002 ice storm costs:** We accumulated and deferred for later recovery costs related to restoring our electric distribution system from the damage it suffered as a result of an ice storm that occurred in January 2002. The KCC authorized us to accrue carrying costs on this item. As allowed by the December 28, 2005 KCC Order, in 2006 Westar Energy began recovering \$7.7 million over a three year period and KGE began recovering \$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 restoring our electric distribution system from the damage it sustained as a result of a subsequent, more severe, ice storm that occurred in January 2005. The KCC authorized us to accrue carrying costs on this item. As allowed by the December 28, 2005 KCC Order, in 2006 Westar Energy began recovering \$5.6 million over a three year period and KGE began recovering \$25.3 million over a five year period. We earn a return on this asset.
- **Asset retirement obligations:** This 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:** This represents the difference between the regulatory depreciation expense and the depreciation expense we record for financial reporting purposes. We earn a return on this asset. We recover this item over the life of the related utility plant.
- **Property taxes:** We are allowed to adjust our rates to recover an amount equal to the property taxes we must pay. This item represents the amount we have paid for property taxes that we have not yet collected from customers. We expect to recover this shortfall over a one year period.
- **Wolf Creek outage:** Wolf Creek incurs a refueling and maintenance outage approximately every 18 months. The expenses associated with these maintenance and refueling outages are deferred and amortized over the period of time between such planned outages.
- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. This item represents the difference in the actual cost of fuel consumed in producing electricity and the cost of purchased power and amounts we have collected from customers. We expect to recover in our rates this shortfall over a one year period.
- **Other regulatory assets:** This item includes various regulatory assets that individually are small in relation to the total regulatory asset balance. Other regulatory assets have various recovery periods, most of which range from three to five years.

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

- **Fuel supply contracts:** We use mark to market accounting for some of our fuel contracts. This item 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." Under the RECA, fuel contract market gains accrue to the benefit of our customers.
- **Nuclear decommissioning:** We have a legal obligation to decommission Wolf Creek at the end of its useful life. This amount represents the difference between the fair value of our asset retirement obligation and the fair value of the assets in our decommissioning trust. See Note 6, "Financial Investments and Trading Securities" and Note 15, "Asset Retirement Obligations," for information regarding our Nuclear Decommissioning Trust Fund and our asset retirement obligation.
- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. We bill customers based on our estimated costs. This item represents the amount we collected from customers that was in excess of our actual cost of fuel and purchased power. We will refund to customers this excess recovery over a one year period.
- **State Line purchased power:** This represents amounts received from customers in excess of costs incurred under Westar Energy's purchased power agreement with Westar Generating, Inc., a wholly owned subsidiary.
- **Terminal net salvage:** This represents amounts collected in rates for terminal net salvage. Pursuant to the February 8, 2007 KCC Order, the KCC ordered us to refund amounts previously collected. We expect to refund this amount during 2007.
- **Removal costs:** This represents amounts collected, but unspent, for costs to dispose of utility plant assets that do not represent legal retirement obligations. The liability will be discharged as removal costs are incurred.
- **Other regulatory liabilities:** This includes various regulatory liabilities that individually are relatively small in relation to the total regulatory liability balance. Other regulatory liabilities will be credited over various periods, most of which range from one to five years.

Cash and Cash Equivalents

We consider investments that are highly liquid and that have maturities of three months or less when purchased to be cash equivalents.

Restricted Cash

Restricted cash consists of cash irrevocably deposited in trust for a prepaid capacity and transmission agreement.

Accounts Receivable

Receivables, which consist primarily of trade accounts receivable, were reduced by allowances for doubtful accounts of $6.3 million at December 31, 2006, and $5.2 million at December 31, 2005.

Inventories and Supplies

We state inventories and supplies at average cost.

Property, Plant and Equipment

We record the value of property, plant and equipment at cost. For utility plant, cost includes contracted services, direct labor and materials, indirect charges for engineering and supervision, and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of funds used to finance construction projects. The AFUDC rate was 5.3% in 2006, 4.2% in 2005 and 3.8% in 2004. We capitalize the cost of additions to utility plant and replacement units of property. We capitalized AFUDC of $4.1 million in 2006, $2.7 million in 2005 and $1.8 million in 2004.

We charge maintenance costs and replacement of minor items of property to expense as incurred, except for maintenance costs incurred for our refueling outages at Wolf Creek. As authorized by regulators, we amortize these amounts to expense ratably over the 18-month period between such scheduled outages. Normally, when a unit of depreciable property is retired, we charge to accumulated depreciation the original cost, less salvage value.

Depreciation

We depreciate utility plant using a straight-line method at rates based on the estimated remaining useful lives of the assets. These rates are based on an average annual composite basis using group rates that approximated 2.7% in 2006, 2.5% in 2005 and 2.6% in 2004.

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

	Years
Fossil fuel generating facilities	15 to 75
Nuclear fuel generating facility	40 to 60
Transmission facilities	42 to 65
Distribution facilities	19 to 65
Other	5 to 35

In its order on December 28, 2005, the KCC approved a change in our depreciation rates. This change increased our depreciation expense by approximately $8.8 million.

Nuclear Fuel

We record as property, plant and equipment our share of the cost of nuclear fuel used in the process of refinement, conversion, enrichment and fabrication. We reflect this at original cost and amortize such amounts to fuel expense based on the quantity of heat consumed during the generation of electricity, as measured in millions of British thermal units (MMBtu). The accumulated amortization of nuclear fuel in the reactor was $19.6 million as of December 31, 2006 and $24.2 million as of December 31, 2005. Spent nuclear fuel charged to fuel and purchased power was $18.8 million in 2006, $18.0 million in 2005 and $19.3 million in 2004.

Cash Surrender Value of Life Insurance

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

As of December 31,	2006	2005
	(In Thousands)	
Cash surrender value of policies	$1,053,231	$1,014,198
Borrowings against policies	(971,892)	(936,329)
Corporate-owned life insurance, net	$ 81,339	$ 77,869

We record income for increases in cash surrender value and death proceeds. We offset against policy income the interest expense that we incur on policy loans. Income recognized from death proceeds is highly variable from period to period. Death benefits approximated $18.9 million in 2006, $9.5 million in 2005 and $2.0 million in 2004.

Revenue Recognition — Energy Sales

We record revenue as electricity is delivered. Amounts delivered to individual customers are determined through the systematic monthly readings of customer meters. At the end of each month, the electric usage from the last meter reading is estimated and corresponding unbilled revenue is recorded.

The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $38.4 million as of December 31, 2006 and $42.1 million as of December 31, 2005.

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.

Sales Taxes

We account for the collection and remittance of sales tax on a net basis. As a result, these amounts are not reflected in the consolidated statements of income.

Dilutive Shares

We report basic earnings per share applicable to equivalent common stock based on the weighted average number of common shares outstanding and shares issuable in connection with vested restricted share units (RSU) during the period reported. Diluted earnings per share 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,	2006	2005	2004
DENOMINATOR FOR BASIC AND DILUTED EARNINGS PER SHARE:			
Denominator for basic earnings per share — weighted average equivalent shares	87,509,800	86,855,485	82,941,374
Effect of dilutive securities:			
Employee stock purchase plan shares	—	—	17,515
Employee stock options	788	1,750	1,943
Restricted share units	589,352	552,423	680,216
Denominator for diluted earnings per share — weighted average shares	88,099,940	87,409,658	83,641,048
Potentially dilutive shares not included in the denominator because they are antidilutive	158,080	214,340	217,375

Supplemental Cash Flow Information

Year Ended December 31,	2006	2005	2004
		(In Thousands)	
CASH PAID FOR:			
Interest on financing activities, net of amount capitalized	$ 88,872	$ 87,634	$ 127,993
Income taxes	72,407	772	1,162
NON-CASH INVESTING TRANSATIONS:			
Property, plant and equipment additions	29,134	10,800	13,513
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and RSUs	10,094	11,728	14,674
Assets acquired through capital leases	4,491	3,716	3,272

New Accounting Pronouncements

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

In February 2007, the Financial Accounting Standards Board (FASB) released SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment to FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. A business entity shall report unrealized gains and losses on items for which fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We anticipate adopting the guidance effective January 1, 2008. We are currently evaluating what impact the adoption of SFAS No. 159 will have on our consolidated financial statements.

SFAS No. 157 — Fair Value Measurements

In September 2006, FASB released SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We anticipate adopting the guidance effective January 1, 2008. We are currently evaluating what impact the adoption of SFAS No. 157 will have on our consolidated financial statements.

FIN 48 — Accounting for Uncertainty in Income Taxes

In July 2006, FASB released FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109." FIN 48 prescribes a comprehensive model for how companies should recognize, measure and disclose in their financial statements uncertain tax positions taken, or expected to be taken, on a tax return. It also provides guidance on derecognizing, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006 with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings.

