WESTAR ENERGY INC /KS
Form 10-Q
November 03, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2011 September 30, 2011

OR

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

For the transition period from _____ to _____

Commission File Number 1-3523

WESTAR ENERGY, INC.

(Exact name of registrant as specified in its charter)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).   Yes x   No ¨

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

Large accelerated filer x   Accelerated filer ¨   Non-accelerated filer ¨   Smaller reporting company ¨

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

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	**117,180,729 shares**
(Class)	**(Outstanding at October 26, 2011)**

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GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
2010 Form 10-K	Annual Report on Form 10-K for the year ended December 31, 2010
AFUDC	Allowance for Funds Used During Construction
BACT	Best available control technology
CSAPR	Cross-State Air Pollution Rule
ECRR	Environmental Cost Recovery Rider
EPA	Environmental Protection Agency
EPS	Earnings per share
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gas
JEC	Jeffrey Energy Center
KCC	Kansas Corporation Commission
KCPL	Kansas City Power & Light Company
KDHE	Kansas Department of Health and Environment
KGE	Kansas Gas and Electric Company
La Cygne	La Cygne Generating Station
MMBtu	Millions of British Thermal Units
Moody s	Moody s Investors Service
MW	Megawatts
MWh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NOx	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
ONEOK	ONEOK, Inc.
OTC	Over-the-counter
PSD	Prevention of Significant Deterioration program
RSUs	Restricted share units
S&P	Standard & Poor s Ratings Services
SCR	Selective catalytic reduction
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
VIE	Variable interest entity
Wolf Creek	Wolf Creek Generating Station

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FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Form 10-Q are forward-looking statements. The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we believe, anticipate, target, expect, estimate, intend and words of similar meaning. Forward-looking statements describe our future plans, objectives, expectations or goals. Such statements address future events and conditions concerning matters such as, but not limited to:

- amount, type and timing of capital expenditures,
- earnings,
- cash flow,
- liquidity and capital resources,
- litigation,
- accounting matters,
- possible corporate restructurings, acquisitions and dispositions,
- compliance with debt and other restrictive covenants,
- interest rates and dividends,
- environmental matters,
- regulatory matters,
- nuclear operations, and
- the overall economy of our service area and its impact on our customers demand for electricity and their ability to pay for service.

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

the risk of operating in a heavily regulated industry subject to frequent and uncertain political, legislative, judicial and regulatory developments at any level of government that can affect our revenues and costs,

weather conditions and their effect on sales of electricity as well as on prices of energy commodities,

equipment damage from storms and extreme weather,

economic and capital market conditions, including the impact of inflation or deflation, changes in interest rates, the cost and availability of capital and the market for trading wholesale energy,

the impact of changes in market conditions on employee benefit liability calculations, as well as actual and assumed investment returns on invested plan assets,

the impact of changes in estimates regarding our Wolf Creek Generating Station (Wolf Creek) decommissioning obligation,

the ability of our counterparties to make payments as and when due and to perform as required,

the existence of or introduction of competition into markets in which we operate,

the impact of frequently changing laws and regulations relating to air emissions, water emissions, waste management and other environmental matters,

risks associated with execution of our planned capital expenditure program, including timing and receipt of regulatory approvals necessary for planned construction and expansion projects as well as the ability to complete planned construction projects within the terms and time frames anticipated,

cost, availability and timely provision of equipment, supplies, labor and fuel we need to operate our business,

availability of generating capacity and the performance of our generating plants,

changes in regulation of nuclear generating facilities and nuclear materials and fuel, including possible shutdown or required modification of nuclear generating facilities,

additional regulation due to Nuclear Regulatory Commission (NRC) oversight to ensure the safe operation of Wolf Creek, either related to Wolf Creek s performance, or potentially relating to events or performance at a nuclear plant anywhere in the world,

uncertainty regarding the establishment of interim or permanent sites for spent nuclear fuel storage and disposal,

homeland and information security considerations, wholesale electricity prices,

changes in accounting requirements and other accounting matters, changes in the energy markets in which we participate resulting from the development and implementation of real time and next day trading markets, and the effect of the retroactive repricing of transactions in such markets following execution because of changes or adjustments in market pricing mechanisms by regional transmission organizations and independent system operators,

reduced demand for coal-based energy because of potential climate impacts and development of alternate energy sources,

current and future litigation, regulatory investigations, proceedings or inquiries,

other circumstances affecting anticipated operations, electricity sales and costs, and

other factors discussed elsewhere in this report and in our Annual Report on Form 10-K for the year ended December 31, 2010 (2010 Form 10-K), including in Item 1A. Risk Factors and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, and in other reports we file from time to time with the Securities and Exchange Commission.

These lists are not all-inclusive because it is not possible to predict all factors. This report should be read in its entirety and in conjunction with our 2010 Form 10-K. No one section of this report deals with all aspects of the subject matter and additional information on some matters that could impact our consolidated financial results may be included in our 2010 Form 10-K. The reader should not place undue reliance on any forward-looking statement, as forward-looking statements speak only as of the date such statements were made. We undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made.

PART I. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

WESTAR ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

(Dollars in Thousands, Except Par Values)

(Unaudited)

	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4,593	$ 928
Accounts receivable, net of allowance for doubtful accounts of $5,325 and $5,729, respectively	252,045	227,700
Inventories and supplies	209,279	206,867
Energy marketing contracts	6,120	13,005
Taxes receivable		16,679
Deferred tax assets		30,248
Prepaid expenses	11,889	12,413
Regulatory assets	107,740	73,480
Other	13,246	20,289
Total Current Assets	604,912	601,609
PROPERTY, PLANT AND EQUIPMENT, NET	6,281,623	5,964,439
PROPERTY, PLANT AND EQUIPMENT OF VARIABLE INTEREST ENTITIES, NET	336,373	345,037
OTHER ASSETS:		
Regulatory assets	800,749	787,585
Nuclear decommissioning trust	121,050	126,990
Energy marketing contracts	7,464	9,472
Other	237,732	244,506
Total Other Assets	1,166,995	1,168,553
TOTAL ASSETS	$ 8,389,903	$ 8,079,638
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$	$ 61
Current maturities of long-term debt of variable interest entities	28,091	30,155
Short-term debt	391,900	226,700
Accounts payable	152,465	187,954
Accrued taxes	66,849	45,534
Energy marketing contracts	3,031	9,670
Accrued interest	68,188	77,771
Regulatory liabilities	33,428	28,284