We will adopt the guidance effective January 1, 2007. As of this date, we continue to evaluate what impact the adoption of FIN 48 will have on our consolidated financial statements. We do not expect the adoption of FIN 48 to have a material impact on our consolidated financial statements.

3. RATE MATTERS AND REGULATION

Changes in Rates

In accordance with a 2003 KCC Order, on May 2, 2005, we filed applications with the KCC for it to review our retail electric rates. On December 28, 2005, the KCC issued an order (2005 KCC Order) authorizing changes in our rates, which we began billing in the first quarter of 2006, and approving various other changes in our rate structures. In April 2006, interveners to the rate review filed appeals with the Kansas Court of Appeals challenging various aspects of the 2005 KCC Order. On July 7, 2006, the Kansas Court of Appeals reversed and remanded for further consideration by the KCC three elements of the 2005 KCC Order. The balance of the 2005 KCC Order was upheld.

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

On February 8, 2007, the KCC issued an order in response to the Kansas Court of Appeals' decision regarding the 2005 KCC Order. In its February 8, 2007 Order the KCC: (i) confirmed its original decision regarding its treatment of the La Cygne unit 2 sale-leaseback transaction; (ii) in lieu of a transmission delivery charge, ruled that it intends to permit us to recover our transmission related costs in a manner similar to how we recover our other costs; and (iii) reversed itself with regard to the inclusion in depreciation rates of a component for terminal net salvage. The February 8, 2007 KCC Order requires us to refund to our customers the amount we have collected related to terminal net salvage. We have recorded a regulatory liability at December 31, 2006 in the amount of $16.4 million related to this item.

FERC Proceedings

Request for Change in Transmission Rates

On May 2, 2005, we filed applications with the Federal Energy Regulatory Commission (FERC) that proposed a formula transmission rate providing for annual adjustments to our transmission costs. This is consistent with our proposals filed with the KCC on May 2, 2005 to charge retail customers separately for transmission service through a transmission delivery charge. The proposed FERC transmission rates became effective, subject to refund, December 1, 2005. On November 7, 2006 FERC issued an order reflecting the unanimous settlement reached by the parties to the proceeding. The settlement modified the rates we proposed and requires us to refund $3.4 million, which includes the amount we collected in the interim rates since December 2005 and interest on that amount.

4. ACCOUNTS RECEIVABLE SALES PROGRAM

We terminated our accounts receivable sales program in March 2006. The receivables sold by WR Receivables, Inc. (WR Receivables), our wholly owned subsidiary, during 2005 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 as of December 31, 2005. We recorded this activity on the consolidated statements of cash flows for the year ended December 31, 2005 in the "accounts receivable, net" line of cash flows from operating activities.

The following table summarizes accounts receivable information for WR Receivables.

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

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

As of December 31,	2005
	(In Thousands)
Customer accounts receivable	$128,868
Allowance for uncollectible accounts	(4,933)
Customer accounts receivable, net	123,935
Other accounts receivable	1,076
Other allowance for uncollectible accounts	(300)
Total balance sheet accounts receivable, net	124,711
Customer accounts receivable sold	65,000
Total accounts receivable managed	$189,711
Net uncollectible accounts written off	$ 3,862
Delinquent customer accounts receivable over 60 days	$ 2,994

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 as of December 31, 2006 and 2005. 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.

We base estimates of fair value on information available as of December 31, 2006 and 2005. 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,	2006	2005	2006	2005
	(In Thousands)			
Fixed-rate debt, net of current maturities	$1,294,405	$1,344,406	$1,277,497	$1,339,452

Derivative Instruments

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.

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

The prices we use to value 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.

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. There was an unrealized gain of $1.7 million as of December 31, 2006 and an unrealized loss of $0.3 million as of December 31, 2005.

Available-for-Sale Securities

We hold investments in debt and equity securities in a trust fund for the purpose of funding the decommissioning of Wolf Creek. We have classified these investments in debt and equity securities as available-for-sale and have recorded all such investments at their fair market value as of December 31, 2006 and 2005. Investments by the nuclear decommissioning trust fund are allocated 63% to equity securities, 33% to fixed-income securities and 4% to cash and cash equivalents. Fixed-income investments are limited to U.S. government or agency securities, municipal bonds, or corporate securities. Using the specific identification method to determine cost, the gross realized gains on those sales were $7.5 million in 2006, $3.2 million in 2005 and $4.3 million in 2004. We reflect net realized and unrealized gains and losses in regulatory liabilities on our consolidated balance sheets. This reporting is consistent with the method we use to account for the decommissioning costs 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 reflected 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 as of December 31, 2006 and 2005. 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.

		Gross Unrealized		
Security Type	Cost	Gain	Loss	Fair Value
		(In Thousands)		
2006:				
Debt securities	$ 36,947	$ 181	$ —	$ 37,128
Equity securities	57,202	12,466	—	69,668
Cash equivalents	4,339	—	—	4,339
Total	$ 98,488	$ 12,647	$ —	$ 111,135
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

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

As of December 31, 2006	Cost	Fair Value
	(In Thousands)	
Less than 5 years	$ 3,314	$ 3,315
5 years to 10 years	6,549	6,536
Due after 10 years	16,903	16,892
Sub-total	26,766	26,743
Fixed Income Fund	10,181	10,385
Total	$ 36,947	$ 37,128

The following table presents the fair value and the gross unrealized losses of the available-for-sale securities held in the nuclear decommissioning trust fund that were not deemed to be other-than-temporarily impaired, aggregated by investment category and the length of time that individual securities have been in a continuous unrealized loss position, at December 31, 2006.

	Less than 12 Months		12 Months or Greater		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
			(In Thousands)			
Debt securities	$ 8,931	$ (152)	$ 738	$(14)	$ 9,669	$ (166)
Equity securities	9,006	(1,214)	282	(44)	9,288	(1,258)
Total	$17,937	$(1,366)	$1,020	$(58)	$18,957	$(1,424)

7. PROPERTY, PLANT AND EQUIPMENT

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

As of December 31,	2006	2005
	(In Thousands)	
Electric plant in service	$ 6,066,954	$ 5,937,760
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(2,979,159)	(2,880,613)
	3,890,113	3,859,465
Construction work in progress	142,351	60,561
Nuclear fuel, net	39,109	27,672
Net utility plant	4,071,573	3,947,698
Non-utility plant in service	34	34
Net property, plant and equipment	$ 4,071,607	$ 3,947,732

We recorded depreciation expense on utility property, plant and equipment of $159.9 million in 2006, $130.1 million in 2005 and $148.9 million in 2004.

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 as of December 31, 2006 is shown in the table below.

	Our Ownership as of December 31, 2006					
	In-Service Dates	Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percent
			(Dollars in Thousands)			
La Cygne unit 1[(a)]	June 1973	$ 228,369	$127,152	$32,530	370.0	50
Jeffrey unit 1[(b)]	July 1978	318,661	170,761	6,590	613.0	84
Jeffrey unit 2[(b)]	May 1980	307,681	152,351	5,152	613.0	84
Jeffrey unit 3[(b)]	May 1983	455,668	213,076	4,907	613.0	84
Jeffrey wind 1[(b)]	May 1999	874	328	—	0.6	84
Jeffrey wind 2[(b)]	May 1999	874	328	—	0.6	84
Wolf Creek[(c)]	Sept. 1985	1,401,443	628,965	28,661	548.0	47
State Line[(d)]	June 2001	106,571	23,850	362	204.0	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. We include in operating expenses on our consolidated statements of income our share of operating expenses of the above plants, as well as such expenses for a 50% undivided interest in La Cygne unit 2 (representing 341 MW capacity) sold and leased back to KGE in 1987. 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 $500.0 million. The facility matures on March 17, 2011. So long as there is no default or event of default under the revolving credit facility, we may elect to extend the term of the credit facility for one year. This one year extension can be requested twice during the term of the facility, subject to lender participation. The facility allows us to borrow up to an aggregate amount of $500.0 million, including letters of credit up to a maximum aggregate amount of $150.0 million. We may elect, subject to FERC approval, to increase the aggregate amount of borrowings under the facility to $750.0 million by increasing the commitment of one or more lenders who have agreed to such increase, or by adding one or more new lenders with the consent of the Administrative Agent and any letter of credit issuing bank, which will not be unreasonably withheld, so long as there is no default or event of default under the revolving credit facility. As of December 31, 2006, we had borrowings of $160.0 million and $32.0 million of letters of credit outstanding under this facility.

Information regarding our short-term borrowings is as follows.

As of December 31,	2006	2005
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$122,392	$9,661
Weighted daily average interest rates during the year, excluding fees	5.71%	4.77%

Our interest expense on short-term debt was $7.6 million in 2006, $1.3 million in 2005 and $1.1 million in 2004.

10. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

As of December 31,	2006	2005
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
6.000% due 2014	$ 250,000	$ 250,000
5.150% due 2017	125,000	125,000
5.950% due 2035	125,000	125,000
5.100% due 2020	250,000	250,000
5.875% due 2036	150,000	150,000
	900,000	900,000
Pollution control bond series:		
Variable due 2032, 3.65% as of December 31, 2006; 3.30% as of December 31, 2005	45,000	45,000
Variable due 2032, 3.55% as of December 31, 2006; 3.20% as of December 31, 2005	30,500	30,500
5.000% due 2033	58,340	58,340
	133,840	133,840
7.125% unsecured senior notes due 2009	145,078	145,078
	145,078	145,078
KGE		
First mortgage bond series:		
6.200% due 2006	—	100,000
	—	100,000
Pollution control bond series:		
5.100% due 2023	13,488	13,488
Variable due 2027, 3.50% as of December 31, 2006; 3.35% as of December 31, 2005	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
Variable due 2031, 3.47% as of December 31, 2006; 3.49% as of December 31, 2005	100,000	100,000
Variable due 2032, 3.45% as of December 31, 2006; 3.30% as of December 31, 2005	14,500	14,500
Variable due 2032, 3.44% as of December 31, 2006; 3.25% as of December 31, 2005	10,000	10,000
4.85% due 2031	50,000	—
Variable due 2031, 3.85% as of December 31, 2006	50,000	—
	387,428	387,428
Unamortized debt discount[(a)]	(3,081)	(3,356)
Long-term debt due within one year	—	(100,000)
Long-term debt, net	$1,563,265	$1,562,990

[(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. We must comply with such restrictions prior to the issuance of additional first mortgage bonds or other secured indebtedness.

The amount of Westar Energy's first mortgage bonds authorized by its Mortgage and Deed of Trust, dated July 1, 1939, as supplemented, is unlimited subject to certain limitations as described below. The amount of KGE's first mortgage bonds authorized by the KGE Mortgage and Deed of Trust, dated April 1, 1940, as supplemented, is limited to a maximum of $2.0 billion, unless amended. First mortgage bonds are secured by utility assets. Amounts of additional bonds that may be issued are subject to property, earnings and certain restrictive provisions, except in connection with certain refundings, of each mortgage. As of December 31, 2006, based on an assumed interest rate of 6%, $378.8 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage. As of December 31, 2006, based on an assumed interest rate of 6%, approximately $908.1 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

On June 1, 2006, we refinanced $100.0 million of pollution control bonds, which were to mature in 2031. We replaced this issue with two new pollution control bond series of $50.0 million each. One series carries an interest rate of 4.85% and matures in 2031. The second series carries a variable interest rate and also matures in 2031.

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

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain leverage ratios as defined in the agreements. We calculate these ratios in accordance with our credit agreements. We use these ratios solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2006.

Maturities

Maturities of long-term debt as of December 31, 2006 are as follows.

Year	Principal Amount
	(In Thousands)
2007	$ —
2008	—
2009	145,078
2010	—
Thereafter	1,421,268
Total long-term debt maturities	$1,566,346

Our interest expense on long-term debt was $91.0 million in 2006, $107.8 million in 2005 and $141.1 million in 2004.

11. INCOME TAXES

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

Year Ended December 31,	2006	2005	2004
		(In Thousands)	
Income tax expense (benefit) from continuing operations:			
Current income taxes:			
Federal	$46,211	$30,132	$ 41,649
State	14,303	4,829	(2,991)
Deferred income taxes:			
Federal	(1,150)	24,831	(2,285)
State	578	3,511	1,858
Investment tax credit amortization	(3,630)	(2,790)	(4,788)
Income tax expense from continuing operations	56,312	60,513	33,443
Income tax expense (benefit) from discontinued operations:			
Current income taxes:			
Federal	—	29	(116,903)
State	—	7	(22,569)
Deferred income taxes:			
Federal	—	370	77,019
State	—	84	17,172
Income tax expense (benefit) from discontinued operations	—	490	(45,281)
Total income tax expense (benefit)	$56,312	$61,003	$ (11,838)

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

December 31,	2006	2005
	(In Thousands)	
Current deferred tax assets	$ 853	$ 19,211
Non-current deferred tax liabilities	906,311	911,135
Net deferred tax liabilities	$905,458	$891,924

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,	2006	2005
	(In Thousands)	
Deferred tax assets:		
Deferred gain on sale-leaseback	$ 54,978	$ 57,297
General business credit carryforward [a]	—	15,679
Accrued liabilities	30,531	20,390
Disallowed costs	15,955	16,617
Long-term energy contracts	9,314	10,289
Deferred employee benefit costs	77,155	—
Capital loss carryforward [b]	219,795	227,668
Other	74,963	79,547
Total gross deferred tax assets	482,691	427,487
Less: Valuation allowance [b]	223,227	233,211
Deferred tax assets	$ 259,464	$ 194,276
Deferred tax liabilities:		
Accelerated depreciation	$ 642,493	$ 644,082
Acquisition premium	227,999	235,167
Amounts due from customers for future income taxes, net	160,147	166,632
Deferred employee benefit costs	74,111	—
Other	60,172	40,319
Total deferred tax liabilities	$1,164,922	$1,086,200
Net deferred tax liabilities	$ 905,458	$ 891,924

[a] *As of December 31, 2005, we had available general business tax credits of $15.7 million generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These tax credits expire beginning 2019 through 2025. We believe these tax credits will be fully utilized in 2006.*

[b] *As of December 31, 2006, we have a net capital loss of $552.6 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 $219.8 million has been established. In addition, a valuation allowance of $3.4 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 $223.2 million as of December 31, 2006 and $233.2 million as of December 31, 2005. The net reduction in valuation allowance of $10.0 million was due primarily to capital gains realized in 2006.*

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,	2006	2005	2004
Statutory federal income tax rate from continuing operations	35.0 %	35.0 %	35.0 %
Effect of:			
State income taxes	4.4	2.8	1.0
Amortization of investment tax credits	(1.6)	(1.4)	(3.6)
Corporate-owned life insurance policies	(8.3)	(6.9)	(9.0)
Accelerated depreciation flow through and amortization	1.4	1.2	5.3
Income tax reserve adjustment	0.7	0.6	(5.3)
Capital loss utilization	(4.0)	(0.8)	(2.2)
Other	(2.2)	0.5	3.8
Effective income tax rate from continuing operations	25.4 %	31.0 %	25.0%
Statutory federal income tax rate from discontinued operations	— %	35.0 %	35.0 %
Effect of:			
State income taxes	—	4.8	(6.4)
Tax loss in excess of book loss	—	—	(160.6)
Valuation allowance capital loss	—	—	(3.9)
Other	—	—	0.8
Effective income tax rate from discontinued operations	— %	39.8 %	(135.1)%

We file income tax returns in the U.S. and various state jurisdictions. As a matter of course, we remain subject to ongoing federal and state tax examinations. We have extended the federal statute of limitations for years 1995 through 2002 until December 31, 2007.

As of December 31, 2006 and 2005, we recorded reserves for uncertain tax positions of $53.6 million and $50.8 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, 2006 and 2005, we also had a reserve of $6.9 million and $6.1 million, respectively, for probable assessments of taxes other than income taxes.

In July 2006 FASB released FIN 48, which prescribes a comprehensive model for how companies should recognize, measure and disclose in their financial statements uncertain tax positions taken, or expected to be taken, on a tax return. It also provides guidance on derecognizing, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006 with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings.

We will adopt the guidance effective January 1, 2007. As of this date, we continue to evaluate what impact the adoption of FIN 48 will have on our consolidated financial statements. We do not expect the adoption of FIN 48 to have a material impact on our consolidated financial statements.

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 funding policy for the pension plan is to contribute amounts sufficient to meet the minimum funding requirements under the PPA plus additional amounts as considered appropriate. 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. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain current and retired officers.

In addition to providing pension benefits, we provide certain post-retirement health care and life insurance benefits for substantially all retired employees. The cost of post-retirement benefits are accrued during an employee's years of service and recovered through rates. We fund the portion of net periodic post-retirement benefit costs that are included in rates.

As a co-owner of Wolf Creek, we are indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement plans. See Note 13, "Wolf Creek Employee Benefit Plans" for information about Wolf Creek's benefit plans.

In September 2006, FASB released SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans — An Amendment of FASB Statements No. 87, 88, 106, and 132(R)." Under the new standard, companies must recognize a net liability or asset to report the funded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets. On December 31, 2006 we adopted the recognition and disclosure provisions of SFAS No. 158. The effect of adopting SFAS No. 158 on our financial condition at December 31, 2006 has been included in the accompanying consolidated financial statements. We received an accounting authority order from the KCC to recognize as a regulatory asset the pension and post-retirement liabilities that otherwise would have been charged to other comprehensive income. SFAS No. 158 did not have an effect on our consolidated financial condition at December 31, 2005.

The incremental effect of adopting the provisions of SFAS No. 158 on our statement of financial position at December 31, 2006, including the effect on our portion of Wolf Creek's pension and post-retirement plans, are presented in the following table. The adoption of SFAS No. 158 had no effect on our consolidated statement of income for the year ended December 31, 2006, or for any prior period presented.

Incremental Effect of Applying SFAS No. 158 on Individual Line Items in the Consolidated Balance Sheet as of December 31, 2006

	Before SFAS No. 158	Adjustments	After SFAS No. 158
CURRENT ASSETS:			
Regulatory assets	$ —	$ 17,582	$ 17,582
Total Current Assets	—	17,582	17,582
OTHER ASSETS:			
Regulatory assets	—	168,732	168,732
Other	14,412	(14,412)	—
Total Other Assets	14,412	154,320	168,732
TOTAL ASSETS	14,412	171,902	186,314
CURRENT LIABILITIES:			
Other	—	2,467	2,467
Total Current Liabilities	—	2,467	2,467
LONG-TERM LIABILITIES:			
Deferred income taxes	(16,948)	11,466	(5,482)
Accrued employee benefits	71,274	135,999	207,273
Total Long-Term Liabilities	54,326	147,465	201,791
SHAREHOLDERS' EQUITY:			
Accumulated other comprehensive (loss) income, net	(21,970)	21,970	—
Total Shareholders' Equity	(21,970)	21,970	—
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 32,356	$171,902	$204,258

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

As of December 31,	Pension Benefits 2006	Pension Benefits 2005	Post-retirement Benefits 2006	Post-retirement Benefits 2005
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$549,132	$494,615	$128,185	$123,466
Service cost	9,178	6,735	1,492	1,615
Interest cost	30,522	28,764	6,875	7,049
Plan participants' contributions	—	—	3,380	3,380
Benefits paid	(28,345)	(28,581)	(11,306)	(11,825)
Assumption changes	(9,925)	43,264	(2,032)	3,714
Actuarial losses (gains)	1,166	430	(2,048)	279
Amendments	—	3,905	—	507
Benefit obligation, end of year	$551,728	$549,132	$124,546	$128,185
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$422,300	$422,602	$44,196	$32,612
Actual return on plan assets	35,302	26,604	3,374	1,276
Employer contribution	20,750	—	12,200	18,600
Plan participants' contributions	—	—	3,380	3,380
Part D Reimbursements	—	—	677	—
Benefits paid	(26,528)	(26,906)	(11,049)	(11,672)
Fair value of plan assets, end of year	$451,824	$422,300	$52,778	$44,196
Funded status	$(99,904)	$(126,832)	$(71,768)	$(83,989)
Unrecognized net loss	N/A	118,821	N/A	33,757
Unrecognized transition obligation, net	N/A	—	N/A	27,839
Unrecognized prior service cost	N/A	17,051	N/A	(424)
Prepaid benefit (accrued) costs	$(99,904)	$9,040	$(71,768)	$(22,817)
Amounts Recognized in the Balance Sheets Consist Of:				
Current liability	$(1,930)	$N/A	$—	$N/A
Noncurrent liability	(97,974)	N/A	(71,768)	N/A
Prepaid benefit cost	N/A	25,983	N/A	N/A
Accrued benefit liability	N/A	(16,943)	N/A	(22,817)
Additional minimum liability	N/A	(80,758)	N/A	N/A
Intangible asset	N/A	17,051	N/A	N/A
Accumulated other comprehensive income	N/A	63,707	N/A	N/A
Net amount recognized	$(99,904)	$9,040	$(71,768)	$(22,817)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$102,172	$N/A	$26,570	$N/A
Prior service cost	13,926	N/A	17	N/A
Transition obligation	—	N/A	23,909	N/A
Net amount recognized	$116,098	$N/A	$50,496	$N/A

As of December 31,	Pension Benefits 2006	Pension Benefits 2005	Post-retirement Benefits 2006	Post-retirement Benefits 2005
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$551,728	$549,132	$N/A	$N/A
Accumulated benefit obligation	483,511	494,018	N/A	N/A
Fair value of plan assets	451,824	422,300	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$551,728	$549,132	$N/A	$N/A
Accumulated benefit obligation	483,511	494,018	N/A	N/A
Fair value of plan assets	451,824	422,300	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	$124,546	$128,185
Fair value of plan assets	N/A	N/A	52,778	44,196
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.90%	5.65%	5.80%	5.65%
Compensation rate increase	4.00%	3.50%	4.00%	3.50%

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

We use an interest rate yield curve to make judgments pursuant to 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.

We amortize the prior service cost (benefit) on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. 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 No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Post-retirement Benefits Other Than Pensions."

Year Ended December 31,	Pension Benefits 2006	2005	2004
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 9,178	$ 6,735	$ 6,110
Interest cost	30,522	28,764	28,319
Expected return on plan assets	(35,939)	(36,272)	(38,561)
Amortization of unrecognized:			
Transition obligation, net	—	—	—
Prior service costs/(benefit)	2,892	2,761	2,762
Actuarial loss, net	8,759	5,347	2,525
Net periodic cost	$15,412	$ 7,335	$ 1,155
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	5.65%	5.90%	6.10%
Expected long-term return on plan assets	8.50%	8.75%	9.00%
Compensation rate increase	3.50%	3.00%	3.10%

Year Ended December 31,	Post-retirement Benefits 2006	2005	2004
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 1,492	$ 1,615	$ 1,487
Interest cost	6,875	7,049	6,774
Expected return on plan assets	(2,971)	(2,552)	(1,999)
Amortization of unrecognized:			
Transition obligation, net	3,931	3,931	3,931
Prior service costs/(benefit)	(415)	(467)	(467)
Actuarial loss, net	2,001	1,934	1,172
Net periodic cost	$10,913	$11,510	$ 10,898
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	5.65%	5.90%	6.10%
Expected long-term return on plan assets	7.75%	8.25%	8.50%
Compensation rate increase	3.50%	3.00%	3.10%

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2007 are as follows:

	Pension Benefits	Other Post-retirement Benefits
Actuarial loss	$ 7,625	$1,830
Prior service (credit)/cost	2,535	(415)
Transition obligation	—	3,931
Total	$10,160	$5,346

We base the expected long-term rate of return on plan assets on historical and projected rates of return for current and planned asset classes in the plans' investment portfolio. 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 $4.6 million. The subsidy also decreased the net periodic post-retirement benefit cost by approximately $0.6 million for 2006.

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

As of December 31,	2006	2005
Health care cost trend rate assumed for next year	9.00%	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	2011	2009

The health care cost trend rate affects the projected benefit obligation. A 1% change in assumed health care cost growth rates would have effects shown in the following table.

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(In Thousands)	
Effect on total of service and interest cost	$ 56	$ (62)
Effect on post-retirement benefit obligation	852	(943)

The asset allocation for the pension plans and the post-retirement benefit plans at the end of 2006 and 2005, and the target allocations for 2007, by asset category, are as shown in the following table.

Asset Category	Target Allocations 2007	Plan Assets 2006	2005
Pension Plans:			
Equity securities	65%	62%	65%
Debt securities	35%	35%	29%
Cash	0% - 5%	3%	6%
Total		100%	100%
Post-retirement Benefit Plans:			
Equity securities	65%	64%	40%
Debt securities	30%	28%	50%
Cash	5%	8%	10%
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.

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

	Pension Benefits		Post-retirement Benefits	
Expected Cash Flows	To/(From) Trust	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
	(In Millions)			
Expected contributions:				
2007[a]	$ 11.8	$ 1.9	$ 11.4	$ 0.3
Expected benefit payments:				
2007	$ (26.1)	$ (1.9)	$ (8.1)	$ (0.3)
2008	(26.0)	(1.9)	(8.2)	(0.3)
2009	(26.1)	(1.8)	(8.3)	(0.3)
2010	(26.4)	(1.8)	(8.3)	(0.3)
2011	(27.0)	(1.8)	(8.4)	(0.3)
2012 – 2016	(155.7)	(9.0)	(43.5)	(1.5)

[a] *We expect to make a voluntary contribution to the Westar Energy pension trust in 2007. We estimate that amount to be $11.8 million.*

Savings Plans

We maintain a qualified 401(k) savings plan in which most of our employees participate. We match employees' contributions in cash up to specified maximum limits. Our contributions to the plans are deposited with a trustee and are invested at the direction of plan participants into one or more of the investment alternatives we provide under the plan. Our contributions were $4.8 million in 2006, $4.1 million in 2005 and $3.4 million in 2004.