Other	143,891	176,717
Total Current Liabilities	887,843	782,846
LONG-TERM LIABILITIES:		
Long-term debt, net	2,490,972	2,490,871
Long-term debt of variable interest entities, net	250,632	278,162
Deferred income taxes	1,111,301	1,102,625
Unamortized investment tax credits	155,213	101,345
Regulatory liabilities	130,927	135,754
Deferred regulatory gain from sale-leaseback	93,420	97,541
Accrued employee benefits	433,664	483,769
Asset retirement obligations	131,198	125,999
Energy marketing contracts		10
Other	87,065	66,878
Total Long-Term Liabilities	4,884,392	4,882,954
COMMITMENTS AND CONTINGENCIES (See Notes 8 and 9)		
TEMPORARY EQUITY		3,465
EQUITY:		
Westar Energy Shareholders Equity:		
Cumulative preferred stock, par value $100 per share; authorized 600,000 shares; issued and outstanding 214,363 shares	21,436	21,436
Common stock, par value $5 per share; authorized 275,000,000 shares and 150,000,000 shares, respectively; issued and outstanding 117,083,763 shares and 112,128,068 shares, respectively	585,419	560,640
Paid-in capital	1,480,081	1,398,580
Retained earnings	522,366	423,647
Total Westar Energy Shareholders Equity	2,609,302	2,404,303
Noncontrolling Interests	8,366	6,070
Total Equity	2,617,668	2,410,373
TOTAL LIABILITIES AND EQUITY	$ 8,389,903	$ 8,079,638

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

WESTAR ENERGY, INC.

CONSOLIDATED STATEMENTS OF INCOME

(Dollars in Thousands, Except Per Share Amounts)

(Unaudited)

	Three Months Ended September 30,	
	2011	**2010**
REVENUES	$ 678,152	$ 644,437
OPERATING EXPENSES:		
Fuel and purchased power	199,540	187,877
Operating and maintenance	137,823	126,602
Depreciation and amortization	72,202	67,918
Selling, general and administrative	27,499	50,418
Total Operating Expenses	437,064	432,815
INCOME FROM OPERATIONS	241,088	211,622
OTHER INCOME (EXPENSE):		
Investment earnings	2,914	3,248
Other income	3,404	1,897
Other expense	(5,470)	(5,146)
Total Other Income (Expense)	848	(1)
Interest expense	43,844	43,956
INCOME BEFORE INCOME TAXES	198,092	167,665
Income tax expense	61,700	51,802
NET INCOME	136,392	115,863
Less: Net income attributable to noncontrolling interests	1,442	1,119
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY	134,950	114,744
Preferred dividends	242	242
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 134,708	$ 114,502
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY (See Note 2):		
Basic earnings per common share	$ 1.15	$ 1.02
Diluted earnings per common share	$ 1.14	$ 1.01
Average equivalent common shares outstanding	116,806,596	111,706,541
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.32	$ 0.31

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

WESTAR ENERGY, INC.

CONSOLIDATED STATEMENTS OF INCOME

(Dollars in Thousands, Except Per Share Amounts)

(Unaudited)

	Nine Months Ended September 30,	
	2011	2010
REVENUES	$ 1,684,763	$ 1,599,448
OPERATING EXPENSES:		
Fuel and purchased power	486,697	458,793
Operating and maintenance	412,429	369,584
Depreciation and amortization	213,551	201,955
Selling, general and administrative	132,233	144,499
Total Operating Expenses	1,244,910	1,174,831
INCOME FROM OPERATIONS	439,853	424,617
OTHER INCOME (EXPENSE):		
Investment earnings	6,255	4,350
Other income	8,210	3,792
Other expense	(13,951)	(12,043)
Total Other Income (Expense)	514	(3,901)
Interest expense	130,681	131,862
INCOME BEFORE INCOME TAXES	309,686	288,854
Income tax expense	94,812	86,780
NET INCOME	214,874	202,074
Less: Net income attributable to noncontrolling interests	4,212	3,338
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY	210,662	198,736
Preferred dividends	727	727
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 209,935	$ 198,009
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY (See Note 2):		
Basic earnings per common share	$ 1.82	$ 1.77
Diluted earnings per common share	$ 1.79	$ 1.76
Average equivalent common shares outstanding	115,208,965	111,387,165
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.96	$ 0.93

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

WESTAR ENERGY, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in Thousands)

(Unaudited)

	Nine Months Ended September 30,	
	2011	2010
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:		
Net income	$ 214,874	$ 202,074
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	213,551	201,955
Amortization of nuclear fuel	13,411	19,657
Amortization of deferred regulatory gain from sale-leaseback	(4,121)	(4,121)
Amortization of corporate-owned life insurance	19,137	15,286
Non-cash compensation	6,834	8,280
Net changes in energy marketing assets and liabilities	956	(947)
Accrued liability to certain former officers	1,180	1,959
Net deferred income taxes and credits	100,130	104,133
Stock-based compensation excess tax benefits	(1,186)	(526)
Allowance for equity funds used during construction	(4,448)	(1,926)
Gain on sale of non-utility investment	(7,246)	
Gain on settlement of contractual obligations with former officers	(22,039)	
Changes in working capital items:		
Accounts receivable	(27,269)	(44,207)
Inventories and supplies	(1,837)	(7,298)
Prepaid expenses and other	(36,459)	23,843
Accounts payable	(14,077)	12,965
Accrued taxes	38,291	70,263
Other current liabilities	(105,657)	(84,095)
Changes in other assets	(15,291)	25,984
Changes in other liabilities	(30,957)	(42,912)
Cash Flows from Operating Activities	337,777	500,367
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:		
Additions to property, plant and equipment	(512,675)	(369,746)
Purchase of securities within trusts	(41,118)	(189,784)
Sale of securities within trusts	39,789	189,343
Investment in corporate-owned life insurance	(19,214)	(18,884)
Proceeds from investment in corporate-owned life insurance	869	1,918
Proceeds from federal grant	7,367	
Investment in affiliated company	(1,479)	
Proceeds from sale of non-utility investment	7,246	
Other investing activities	470	(1,760)
Cash Flows used in Investing Activities	(518,745)	(388,913)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:		
Short-term debt, net	159,770	(79,720)
Retirements of long-term debt	(371)	(1,353)