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. 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. As of December 31, 2006, awards of 3,772,823 shares of common stock had been made under the LTISA Plan. Dividend equivalents accrue on the awarded RSUs. Dividend equivalents are the right to receive cash equal to the value of dividends paid on our common stock.

Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), "Share-Based Payment," (SFAS No. 123R) for stock-based compensation plans. Under SFAS No. 123R, all stock-based compensation is measured at the grant date, based on the fair value of the award, and is recognized as an expense in the consolidated statement of income over the requisite service period. On March 29, 2005, the Securities and Exchange Commission (SEC) staff issued Staff Accounting Bulletin (SAB) No. 107 on Share-Based Payment to express the views of the staff regarding the interaction between SFAS No. 123R and SEC rules and regulations as well as provide staff's view on valuation of stock-based compensation arrangements for public companies. The SAB No. 107 guidance was taken into consideration with the implementation of SFAS No. 123R.

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

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

Twelve Months Ended December 31,	2006	2005	2004
		(In Thousands)	
Compensation expense	$ 3,395	$ 4,560	$ 8,141
Income tax benefits related to stock-based compensation arrangements	1,350	1,814	3,238

The incremental amount of stock-based compensation expense that was disclosed and not included in our consolidated statements of income for the years ended December 31, 2005 and 2004 was not material to our consolidated results of operations.

Restricted share unit (RSU) awards are grants that entitle the holder to receive shares of common stock as the awards vest. These RSU awards are defined in SFAS No. 123R as nonvested shares and do not include restrictions once the awards have vested. We measure the fair value of the RSU awards based on the market price of the underlying common stock as of the date of grant and recognize that cost as an expense in the consolidated statement of income over the requisite service period. The requisite service periods range from one to ten years. RSU awards issued after adoption of SFAS No. 123R with only service conditions that have a graded vesting schedule will be recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for the entire award. Awards issued prior to adoption of SFAS No. 123R will continue to be recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for each separately vesting portion of the award.

During the year ended December 31, 2006, our RSU activity was as follows:

As of December 31,	2006		2005		2004	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value
	(In Thousands)		(In Thousands)		(In Thousands)	
Nonvested balance, beginning of year	1,094.5	$18.54	1,298.4	$17.50	1,913.7	$16.25
Granted	160.3	23.91	135.5	22.04	60.1	20.57
Vested	(306.6)	14.96	(336.0)	13.28	(668.4)	14.65
Forfeited	(14.8)	21.56	(3.4)	20.43	(7.0)	17.72
Nonvested balance, end of year	933.4	20.82	1,094.5	18.54	1,298.4	17.50

Total unrecognized compensation cost related to RSU awards was $4.4 million as of December 31, 2006. These costs are expected to be recognized over a remaining weighted-average period of 3.7 years. Upon adoption of SFAS No. 123R, we were required to charge $10.3 million of unearned stock compensation against additional paid-in capital. The total fair value of shares vested during the years ended December 31, 2006, 2005 and 2004, was $7.2 million, $7.5 million and $13.6 million, respectively. There were no modifications of awards during the years ended December 31, 2006, 2005 or 2004.

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

RSU awards that can be settled in cash upon a change in control were reclassified from permanent equity to temporary equity upon adoption of SFAS No. 123R. As of December 31, 2006, we had $6.7 million of temporary equity on our consolidated balance sheet. If we determine it is probable that these awards will be settled in cash, the awards will be reclassified as a liability.

Stock options granted between 1997 and 2001 are completely vested and expire 10 years from the date of grant. All 160,480 outstanding options are exercisable. There were 7,225 options exercised and 51,885 options forfeited during the year ended December 31, 2006. We currently have no plans to issue new stock option awards.

Another component of the LTISA Plan is the Executive Stock for Compensation program, where in the past eligible employees were entitled to receive deferred stock in lieu of current cash compensation. Although this plan was discontinued in 2001, dividends will continue to be paid to plan participants on their outstanding plan balance until distribution. Plan participants were awarded 4,407 shares of common stock for dividends in 2006, 3,936 shares in 2005 and 4,422 shares in 2004. Participants received common stock distributions of 1,936 shares in 2006, 12,271 shares in 2005 and 46,544 shares in 2004.

Prior to the adoption of SFAS No. 123R, we reported all tax benefits resulting from the vesting of RSU awards and exercise of stock options as operating cash flows in the consolidated statements of cash flows. SFAS No. 123R requires cash retained as a result of excess tax benefits resulting from the tax deductions in excess of the related compensation cost recognized in the financial statements to be classified as cash flows from financing activities in the consolidated statements of cash flows.

13. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefits

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

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2006	2005	2006	2005
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 71,537	$ 59,168	$ 7,005	$ 6,102
Service cost	3,245	2,820	248	238
Interest cost	4,293	3,730	412	384
Plan participants' contributions	—	—	253	193
Benefits paid	(1,185)	(992)	(610)	(515)
Actuarial losses	1,278	6,811	83	603
Amendments	45	—	—	—
Benefit obligation, end of year	$ 79,213	$ 71,537	$ 7,391	$ 7,005
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 39,752	$ 32,491	$ N/A	$ N/A
Actual return on plan assets	4,346	2,979	N/A	N/A
Employer contribution	4,766	5,084	N/A	N/A
Benefits paid	(995)	(802)	N/A	N/A
Fair value of plan assets, end of year	$ 47,869	$ 39,752	$ N/A	$ N/A
Funded status	$ (31,344)	$ (31,785)	$ (7,391)	$ (7,005)
Unrecognized net loss	N/A	20,850	N/A	2,645
Unrecognized transition obligation, net	N/A	342	N/A	403
Unrecognized prior service cost	N/A	188	N/A	—
Post-measurement date adjustments	1,164	205	N/A	—
Accrued post-retirement benefit costs	$ (30,180)	$ (10,200)	$ (7,391)	$ (3,957)
Amounts Recognized in the Balance Sheets Consist Of:				
Current liability	$ (190)	$ N/A	$ (347)	$ N/A
Noncurrent liability	(29,990)	N/A	(7,044)	N/A
Accrued benefit liability	N/A	(10,200)	N/A	(3,957)
Additional minimum liability	N/A	(5,144)	N/A	N/A
Intangible asset	N/A	530	N/A	N/A
Accumulated other comprehensive income	N/A	4,614	N/A	N/A
Net amount recognized	$ (30,180)	$ (10,200)	$ (7,391)	$ (3,957)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 19,397	$ N/A	$ 2,531	$ N/A
Prior service cost	202	N/A	—	N/A
Transition obligation	284	N/A	346	N/A
Net amount recognized	$ 19,883	$ N/A	$ 2,877	$ N/A

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2006	2005	2006	2005
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 79,213	$ 71,537	$ N/A	$ N/A
Accumulated benefit obligation	62,339	55,302	N/A	N/A
Fair value of plan assets	47,869	39,752	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 79,213	$ 71,537	$ N/A	$ N/A
Accumulated benefit obligation	62,339	55,302	N/A	N/A
Fair value of plan assets	47,869	39,752	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	$ 7,931	$ 7,005
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	5.70%	5.75%	5.80%	5.75%
Compensation rate increase	3.25%	3.25%	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 uses an interest rate yield curve 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.

Year Ended December 31,	Pension Benefits 2006	2005	2004
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 3,245	$ 2,820	$ 2,572
Interest cost	4,293	3,730	3,295
Expected return on plan assets	(3,428)	(3,114)	(2,780)
Amortization of unrecognized:			
Transition obligation, net	57	57	57
Prior service costs	31	31	31
Actuarial loss, net	1,813	1,340	802
Net periodic cost	$ 6,011	$ 4,864	$ 3,977
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	5.75%	6.00%	6.20%
Expected long-term return on plan assets	8.25%	8.75%	9.00%
Compensation rate increase	3.25%	3.00%	3.20%

Year Ended December 31,	Post-retirement Benefits 2006	2005	2004
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 248	$ 238	$ 235
Interest cost	412	384	356
Expected return on plan assets	—	—	—
Amortization of unrecognized:			
Transition obligation, net	58	58	58
Prior service costs	—	—	—
Actuarial loss, net	196	170	141
Net periodic cost	$ 914	$ 850	$ 790
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	5.75%	6.00%	6.10%
Expected long-term return on plan assets	N/A	N/A	N/A
Compensation rate increase	N/A	N/A	N/A

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2007 are as follows:

	Pension Benefits	Other Post-retirement Benefits
Actuarial loss	$ 1,724	$ 183
Prior service cost	54	—
Transition obligation	57	58
Total	$ 1,835	$ 241

The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing long-term historical experience and future expectations of the volatility of the various asset classes. Based on target asset allocations for each asset class, the overall expected rate of return for the portfolio was developed, adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

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

As of December 31,	2006	2005
Health care cost trend rate assumed for next year	9.0%	8.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2011	2012

The health care cost trend rate affects the projected benefit obligation. A 1% change in assumed health care cost growth rates would have effects shown in the following table.