Retirements of long-term debt of variable interest entities	(29,019)	(27,536)
Repayment of capital leases	(1,645)	(1,640)
Borrowings against cash surrender value of corporate-owned life insurance	65,853	72,286
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(3,108)	(3,219)
Stock-based compensation excess tax benefits	1,186	526
Issuance of common stock	96,508	28,299
Distributions to shareholders of noncontrolling interests	(1,916)	(2,094)
Cash dividends paid	(102,625)	(96,391)
Cash Flows from (used in) Financing Activities	184,633	(110,842)
NET INCREASE IN CASH AND CASH EQUIVALENTS	3,665	612
CASH AND CASH EQUIVALENTS:		
Beginning of period	928	3,860
End of period	$ 4,593	$ 4,472

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

WESTAR ENERGY, INC.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Dollars in Thousands)

(Unaudited)

			Westar Energy Shareholders					
	Cumulative	Cumulative						
	preferred stock shares	preferred stock	Common stock shares	Common stock	Paid-in capital	Retained earnings	Noncontrolling interests	Total equity
Balance at December 31, 2009	214,363	$ 21,436	109,072,000	$ 545,360	$ 1,339,790	$ 360,199	$	$ 2,266,785
Net income						198,736	3,338	202,074
Issuance of common stock			1,761,975	8,810	28,698			37,508
Preferred dividends						(727)		(727)
Dividends on common stock						(104,316)		(104,316)
Transfer to temporary equity					(16)			(16)
Amortization of restricted stock					7,667			7,667
Stock compensation and tax benefit					(2,842)			(2,842)
Consolidation of noncontrolling interests							3,435	3,435
Distributions to shareholders of noncontrolling interests							(2,091)	(2,091)
Balance at September 30, 2010	214,363	$ 21,436	110,833,975	$ 554,170	$ 1,373,297	$ 453,892	$ 4,682	$ 2,407,477
Balance at December 31, 2010	214,363	$ 21,436	112,128,068	$ 560,640	$ 1,398,580	$ 423,647	$ 6,070	$ 2,410,373
Net income						210,662	4,212	214,874
Issuance of common stock			4,955,695	24,779	85,532			110,311
Preferred dividends						(727)		(727)
Dividends on common stock						(111,216)		(111,216)
Transfer from temporary equity					3,465			3,465
Amortization of restricted stock					6,176			6,176
Stock compensation and tax benefit					(13,672)			(13,672)
Distributions to shareholders of noncontrolling interests							(1,916)	(1,916)
Balance at September 30, 2011	214,363	$ 21,436	117,083,763	$ 585,419	$ 1,480,081	$ 522,366	$ 8,366	$ 2,617,668

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

WESTAR ENERGY, INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. DESCRIPTION OF BUSINESS

We are the largest electric utility in Kansas. Unless the context otherwise indicates, all references in this Quarterly Report on Form 10-Q 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 687,000 customers in Kansas. Westar Energy provides these services in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric Company (KGE), Westar Energy s wholly owned subsidiary, provides these services in south-central and southeastern Kansas, including the city of Wichita. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

We prepare our unaudited condensed consolidated financial statements in accordance with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, certain information and footnote disclosures normally included in financial statements presented in accordance with generally accepted accounting principles (GAAP) have been condensed or omitted. Our condensed consolidated financial statements include all operating divisions, majority owned subsidiaries and variable interest entities (VIEs) of which we maintain a controlling interest or are the primary beneficiary reported as a single operating segment. Intercompany accounts and transactions have been eliminated in consolidation. In our opinion, all adjustments, consisting only of normal recurring adjustments considered necessary for a fair presentation of the consolidated financial statements, have been included.

The accompanying condensed consolidated financial statements and notes should be read in conjunction with the consolidated financial statements and notes included in our 2010 Form 10-K.

Use of Management s Estimates

When we prepare our condensed 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 condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an on-going basis, including those related to valuation of commodity contracts, depreciation, unbilled revenue, valuation of investments, valuation of our energy marketing portfolio, forecasted fuel costs included in our retail energy cost adjustment billed to customers, income taxes, pension and post-retirement benefits, our asset retirement obligations including the decommissioning of Wolf Creek, environmental issues, VIEs, contingencies and litigation. Actual results may differ from those estimates under different assumptions or conditions. The results of operations for the three and nine months ended September 30, 2011, are not necessarily indicative of the results to be expected for the full year.

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Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the allowed cost of capital used to finance utility construction activity. We compute AFUDC by applying a composite rate to qualified construction work in progress. We credit other income (for equity funds) and interest expense (for borrowed funds) for the amount of AFUDC capitalized as construction cost on the accompanying consolidated statements of income as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Dollars in Thousands)			
Borrowed funds	$ 1,163	$ 1,133	$ 4,224	$ 2,825
Equity funds	1,027	841	4,448	1,926
Total	$ 2,190	$ 1,974	$ 8,672	$ 4,751
Average AFUDC rates	3.2%	2.7%	4.0%	2.4%

Earnings Per Share

We have participating securities in the form of unvested restricted share units (RSUs) with nonforfeitable rights to dividend equivalents that receive dividends as declared on an equal basis with common shares. As a result, we apply the two-class method of computing basic and diluted earnings per share (EPS).

Under the two-class method, we reduce net income attributable to common stock by the amount of dividends declared in the current period. We allocate the remaining earnings to common stock and RSUs to the extent that each security may share in earnings as if all of the earnings for the period had been distributed. We determine the total earnings allocated to each security by adding together the amount allocated for dividends and the amount allocated for a participation feature. To compute basic EPS, we divide the earnings allocated to common stock by the weighted average equivalent common shares outstanding. Diluted EPS includes the effect of potential issuances of common shares resulting from our forward sale agreements, RSUs with forfeitable rights to dividend equivalents and stock options. We compute the dilutive effect of potential issuances of common shares using the treasury stock method.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Dollars In Thousands, Except Per Share Amounts)			
Net income	$ 136,392	$ 115,863	$ 214,874	$ 202,074
Less: Net income attributable to noncontrolling interests	1,442	1,119	4,212	3,338
Net income attributable to Westar Energy	134,950	114,744	210,662	198,736
Less: Preferred dividends	242	242	727	727
Net income allocated to RSUs	440	629	617	1,067
Net income allocated to common stock	$ 134,268	$ 113,873	$ 209,318	$ 196,942
Weighted average equivalent common shares outstanding basic	116,806,596	111,706,541	115,208,965	111,387,165
Effect of dilutive securities:				
RSUs	203,401	200,480	171,003	155,903
Forward sale agreements	1,228,273	408,393	1,585,107	110,519
Employee stock options				74
Weighted average equivalent common shares outstanding diluted (a)	118,238,270	112,315,414	116,965,075	111,653,661
Earnings per common share, basic	$ 1.15	$ 1.02	$ 1.82	$ 1.77
Earnings per common share, diluted	$ 1.14	$ 1.01	$ 1.79	$ 1.76

(a) For the three and nine months ended September 30, 2011 and 2010, we did not have any antidilutive shares.

Supplemental Cash Flow Information

	Nine Months Ended September 30,	
	2011	2010
	(In Thousands)	
CASH PAID FOR (RECEIVED FROM):		
Interest on financing activities, net of amount capitalized	$ 101,146	$ 101,941
Interest on financing activities of VIEs	17,954	19,843
Income taxes, net of refunds	(16,097)	(38,017)
NON-CASH INVESTING TRANSACTIONS:		
Property, plant and equipment additions	86,644	30,443
Property, plant and equipment additions of VIEs		356,964
Jeffrey Energy Center (JEC) 8% leasehold interest		(108,706)
NON-CASH FINANCING TRANSACTIONS:		
Issuance of common stock for reinvested dividends and compensation plans	8,587	13,492
Debt of VIEs		337,951
Capital lease for JEC 8% leasehold interest		(106,423)
Assets acquired through capital leases	43,199	321

Investment Earnings - Sale of Non-utility Investment

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

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

Values of Financial and Derivative Instruments

GAAP establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring assets and liabilities at fair value. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy levels. The three levels of the hierarchy and examples are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities. The types of assets and liabilities included in level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed on public exchanges and exchange-traded futures contracts.

Level 2 Pricing inputs are not quoted prices in active markets, but are either directly or indirectly observable. The types of assets and liabilities included in level 2 are typically measured at net asset value, comparable to actively traded securities or contracts, such as Treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 Significant inputs to pricing have little or no transparency. The types of assets and liabilities included in level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value of options, real estate investments and long-term electricity supply contracts.

We record cash and cash equivalents, short-term borrowings and variable rate debt on our consolidated balance sheets at cost, which approximates fair value. We measure the fair value of fixed rate debt based on quoted market prices for the same or similar issues or on the current rates offered for instruments of the same remaining maturities and redemption provisions. The recorded amount of accounts receivable and other current financial instruments approximates fair value.

All of our level 2 investments, whether in the nuclear decommissioning trust (NDT) or our trading securities portfolio, are held in investment funds that are measured using daily net asset values as reported by the fund managers. In addition, we maintain certain level 3 investments in private equity and real estate securities that require significant unobservable market information to measure the fair value of the investments. The fair value of private equity investments is measured by utilizing both market- and income-based models, public company comparables, at cost or at the value derived from subsequent financings. Adjustments are made when actual performance differs from expected performance; when market, economic or company-specific conditions change; and when other news or events have a material impact on the security. To measure the fair value of real estate securities we use a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity.

Energy marketing contracts can be exchange-traded or traded over-the-counter (OTC). Fair value measurements of exchange-traded contracts typically utilize quoted prices in active markets. OTC contracts are valued using market transactions and other market evidence whenever possible, including market-based inputs to models, model calibration to market clearing transactions or alternative pricing sources with reasonable levels of price transparency. Valuation models require a variety of inputs, including contractual terms, market prices, yield curves, credit curves, nonperformance risk, measures of volatility and correlations of such inputs. Certain OTC contracts trade in less liquid markets with limited pricing information and the determination of fair value for these derivatives is inherently more subjective. In these situations, estimates by management are a significant input. See Recurring Fair Value Measurements and Derivative Instruments below for additional information.

We measure fair value based on information available as of the measurement date. The following table provides the carrying values and measured fair values of our financial instruments as of September 30, 2011, and December 31, 2010.

	As of September 30, 2011		As of December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In Thousands)			
Fixed rate debt	$ 2,373,063	$ 2,605,760	$ 2,373,373	$ 2,570,648
Fixed rate debt of VIEs	276,877	292,235	308,317	341,328

Recurring Fair Value Measurements

The following table provides the amounts and their corresponding level of hierarchy for our assets and liabilities that are measured at fair value.

	Level 1	Level 2	Level 3	Total
		(In Thousands)		
As of September 30, 2011				
Assets:				
Energy Marketing Contracts	$	$ 2,608	$ 10,976	$ 13,584
Nuclear Decommissioning Trust:				
Domestic equity		45,475	3,581	49,056
International equity		21,842		21,842
Core bonds		22,440		22,440
High-yield bonds		8,577		8,577
Emerging market bonds		4,975		4,975
Combination debt/equity fund		7,277		7,277
Real estate securities			6,836	6,836
Cash equivalents	47			47
Total Nuclear Decommissioning Trust	47	110,586	10,417	121,050
Trading Securities:				
Domestic equity		18,873		18,873
International equity		4,648		4,648
Core bonds		13,743		13,743
Total Trading Securities		37,264		37,264
Total Assets Measured at Fair Value	$ 47	$ 150,458	$ 21,393	$ 171,898
Liabilities:				
Energy Marketing Contracts	$	$ 2,462	$ 569	$ 3,031
Treasury Yield Hedges		31,307		31,307
Total Liabilities Measured at Fair Value	$	$ 33,769	$ 569	$ 34,338
As of December 31, 2010				
Assets:				
Energy Marketing Contracts	$ 2,432	$ 6,258	$ 13,787	$ 22,477
Nuclear Decommissioning Trust:				
Domestic equity		60,586	2,867	63,453
International equity		18,966		18,966
Core bonds		31,906		31,906
High-yield bonds		9,267	305	9,572
Real estate securities			3,049	3,049
Cash equivalents	44			44
Total Nuclear Decommissioning Trust	44	120,725	6,221	126,990
Trading Securities:				
Domestic equity		21,207		21,207
International equity		5,128		5,128
Core bonds		13,077		13,077

Total Trading Securities		39,412		39,412
Treasury Yield Hedges		7,711		7,711
Total Assets Measured at Fair Value	$ 2,476	$ 174,106	$ 20,008	$ 196,590
Liabilities:				
Energy Marketing Contracts	$ 1,888	$ 5,820	$ 1,972	$ 9,680

We do not offset the fair value of energy marketing contracts executed with the same counterparty. As of September 30, 2011, we had recorded no right to reclaim cash collateral and $0.4 million for our obligation to return cash collateral. As of December 31, 2010, we had no right to reclaim cash collateral and had recorded $0.7 million for our obligation to return cash collateral.