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(In Thousands)	
Effect on total of service and interest cost	$ 6	$ (6)
Effect on the present value of the projected benefit obligation	42	(42)

The asset allocation for the pension plans at the end of 2006 and 2005, and the target allocation for 2007, by asset category are as shown in the following table.

Asset Category	Target Allocations 2007	Plan Assets 2006	2005
Pension Plans:			
Equity securities	65%	63%	63%
Debt securities	35%	34%	27%
Cash	0%	3%	10%
Total		100%	100%

The Wolf Creek pension plan investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. Investments are diversified across classes, sectors and manager style, to maximize returns and to minimize the risk of large losses. Wolf Creek delegates investment management to specialists in each asset class and where appropriate, provides the investment manager with specific guidelines, which include allowable and/or prohibited investment types. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews.

Expected Cash Flows	Pension Benefits To/(From) Trust	Pension Benefits To/(From) Company Assets	Post-retirement Benefits To/(From) Trust	Post-retirement Benefits To/(From) Company Assets
	(In Millions)			
Expected contributions:				
2007	$ 6.3	$ 0.2	$ N/A	$ 0.3
Expected benefit payments:				
2007	$(1.2)	$(0.2)	$ N/A	$(0.3)
2008	(1.5)	(0.2)	N/A	(0.4)
2009	(1.7)	(0.2)	N/A	(0.4)
2010	(2.0)	(0.2)	N/A	(0.4)
2011	(2.4)	(0.2)	N/A	(0.5)
2012 – 2016	(20.2)	(1.2)	N/A	(3.2)

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 in 2006, $0.9 million in 2005 and $0.8 million in 2004.

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 $352.7 million as of December 31, 2006, of which $176.1 million has been committed. The $176.1 million commitment relates to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments as of December 31, 2006 was as follows.

	Committed Amount
	(In Thousands)
2007	$ 56,441
2008	99,726
2009	13,818
Thereafter	6,135
Total amount committed	$ 176,120

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 (SO_2), particulate matter and nitrogen oxides (NOx). In addition, we must comply with the provisions of the Clean Air Act Amendments of 1990 that require a two-phase reduction in 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 in 2005. We will continue to incur costs through the scheduled completion in 2009. We anticipate that our share of these capital costs will be approximately $232.5 million. Additionally, we have identified the potential for up to $512.4 million of expenditures at other power plants for other environmental projects during approximately the next seven to ten 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. The environmental cost recovery rider (ECRR) approved in the 2005 KCC Order allows for the timely inclusion in rates of capital expenditures tied directly to environmental improvements required by the Clean Air Act. However, increased operating and maintenance costs, other than expenses related to production-related consumables, such as limestone, can be recovered only through a change in base rates following a rate review.

The degree to which we will need to reduce emissions and the timing of when such emissions controls 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. In addition, the availability of equipment and contractors can affect the timing and ultimate cost of equipment installation. Whether through base rates or the ECRR, we expect to recover such costs through the rates we charge our customers.

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 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. 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. We are not able to estimate the possible loss or range of loss at this time.

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. 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.

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.

In 2005, Wolf Creek filed an updated nuclear decommissioning site study with the KCC. Based on the 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 the operating 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. We recovered in rates and deposited in the trust approximately $3.9 million for nuclear decommissioning in 2006 and 2005 and $3.8 million in 2004. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $111.1 million as of December 31, 2006 and $100.8 million as of December 31, 2005.

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 $4.1 million in 2006, $3.8 million in 2005 and $4.3 million in 2004 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 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 $3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), our insurance provider, exists for property claims, including accidental outage power costs for acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within twelve months from the date of the first act. These limits are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. 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, the owners of Wolf Creek Nuclear Operating Corporation can be assessed a total of $100.6 million (our share is $47.3 million), payable at no more than $15.0 million (our share is $7.1 million) per incident per year, per reactor. Both the total and yearly assessment is subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. This assessment also applies in excess of our worker radiation claims insurance. The next scheduled inflation adjustment is scheduled for July 1, 2008. 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 $26.1 million (our share is $12.3 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. As of December 31, 2006, our share of Wolf Creek's nuclear fuel commitments were approximately $75.4 million for uranium concentrates expiring in 2017, $10.6 million for conversion expiring in 2017, $145.6 million for enrichment expiring at various times through 2024 and $53.5 million for fabrication through 2024.

As of December 31, 2006, our coal and coal transportation contract commitments in 2006 dollars under the remaining terms of the contracts were approximately $1.4 billion. The largest contract expires in 2020, with the remaining contracts expiring at various times through 2013.

As of December 31, 2006, our natural gas transportation commitments in 2006 dollars under the remaining terms of the contracts were approximately $32.1 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 was approximately $9.7 million, adjusted for inflation. We recover such costs from prices we charge our customers.

15. ASSET RETIREMENT OBLIGATIONS

Legal Liability

In accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), we have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of an asset retirement obligation is capitalized and depreciated over the remaining life of the asset.

We have recorded asset retirement obligations at fair value for: the estimated cost to decommission Wolf Creek (our 47% share); disposal of asbestos insulating material at our power plants; remediation of ash disposal ponds; and the disposal of polychlorinated biphenyl (PCB) contaminated oil.

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

As of December 31,	2006	2005
	(In Thousands)	
Beginning asset retirement obligations	$ 129,888	$ 87,118
Liabilities incurred	218	—
Liabilities settled	(737)	—
Transition liability	—	6,336
Accretion expense	8,327	21,796
Revision to nuclear decommissioning ARO Liability	(53,504)	14,638
Ending asset retirement obligations	$ 84,192	$ 129,888

In September 2006, Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, filed a request for a 20 year extension of Wolf Creek's operating license with the Nuclear Regulatory Commission (NRC). Currently, the operating license will expire in 2025. We anticipate that the NRC may take up to two years before it rules on the request. The NRC may impose conditions as part of any approval. Based on the experience of other nuclear plant operators, we believe that the NRC will ultimately approve the request. Therefore, we decreased our asset retirement obligation by $53.5 million to reflect the revision in our estimate of the timing of the cash flows that we will incur to satisfy this obligation.

During 2005 we updated our nuclear decommissioning and dismantlement study. Based upon the results of the 2005 study, we revised our estimate of our Wolf Creek asset retirement obligation. Accordingly, in 2005 we increased our asset retirement liability by $14.6 million.

In March 2005, the FASB issued FIN 47. The interpretation clarified the term "conditional asset retirement obligation" as used in SFAS No. 143. Conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. We determined the conditional asset retirement obligations that are within the scope of FIN 47 to include disposal of asbestos insulating material at our power plants, remediation of ash disposal ponds and the disposal of PCB contaminated oil. We adopted the provisions of FIN 47 for the year ended December 31, 2005.

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 operate, as permitted by the state of Kansas, ash landfills at several of our power plants. The ash landfills retirement obligation was determined based upon the date each landfill was originally placed in service.

PCB contaminates are contained within company electrical equipment, primarily transformers. The PCB contaminates retirement obligation was determined based upon the PCB regulations that originally became effective in 1978.

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. 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. As of December 31, 2006 and 2005, we had $13.4 million and $6.9 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 were 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 following effectiveness of the settlement was 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 included the payments related to the settlement of the shareholder derivative lawsuit described below. The settlement became effective on June 21, 2006.

Certain present and former members of our board of directors and officers were 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. This appeal was dismissed on June 21, 2006 and the settlement became effective.

We and certain of our present and former officers and employees were 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 was 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 to be paid by our insurance carrier. The full terms of the proposed settlement are set forth in a Class Action Settlement Agreement dated March 23, 2006 filed with the court. On July 27, 2006, the court issued an order that approved the proposed settlement, approved plaintiffs' attorneys' fees and litigation expenses totaling $2.9 million to be paid from the settlement fund, and directed the parties to consummate the settlement in accordance with the settlement agreement.

After the settlement of these lawsuits became effective in 2006, settlement funds were disbursed and liabilities previously recorded in connection with these settlements as current liabilities were reflected as having been paid.

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 resolution of the criminal charges filed by the United States Attorney's Office against Mr. Wittig and Mr. Lake 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. On January 5, 2007, these convictions were overturned by U.S. Tenth Circuit Court of Appeals following appeals by Mr. Wittig and Mr. Lake. The government is evaluating what action to take as a result of this decision and the arbitration remains stayed. 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 14, 17 and 18 for discussion of 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. Subsequently, the United States Attorney's Office 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 provided information in response to these requests and we cooperated 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."