The following table provides reconciliations of assets and liabilities measured at fair value using significant level 3 inputs for the three and nine months ended September 30, 2011.

		Nuclear Decommissioning Trust			
	Energy Marketing Contracts, net	Domestic Equity	High-yield Bonds	Real Estate Securities	Net Balance
			(In Thousands)		
Balance as of June 30, 2011	$ 10,893	$ 3,111	$	$ 3,296	$ 17,300
Total realized and unrealized gains (losses) included in:					
Earnings (a)	(886)				(886)
Regulatory assets	(375)(b)				(375)
Regulatory liabilities	1,267(b)	330		164	1,761
Purchases	(2,235)	140		3,432	1,337
Sales	1,808			(56)	1,752
Settlements	(65)				(65)
Balance as of September 30, 2011	$ 10,407	$ 3,581	$	$ 6,836	$ 20,824
Balance as of December 31, 2010	$ 11,815	$ 2,867	$ 305	$ 3,049	$ 18,036
Total realized and unrealized gains (losses) included in:					
Earnings (a)	(1,152)				(1,152)
Regulatory assets	(765)(b)				(765)
Regulatory liabilities	1,801(b)	229		412	2,442
Purchases	(3,307)	501		3,455	649
Sales	1,715	(16)	(305)	(80)	1,314
Settlements	300				300
Balance as of September 30, 2011	$ 10,407	$ 3,581	$	$ 6,836	$ 20,824

(a) Unrealized and realized gains and losses included in earnings are reported in revenues.

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

The following table provides reconciliations of assets and liabilities measured at fair value using significant level 3 inputs for the three and nine months ended September 30, 2010.

		Nuclear Decommissioning Trust			
	Energy Marketing Contracts, net	Domestic Equity	High-yield Bonds	Real Estate Securities	Net Balance
			(In Thousands)		
Balance as of June 30, 2010	$ 15,933	$ 2,547	$ 6,122	$ 2,772	$ 27,374
Total realized and unrealized gains (losses) included in:					
Earnings (a)	(11)				(11)
Regulatory assets	(644)(b)				(644)
Regulatory liabilities	2,191 (b)	(100)	(15)	90	2,166
Purchases, issuances and settlements	(2,944)		(5,802)		(8,746)
Transfers into level 2	(56)(c)				(56)
Balance as of September 30, 2010	$ 14,469	$ 2,447	$ 305	$ 2,862	$ 20,083
Balance as of December 31, 2009	$ 4,310	$ 2,262	$ 5,741	$ 3,635	$ 15,948
Total realized and unrealized gains (losses) included in:					
Earnings (a)	(1,840)				(1,840)
Regulatory assets	2,499 (b)				2,499
Regulatory liabilities	7,574 (b)	29	366	(773)	7,196
Purchases, issuances and settlements	1,926	156	(5,802)		(3,720)
Balance as of September 30, 2010	$ 14,469	$ 2,447	$ 305	$ 2,862	$ 20,083

(a) Unrealized and realized gains and losses included in earnings are reported in revenues.

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

(c) The fair value of transfers between levels is measured as of the beginning of the reporting period.

Portions of the gains and losses contributing to changes in net assets in the above tables are unrealized. The following tables summarize the unrealized gains and losses we recorded on our consolidated financial statements during the three and nine months ended September 30, 2011 and 2010, attributed to level 3 assets and liabilities.

		Three Months Ended September 30, 2011			
	Energy Marketing Contracts, net	Nuclear Decommissioning Trust Domestic Equity	 High-yield Bonds	 Real Estate Securities	Net Balance
			(In Thousands)		
Total unrealized gains (losses) included in:					
Earnings (a)	$ (264)	$	$	$	$ (264)
Regulatory assets	28(b)				28
Regulatory liabilities	590(b)	330		107	1,027
Total	$ 354	$ 330	$	$ 107	$ 791
		Nine Months Ended September 30, 2011			
Total unrealized gains (losses) included in:					
Earnings (a)	$ (570)	$	$	$	$ (570)
Regulatory assets	(233)(b)				(233)
Regulatory liabilities	1,101(b)	213		332	1,646
Total	$ 298	$ 213	$	$ 332	$ 843

(a) Unrealized gains and losses included in earnings are reported in revenues.
(b) Includes changes in the fair value of certain fuel supply and electricity contracts.

		Three Months Ended September 30, 2010			
	Energy Marketing Contracts, net	Nuclear Decommissioning Trust Domestic Equity	 High-yield Bonds	 Real Estate Securities	Net Balance
			(In Thousands)		
Total unrealized gains (losses) included in:					
Earnings (a)	$ (310)	$	$	$	$ (310)
Regulatory assets	(1,834)(b)				(1,834)
Regulatory liabilities	(461)(b)	(100)	(412)	90	(883)
Total	$ (2,605)	$ (100)	$ (412)	$ 90	$ (3,027)
		Nine Months Ended September 30, 2010			
Total unrealized gains (losses) included in:					
Earnings (a)	$ (490)	$	$	$	$ (490)
Regulatory assets	749(b)				749
Regulatory liabilities	4,765(b)	35	(31)	(773)	3,996
Total	$ 5,024	$ 35	$ (31)	$ (773)	$ 4,255

(a) Unrealized gains and losses included in earnings are reported in revenues.
(b) Includes changes in the fair value of certain fuel supply and electricity contracts.

Some of our investments in the NDT and all of our trading securities do not have readily determinable fair values and are either with investment companies or companies that follow accounting guidance consistent with investment companies. In certain situations these investments may have redemption restrictions. The following table provides additional information on these investments.

	As of September 30, 2011		As of December 31, 2010		As of September 30, 2011	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
		(In thousands)				
Nuclear Decommissioning Trust:						
Domestic equity	$ 3,581	$ 2,022	$ 2,867	$ 2,523	(a)	(a)
High-yield bonds			305		(b)	(b)
Real estate securities	6,836		3,049		(c)	(c)
Total Nuclear Decommissioning Trust	$ 10,417	$ 2,022	$ 6,221	$ 2,523		
Trading Securities:						
Domestic equity	$ 18,873	$	$ 21,207	$	Upon Notice	1 day
International equity	4,648		5,128		Upon Notice	1 day
Core bonds	13,743		13,077		Upon Notice	1 day
Total Trading Securities	37,264		39,412			
Total	$ 47,681	$ 2,022	$ 45,633	$ 2,523		

(a) This investment is in two long-term private equity funds that do not permit early withdrawal. Our investments in these funds cannot be distributed until the underlying investments have been liquidated which may take years from the date of initial liquidation. One fund has begun making distributions and we expect the other to begin in 2013.

(b) We completely settled this fund in the first quarter of 2011.

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

Derivative Instruments

Cash Flow Hedges

We have entered into treasury yield hedge transactions for a total notional amount of $125.0 million in an attempt to manage our interest rate risk associated with a future anticipated issuance of fixed rate debt, which is probable to occur within 18 months of the initial treasury yield hedge transaction date of July 21, 2010. Such transactions are designated and qualify as cash flow hedges and are measured at fair value by estimating the net present value of a series of payments using market-based models with observable inputs such as the spread between the 30-year U.S. Treasury bill yield and the contracted, fixed yield. As a result of regulatory accounting treatment, we report the effective portion of the gains or losses on these derivative instruments as a regulatory liability or regulatory asset and will amortize such amounts to interest expense over the life of the related debt. We record hedge ineffectiveness gains in other income and hedge ineffectiveness losses in other expense on our consolidated statements of income. As of September 30, 2011, we had recorded $31.3 million in other current liabilities on our consolidated balance sheet to reflect the fair value of the treasury yield hedge transactions and recorded this same amount in long-term regulatory assets to reflect the effective portion of the losses on these transactions. As of December 31, 2010, we had recorded $7.7 million in other assets to reflect the fair value of these transactions and recorded this same amount in long-term regulatory liabilities to reflect the effective portion of the gains on these transactions.

Commodity Contracts

We engage in both financial and physical trading with the goal of managing our commodity price risk, enhancing system reliability and increasing profits. We trade electricity and other energy-related products using a variety of financial instruments, which may include futures contracts, options, swaps and physical commodity contracts.

We classify these commodity derivative instruments as energy marketing contracts on our consolidated balance sheets. We report energy marketing contracts representing unrealized gain positions as assets; energy marketing contracts representing unrealized loss positions are reported as liabilities. With the exception of certain fuel supply and electricity contracts, which we record as regulatory assets or regulatory liabilities, we include the change in the fair value of energy marketing contracts in revenues on our consolidated statements of income.

The following table presents the fair value of commodity derivative instruments reflected on our consolidated balance sheets.

Commodity Derivatives Not Designated as Hedging Instruments as of September 30, 2011

Asset Derivatives		Liability Derivatives	
Balance Sheet Location	**Fair Value (In thousands)**	**Balance Sheet Location**	**Fair Value (In thousands)**
Current assets:		Current liabilities:	
Energy marketing contracts	$ 6,120	Energy marketing contracts	$ 3,031
Other assets:			
Energy marketing contracts	7,464		
Total	$ 13,584		

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

Asset Derivatives		Liability Derivatives	
Balance Sheet Location	**Fair Value (In thousands)**	**Balance Sheet Location**	**Fair Value (In thousands)**
Current assets:		Current liabilities:	
Energy marketing contracts	$ 13,005	Energy marketing contracts	$ 9,670
Other assets:		Long-term liabilities:	
Energy marketing contracts	9,472	Energy marketing contracts	10
Total	$ 22,477	Total	$ 9,680

The following table presents how changes in the fair value of commodity derivative instruments affected our consolidated financial statements for the three and nine months ended September 30, 2011 and 2010.

	Three Months Ended September 30, 2011		**Nine Months Ended September 30, 2011**	
Location	**Net Gain Recognized**	**Net Loss Recognized**	**Net Gain Recognized**	**Net Loss Recognized**
		(In thousands)		
Revenues decrease	$	$ (258)	$	$ (857)
Regulatory liabilities decrease		(8)		(1,215)
	Three Months Ended September 30, 2010		**Nine Months Ended September 30, 2010**	
Revenues increase (decrease)	$ 1,212	$	$	$ (597)
Regulatory assets decrease	(43)		(7,197)	
Regulatory liabilities (decrease) increase		(877)	4,051	

As of September 30, 2011, and December 31, 2010, we had under contract the following commodity derivatives.

		Net Quantity as of	
	Unit of Measure	September 30, 2011	December 31, 2010
Electricity	MWh	2,524,491	2,791,966
Natural Gas	MMBtu	92,000	1,150,000

Net open positions exist, or are established, due to the origination of new transactions and our assessment of, and response to, changing market conditions. To the extent we have net open positions, we are exposed to the risk that changing market prices could have a material adverse impact on our consolidated financial results.

Energy Marketing Activities

Within our energy trading portfolio, we may establish certain positions intended to economically hedge a portion of physical sale or purchase contracts and we may enter into certain positions attempting to take advantage of market trends and conditions. We use the term economic hedge to mean a strategy intended to manage risks of volatility in prices or rate movements on selected assets, liabilities or anticipated transactions by creating a relationship in which gains or losses on derivative instruments are expected to offset the losses or gains on the assets, liabilities or anticipated transactions exposed to such market risks.

Price Risk

We use various types of fuel, including coal, natural gas, uranium, diesel and oil, to operate our plants and also purchase power to meet customer demand. Our prices and consolidated financial results are exposed to market risks from commodity price changes for electricity and other energy-related products as well as interest rates. Volatility in these markets impacts our costs of purchased power, costs of fuel for our generating plants and our participation in energy markets. We strive to manage our customers and our exposure to these market risks through regulatory, operating and financing activities and, when we deem appropriate, we economically hedge a portion of these risks through the use of derivative financial instruments for non-trading purposes.

Interest Rate Risk

We have entered into fixed and variable rate debt obligations. We manage our interest rate risk related to these debt obligations by limiting our exposure to variable interest rate debt, diversifying maturity dates and entering into treasury yield hedge transactions. We may also use other financial derivative instruments such as interest rate swaps.

Credit Risk

In addition to commodity price risk, we are exposed to credit risks associated with the financial condition of counterparties, product location (basis) pricing differentials, physical liquidity constraints and other risks. Declines in the creditworthiness of our counterparties could have a material adverse impact on our overall exposure to credit risk. We maintain credit policies with regard to our counterparties intended to reduce our overall credit risk exposure to a level we deem acceptable and include the right to offset derivative assets and liabilities by counterparty.