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. 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 resolution of criminal charges filed by the United States Attorney's Office against Mr. Wittig and Mr. Lake 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. On January 5, 2007, these convictions were overturned by U.S. Tenth Circuit Court of Appeals following appeals by Mr. Wittig and Mr. Lake. The government is evaluating what action to take as a result of this decision and the arbitration remains stayed. We are unable to predict the ultimate impact of this matter on our consolidated results of operations.

As of December 31, 2006, we had accrued liabilities totaling approximately $74.8 million for compensation not yet paid to Mr. Wittig and Mr. Lake under various agreements and plans. The compensation includes RSU awards, deferred vested shares, deferred RSU awards, deferred vested stock for compensation, executive salary continuation plan benefits, potential obligations related to the cash received for Guardian International, Inc. (Guardian) preferred stock as discussed in Note 19, "Guardian International Preferred Stock," 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, through December 31, 2006 we have accrued $9.9 million 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 by Mr. Wittig and Mr. Lake in the defense of the criminal charges filed by the United States Attorney's Office and the subsequent appeal of convictions on these charges. On January 5, 2007, the convictions were overturned by the U.S. Tenth Circuit Court of Appeals. We may incur substantial additional expenses for legal fees and expenses incurred by Mr. Wittig and Mr. Lake depending on the actions taken by the United States Attorney's Office as a result of the decision by the Tenth Circuit Court of Appeals and developments in the arbitration, neither of which we are able to predict at this time. 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 that will be incurred by Mr. Wittig and Mr. Lake for which we may be ultimately responsible.

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. We subsequently filed petitions asserting a superior interest in certain forfeited property. The court subsequently entered final orders of forfeiture awarding us certain property forfeited by Mr. Wittig and Mr. Lake. The property awarded to us consists substantially of compensation and benefits that we were seeking to avoid paying in the arbitration proceeding referenced above. Following appeal, the Tenth Circuit Court of Appeals also overturned the forfeiture orders.

19. GUARDIAN INTERNATIONAL PREFERRED STOCK

On March 6, 2006, 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 recognized a gain of approximately $0.3 million as a result of this transaction. 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 either Mr. Wittig or Mr. Lake, as well as related dividends, and now the cash received for the shares, is disputed and is the subject of the arbitration proceeding with Mr. Wittig and Mr. Lake discussed in Note 16, "Legal Proceedings." These shares were, and now the cash received for the shares are, also part of the property forfeited by Mr. Wittig and Mr. Lake in the criminal proceeding discussed in Note 18, "Potential Liabilities to David C. Wittig and Douglas T. Lake." As a result of this transaction, we no longer hold any Guardian securities.

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."

20. COMMON AND PREFERRED STOCK

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

	Cumulative preferred stock shares	Common stock shares	Treasury stock shares
Balance at December 31, 2003	214,363	72,840,217	(203,575)
Issuance of common stock	—	13,189,504	—
Issuance of treasury stock	—	—	203,575
Balance at December 31, 2004	214,363	86,029,721	—
Issuance of common stock	—	805,650	—
Balance at December 31, 2005	214,363	86,835,371	—
Issuance of common stock	—	559,515	—
Balance at December 31, 2006	214,363	87,394,886	—

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. As of December 31, 2006, we had 87,394,886 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 2006, a total of 559,515 shares were issued by Westar Energy through the DSPP and other stock based plans operated under the 1996 Long-Term Incentive and Share Award Plan. As of December 31, 2006, a total of 4,684,639 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 as of December 31, 2006.

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. As of December 31, 2006, 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 23 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:		
2004	$ 28,895	$ 38,793
2005	23,481	34,239
2006	18,069	32,107
Future commitments:		
2007	$ 23,464	$ 35,272
2008	32,892	45,196
2009	32,964	43,868
2010	33,041	42,622
2011	33,122	42,366
Thereafter	322,683	374,415
Total future commitments	$ 478,166	$ 583,739

[(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 4-year term. Assets recorded under capital leases are listed below.

December 31,	2006	2005
	(In Thousands)	
Vehicles	$30,009	$33,518
Computer equipment and software	4,950	4,168
Accumulated amortization	(18,115)	(19,375)
Total capital leases	$16,844	$18,311

Capital lease payments are currently treated as operating leases for rate making purposes. Minimum annual rental payments, excluding administrative costs such as property taxes, insurance and maintenance, under capital leases are listed below.

Year Ended December 31,	Total Capital Leases
	(In Thousands)
2007	$ 6,162
2008	4,593
2009	3,617
2010	2,425
2011	2,420
Thereafter	2,562
	21,779
Amounts representing imputed interest	(4,935)
Present value of net minimum lease payments under capital leases	$16,844

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

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

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)]
	(In Thousands, Except Per Share Amounts)	
Sales	$ —	$ 22,466
Costs and expenses	—	19,937
Earnings from discontinued operations before income taxes	—	2,529
Estimated gain on disposal	1,232	30,980
Income tax expense (benefit)	490	(45,281)
Results of discontinued operations	$ 742	$ 78,790
Basic results of discontinued operations per share	$ 0.01	$ 0.95
Diluted results of discontinued operations per share	$ 0.01	$ 0.94

[(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.*

23. 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.

Recognition of the change in the market value of our fuel contracts significantly affected our 2005 quarterly results. 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.

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.

2006	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Sales	$340,023	$406,622	$ 515,947	$343,152
Net income	26,838	35,365	90,034	13,073
Earnings available for common stock	$ 26,596	$ 35,123	$ 89,792	$ 12,831
Per Share Data[a]:				
Basic:				
Earnings available	$ 0.30	$ 0.40	$ 1.03	$ 0.15
Diluted:				
Earnings available	$ 0.30	$ 0.40	$ 1.02	$ 0.15
Cash dividend declared per common share	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Market price per common share:				
High	$ 22.05	$ 22.39	$ 24.60	$ 27.24
Low	$ 20.09	$ 20.40	$ 21.50	$ 23.20

[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.*

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.*

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Under the supervision and with the participation of our management, including our chief executive officer and our chief financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934. These controls and procedures are designed to ensure that material information relating to the company and its subsidiaries is communicated to the chief executive officer and the chief financial officer. Based on that evaluation, our chief executive officer and our chief financial officer concluded that, as of December 31, 2006, 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 accumulated and communicated to the chief executive officer and the chief financial officer, and recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

There were no changes in our internal control over financial reporting during the fourth quarter ended December 31, 2006, 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 2007 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (the 2007 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 2007 Proxy Statement, and that information is incorporated by reference in this Form 10-K. The information required by Item 406, 407(c)(3), (d)(4) and (d)(5) of Regulation S-K will be included under the caption "Corporate Governance Matters" in our 2007 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 2007 Proxy Statement under the captions "Compensation Discussion and Analysis," "Compensation Committee Report," "Compensation of Executive Officers and Directors," and "Compensation Committee Interlocks and Insider Participation" and that information is incorporated by reference in this Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 will be set forth in our 2007 Proxy Statement under the captions "Beneficial Ownership of Voting Securities" and "Shares Authorized For Issuance Under Equity Compensation Plans," and that information is incorporated by reference in this Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not applicable.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by Item 14 will be set forth in our 2007 Proxy Statement under the captions "Independent Registered Accounting Firm Fees" and "Audit Committee Pre-Approval Policies and Procedures," and that information is incorporated by reference in this Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

FINANCIAL STATEMENTS INCLUDED HEREIN

Westar Energy, Inc.

Management's Report on Internal Control Over Financial Reporting

Reports of Independent Registered Public Accounting Firm

Consolidated Balance Sheets, as of December 31, 2006 and 2005

Consolidated Statements of Income for the years ended December 31, 2006, 2005 and 2004

Consolidated Statements of Comprehensive Income for the years ended December 31, 2006, 2005 and 2004

Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005 and 2004

Consolidated Statements of Shareholders' Equity for the years ended December 31, 2006, 2005 and 2004

Notes to Consolidated Financial Statements

SCHEDULES

Schedule II – Valuation and Qualifying Accounts

Schedules omitted as not applicable or not required under the Rules of Regulation S-X: I, III, IV, and V

EXHIBIT INDEX

All exhibits marked "I" are incorporated herein by reference. All exhibits marked by an asterisk are management contracts or compensatory plans or arrangements required to be identified by Item 15(a)(3) of Form 10-K. All exhibits marked "#" are filed with this Form 10-K.