We have derivative instruments with commodity exchanges and other counterparties that do not contain objective credit-risk-related contingent features. However, certain of our derivative instruments contain collateral provisions subject to credit agency ratings of our senior unsecured debt. If our senior unsecured debt ratings were to decrease or fall below investment grade, the counterparties to the derivative instruments, pursuant to the provisions, could require collateralization on derivative instruments. The aggregate fair value of all derivative instruments with objective credit-risk-related contingent features that were in a liability position as of September 30, 2011, and December 31, 2010, was $0.6 million and $1.6 million, respectively, for which we had posted no collateral as of September 30, 2011 and December 31, 2010. If all credit-risk-related contingent features underlying these agreements had been triggered as of September 30, 2011, and December 31, 2010, we would have been required to provide to our counterparties $0.5 million and $1.6 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

4. FINANCIAL INVESTMENTS

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

Trading Securities

We hold equity and debt investments in a trust used to fund retirement benefits that we classify as trading securities. We include unrealized gains or losses on these securities in investment earnings on our consolidated statements of income. During the three and nine months ended September 30, 2011, we recorded unrealized losses on these securities of $4.7 million and $2.6 million, respectively. We recorded unrealized gains on these securities of $3.2 million and $2.2 million, respectively, during the three and nine months ended September 30, 2010.

Available-for-Sale Securities

We hold investments in equity, debt and real estate securities in a trust for the purpose of funding the decommissioning of Wolf Creek. We have classified these investments as available-for-sale and have recorded all such investments at their fair market value as of September 30, 2011, and December 31, 2010. At September 30, 2011, investments in the NDT fund were allocated 40% to domestic equity, 18% to international equity, 19% to core bonds, 7% to high-yield bonds, 4% to emerging market bonds, 6% to combined debt/equity funds, 6% to real estate securities and less than 1% to cash and cash equivalents. The core bond fund has a requirement that at least 80% of funds are invested in investment grade U.S. corporate and government fixed income securities, including mortgage-backed securities. As of September 30, 2011, the fair value of available-for-sale debt securities in the core, high-yield and emerging market bond funds was $36.0 million. As of September 30, 2011, we had not invested in debt securities outside of investment funds.

Using the specific identification method to determine cost, we realized gains on our available-for-sale securities of $0.1 million and $1.3 million, respectively, during the three and nine months ended September 30, 2011. During the three and nine months ended September 30, 2010, we realized losses of $0.3 million and gains of $13.2 million, respectively, on these securities. We record net realized and unrealized gains and losses in regulatory liabilities on our consolidated balance sheets. This reporting is consistent with the method we use to account for the decommissioning costs we recover in our prices. Gains or losses on assets in the trust fund are recorded as increases or decreases to regulatory liabilities and could result in lower or higher funding requirements for decommissioning costs, which we believe would be reflected in the prices paid by our customers.

The following table presents the costs and fair values of investments in the NDT fund as of September 30, 2011, and December 31, 2010.

		Gross Unrealized		
Security Type	**Cost**	**Gain**	**Loss**	**Fair Value**
		(In Thousands)		
As of September 30, 2011:				
Domestic equity	$ 50,949	$ 103	$ (1,996)	$ 49,056
International equity	24,954		(3,112)	21,842
Core bonds	21,653	787		22,440
High-yield bonds	8,951		(374)	8,577
Emerging market bonds	4,929	46		4,975
Combination debt/equity fund	7,601		(324)	7,277
Real estate securities	9,662		(2,826)	6,836
Cash equivalents	47			47
Total	$ 128,746	$ 936	$ (8,632)	$ 121,050
As of December 31, 2010:				
Domestic equity	$ 58,592	$ 4,972	$ (111)	$ 63,453
International equity	17,249	1,717		18,966
Core bonds	32,054		(148)	31,906
High-yield bonds	9,086	486		9,572
Real estate securities	6,207		(3,158)	3,049
Cash equivalents	44			44
Total	$ 123,232	$ 7,175	$ (3,417)	$ 126,990

The following table presents the fair value and gross unrealized losses of the available-for-sale securities held in the NDT fund aggregated by investment category and the length of time that individual securities have been in a continuous unrealized loss position as of September 30, 2011, and December 31, 2010.

	Less than 12 Months		12 Months or Greater		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
			(In Thousands)			
As of September 30, 2011:						
Domestic equity	$ 45,475	$ (1,996)	$	$	$ 45,475	$ (1,996)
International equity	21,842	(3,112)			21,842	(3,112)
High-yield bonds	8,577	(374)			8,577	(374)
Combination debt/equity fund	7,277	(324)			7,277	(324)
Real estate securities			6,836	(2,826)	6,836	(2,826)
Total	$ 83,171	$ (5,806)	$ 6,836	$ (2,826)	$ 90,007	$ (8,632)
As of December 31, 2010:						
Domestic equity	$ 2,867	$ (111)	$	$	$ 2,867	$ (111)
Core bonds	31,906	(148)			31,906	(148)
Real estate securities			3,049	(3,158)	3,049	(3,158)
Total	$ 34,773	$ (259)	$ 3,049	$ (3,158)	$ 37,822	$ (3,417)

5. RATE MATTERS AND REGULATION

KCC Proceedings

On August 25, 2011, we filed an application with the Kansas Corporation Commission (KCC) proposing a $90.8 million increase in our annual retail prices. The primary drivers for the proposed increase were higher costs related to tree trimming, regulatory compliance, operating Wolf Creek and employee benefits. We expect the KCC to issue an order on our request in April 2012.

On February 23, 2011, Kansas City Power & Light Company (KCPL) filed an application requesting that the KCC predetermine the ratemaking principles for and determine the appropriateness of approximately $1.2 billion of environmental upgrades proposed for La Cygne Generating Station (La Cygne) to comply with environmental regulations. We have a 50% interest in La Cygne and intervened in the proceeding. On August 19, 2011, the KCC issued an order ruling that the decision to make the upgrades is prudent and the $1.2 billion project cost estimate is reasonable. The KCC denied our request to collect our approximately $600.0 million share of the costs of the environmental upgrades through our environmental cost recovery rider (ECRR). However, we requested in the application to increase retail prices noted above that we be allowed to file an abbreviated rate case within 12 months of the KCC s order in that proceeding to begin collecting costs associated with our investment.