Description

1(a)	— Underwriting Agreement between Westar Energy, Inc., and Citigroup Global Markets Inc. and Lehman Brothers Inc., as representatives of the several underwriters, dated January 12, 2005 (filed as Exhibit 1.1 to the Form 8-K filed on January 18, 2005)	I
1(b)	— Underwriting Agreement between Westar Energy, Inc. and Barclays Capital and Citigroup Global Markets, Inc., as representatives of the several underwriters, dated June 27, 2005 (filed as Exhibit 1.1 to the Form 8-K filed on July 1, 2005)	I
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
4(u)	— Forty-Fifth Supplemental Indenture dated March 17, 2006 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee, to the Kansas Gas and Electric Company Mortgage and Deed of Trust dated April 1, 1940 (filed as Exhibit 4.1 to the Form 8-K filed on March 21, 2006)	I
4(v)	— Forty-Sixth Supplemental Indenture dated June 1, 2006 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee, to the Kansas Gas and Electric Company Mortgage and Deed of Trust dated April 1, 1940 (filed as Exhibit 4 to the Form 10-Q for the period ended June 30, 2006 filed on August 9, 2006)	I
	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
10(an) —	Second Amended and Restated Credit Agreement, dated as of March 17, 2006, among Westar Energy, Inc., the several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10.1 to the Form 8-K filed on March 21, 2006)	I
10(ao) —	Amendment to the Employment Letter Agreement for Mr. James S. Haines, Jr. (filed as Exhibit 99.3 to the Form 8-K filed on August 22, 2006)*	I
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
99(i)	—	Federal Energy Regulatory Commission Order On Proposed Mitigation Measures, Tariff Revisions, and Compliance Filings issued September 6, 2006 (filed as Exhibit 99.1 to the Form 8-K filed on September 12, 2006)	I

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, 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
Year ended December 31, 2006				
Allowances deducted from assets for doubtful accounts	$5,233	$5,091	$(4,067)	$6,257

[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 1, 2007

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 and Chief Executive Officer (Principal Executive Officer)	March 1, 2007
/s/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 1, 2007
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	March 1, 2007
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	March 1, 2007
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	March 1, 2007
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	March 1, 2007
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	March 1, 2007
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	March 1, 2007
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	March 1, 2007
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	March 1, 2007
/s/ JOHN C. NETTELS, JR. (John C. Nettels, Jr.)	Director	March 1, 2007

Shareholder Information & Assistance:

Westar Energy's Shareholder Services department offers personalized service to the company's individual shareholders. We are the transfer agent for Westar Energy common and preferred stock. Shareholder Services provides information and assistance to shareholders regarding:

- Dividend payments
  - ➤ Historically paid on the first business day of January, April, July and October
- Direct deposit of dividends
- Transfer of shares
- Lost stock certificate assistance
- Direct Stock Purchase Plan assistance
  - ➤ Dividend reinvestment
  - ➤ Purchase additional shares by making optional cash payments by check or monthly electronic withdrawal from your bank account
  - ➤ Deposit your stock certificates into the plan for safekeeping
  - ➤ Sell shares

Please contact us in writing to request elimination of duplicate mailings because of stock registered in more than one way. Mailing of annual reports can be eliminated by marking your proxy card to consent to accessing reports electronically on the Internet.

Please visit our Web site at **www.WestarEnergy.com.** Registered shareholders can easily access their shareholder account information online by clicking on the **Go to Shareholder Sign-in button.**

CONTACTING SHAREHOLDER SERVICES

TELEPHONE

Toll-free:	(800) 527-2495
In the Topeka area:	(785) 575-6394
Fax:	(785) 575-1796

ADDRESS

Westar Energy, Inc.
Shareholder Services
P.O. Box 750320
Topeka, KS 66675-0320

E-MAIL ADDRESS

shareholders@WestarEnergy.com

Please include a daytime telephone number in all correspondence.

CO-TRANSFER AGENT

Continental Stock Transfer
& Trust Company
17 Battery Place, 8th Floor
New York, NY 10004

CONTACTING INVESTOR RELATIONS

TELEPHONE: (785) 575-8227

ADDRESS

Westar Energy, Inc.
Investor Relations
P.O. Box 889
Topeka, KS 66601-0889

E-MAIL ADDRESS: ir@WestarEnergy.com

Copies of our Annual Report on Form 10-K filed with the Securities and Exchange Commission and other published reports can be obtained without charge by contacting Investor Relations at the above address, by accessing the company's home page on the Internet at www.WestarEnergy.com or by accessing the Securities and Exchange Commission's Internet Web site at www.sec.gov.

TRUSTEE FOR FIRST MORTGAGE BONDS

PRINCIPAL TRUSTEE, PAYING AGENT AND REGISTRAR

The Bank of New York
2 North LaSalle Street, Suite 1020
Chicago, IL 60602-3802
(800) 548-5075

CORPORATE INFORMATION

CORPORATE ADDRESS

Westar Energy, Inc.
818 South Kansas Avenue
Topeka, KS 66612-1203
(785) 575-6300
www.WestarEnergy.com

COMMON STOCK LISTING

Ticker Symbol (NYSE): WR

Daily Stock Table Listing:
WestarEngy

CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER CERTIFICATIONS

In 2006, our chief executive officer submitted a certificate to the New York Stock Exchange (NYSE) affirming that he is not aware of any violation by the company of the NYSE's corporate governance listing standards. Our chief executive officer's and chief financial officer's certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 for the year ended December 31, 2006 were included as exhibits to Westar Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2006 that was filed with the Securities and Exchange Commission.

This report was printed on recycled paper using soy-based inks.

Directors:

Westar Energy Board of Directors, from left, is composed of B. Anthony Isaac, James S. Haines Jr., Arthur B. Krause, Sandra A.J. Lawrence, John C. Nettels Jr., R.A. Edwards III, Mollie Hale Carter, Michael F. Morrissey, Charles Q. Chandler IV and Jerry B. Farley.

CHARLES Q. CHANDLER IV (53)
Chairman of the Board
Director since 1999
Chairman since 2002
Chairman of the Board, President and Chief Executive Officer
INTRUST Bank, NA
Wichita, Kansas

MOLLIE HALE CARTER (44)
Director since 2003
Chairman of the Board, President and Chief Executive Officer
Sunflower Banks, Inc.
Salina, Kansas
Committees: Compensation, Finance

R.A. EDWARDS III (61)
Director since 2001
Director, President and Chief Executive Officer
First National Bank of Hutchinson
Hutchinson, Kansas
Committees: Audit, Nominating and Corporate Governance

JERRY B. FARLEY (60)
Director since 2004
President
Washburn University
Topeka, Kansas
Committees: Audit, Nominating and Corporate Governance

JAMES S. HAINES, JR. (60)
Director since 2002
Chief Executive Officer
Westar Energy, Inc.
Topeka, Kansas

B. ANTHONY ISAAC (53)
Director since 2003
President
LodgeWorks, Corp.
Wichita, Kansas
Committees: Compensation, Finance

ARTHUR B. KRAUSE (65)
Director since 2003
Executive Vice President and Chief Financial Officer (Retired)
Sprint Corporation
Naples, Florida
Committees: Audit, Finance

SANDRA A.J. LAWRENCE (49)
Director since 2004
Executive Vice President and Chief Financial Officer
Children's Mercy Hospital
Kansas City, Missouri
Committees: Compensation, Nominating and Corporate Governance

MICHAEL F. MORRISSEY (64)
Director since 2003
Managing Partner (Retired)
Ernst & Young LLP
Naples, Florida
Committees: Audit, Compensation

JOHN C. NETTELS, JR. (50)
Director since 2000
Partner
Stinson Morrison Hecker LLP
Overland Park, Kansas
Committee: Finance

Ages and years of service are as of December 31, 2006.

Officers:

JAMES S. HAINES, JR. (60)
20 years of service
Chief Executive Officer

WILLIAM B. MOORE (54)
26 years of service
President and Chief Operating Officer

MARK A. RUELLE (45)
14 years of service
Executive Vice President and Chief Financial Officer

DOUGLAS R. STERBENZ (43)
9 years of service
Executive Vice President, Generation and Marketing

BRUCE A. AKIN (42)
19 years of service
Vice President, Administrative Services

GREG A. GREENWOOD (41)
13 years of service
Vice President, Generation Construction

KELLY B. HARRISON (48)
25 years of service
Vice President, Transmission Operations and Environmental Services

LARRY D. IRICK (50)
7 years of service
Vice President, General Counsel and Corporate Secretary

KENNETH C. JOHNSON (53)
5 years of service
Vice President, Generation

PEGGY S. LOYD (49)
28 years of service
Vice President, Customer Care

JAMES J. LUDWIG (48)
16 years of service
Vice President, Regulatory and Public Affairs

ANTHONY D. SOMMA (43)
12 years of service
Treasurer

LEE WAGES (58)
29 years of service
Vice President, Controller

CAROLINE A. WILLIAMS (50)
31 years of service
Vice President, Distribution Power Delivery

Westar Energy®

P.O. Box 889, Topeka, Kansas 66601-0889
www.WestarEnergy.com