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

On April 11, 2011, the KCC issued an order allowing us to adjust our prices, subject to final KCC review, to include updated transmission costs as reflected in our transmission formula rate discussed below. The new prices were effective April 14, 2011, and are expected to increase our annual retail revenues by approximately $17.4 million. The timing of the KCC s final order on our request is uncertain.

FERC Proceedings

Our transmission formula rate that includes projected 2011 transmission capital expenditures and operating costs became effective January 1, 2011, and is expected to increase our annual transmission revenues by approximately $15.9 million. This updated rate provided the basis for our request with the KCC to adjust our retail prices to include updated transmission costs as noted above.

6. SHORT-TERM DEBT

On September 29, 2011, Westar Energy refinanced its existing $730.0 million revolving credit facility with a new facility in the same amount. The commitments under the new facility terminate on September 29, 2016. As long as there is no default under the facility, Westar Energy may extend the facility up to an additional two years and may increase the aggregate amount of borrowings under the facility to $1.0 billion, both subject to lender participation. As of September 30, 2011, $391.9 million had been borrowed and an additional $12.8 million of letters of credit had been issued under this revolving credit facility. As of December 31, 2010, $226.7 million had been borrowed and an additional $21.5 million of letters of credit had been issued under Westar Energy s previous $730.0 million revolving credit facility.

On February 18, 2011, Westar Energy entered into a revolving credit facility with a syndicate of banks for $270.0 million. The commitments under this facility terminate on February 18, 2015. As long as there is no default under the facility, Westar Energy may extend the facility up to an additional two years and may increase the aggregate amount of borrowings under the facility to $400.0 million, both subject to lender participation. As of September 30, 2011, Westar Energy had neither borrowed monies nor issued letters of credit under this revolving credit facility.

7. TAXES

We recorded income tax expense of $61.7 million with an effective income tax rate of 31% for the three months ended September 30, 2011, and income tax expense of $51.8 million with an effective income tax rate of 31% for the same period of 2010; and income tax expense of $94.8 million with an effective income tax rate of 31% for the nine months ended September 30, 2011, and income tax expense of $86.8 million with an effective income tax rate of 30% for the same period of 2010.

In 2010, we established a valuation allowance of $51.9 million against the unused state investment tax credits of $116.2 million. We reversed this valuation allowance during the second quarter of 2011 due to a state law change which extended the state investment tax credit carryforward period from 10 to 16 years.

At September 30, 2011, and December 31, 2010, our liability for unrecognized income tax benefits was $4.3 million and $1.9 million, respectively. The net increase in the liability for unrecognized income tax benefits was largely attributable to tax positions taken with respect to the capitalization of plant related expenditures. We do not expect any significant changes in this liability in the next 12 months.

As of September 30, 2011, and December 31, 2010, we had $0.4 million accrued for interest on our liability for unrecognized income tax benefits. We accrued no penalties at either September 30, 2011, or December 31, 2010.

As of September 30, 2011, and December 31, 2010, we had recorded $3.6 million for probable assessments of taxes other than income taxes.

8. COMMITMENTS AND CONTINGENCIES

Federal Clean Air Act

We must comply with the Federal Clean Air Act, state laws and implementing regulations that impose, among other things, limitations on emissions generated during our operations, including sulfur dioxide (SO_2), particulate matter, nitrogen oxides (NOx) and mercury. In addition, we must comply with the provisions of the Federal Clean Air Act Amendments of 1990 that require reductions in SO_2 and NOx.

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

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

In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. We are currently evaluating what impact this could have on our operations. If we are required to install additional equipment to control emissions at our facilities, the revised NAAQS could have a material impact on our operations and consolidated financial results.

Environmental Projects

We will continue to make significant capital expenditures at our power plants to reduce regulated emissions. The amount of these expenditures could change materially depending on the timing and nature of required investments, the specific outcomes resulting from interpretation of existing regulations, new regulations, legislation and the manner in which we operate the plants. In addition to the capital investment, in the event we install new equipment, such equipment may cause us to incur significant increases in annual operating and maintenance expense and may reduce the net production, reliability and availability of the plants. The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. Additionally, our ability to access capital markets and the availability of materials, equipment and contractors may affect the timing and ultimate amount of such capital investments.

In comparison to a general rate case, the ECRR reduces the amount of time it takes to begin collecting in retail prices the costs of capital expenditures associated with environmental improvements, including those required by the Federal Clean Air Act. As previously discussed, we are not allowed to use the ECRR to collect our approximately $600.0 million share of the costs associated with the $1.2 billion of environmental upgrades at La Cygne. We must file an abbreviated rate case or general rate case with the KCC in order to collect these costs. In order to change our prices to collect increased operating and maintenance costs, we must file a general rate case with the KCC.

Air Emissions

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) which requires 27 states, including Kansas, to further reduce power plant emissions of SO_2 and NOx. Under CSAPR, reductions in annual SO_2 and NOx emissions are required to begin January 1, 2012, with further reductions required beginning January 1, 2014. The EPA is issuing federal implementation plans for each state covered by CSAPR, but is allowing states to submit their own implementation plans starting as early as 2013.

There are a number of uncertainties relating to CSAPR, including how Kansas will implement the requirements. In addition, the implementation timeline for the finalized portion of CSAPR is abbreviated in comparison to EPA precedent for regulations of similar magnitude. To comply with the rule on January 1, 2012, we expect that we must modify the way in which we use our power plants, purchase power or purchase emission allowances, as there is insufficient time to install equipment needed to reduce emissions to the levels required by the rule. We believe compliance with the rule may impact the reliability of our electrical service. We could incur substantial fines and penalties for noncompliance. We cannot yet determine the impact this new rule will have on our operations or consolidated financial results, but it could be material.

Greenhouse Gases

Under EPA regulations finalized in May 2010, known as the tailoring rule, the EPA began regulating greenhouse gas (GHG) emissions from certain stationary sources in January 2011. The regulations are being implemented pursuant to two Federal Clean Air Act programs: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications, which is referred to as the Prevention of Significant Deterioration program (PSD). Obligations relating to Title V permits will include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors), will be required to implement best available control technology (BACT). The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. We cannot at this time determine the impact of these new regulations on our operations and consolidated financial results, but we believe the cost of compliance with new regulations could be material.

Renewable Energy Standard

In May 2009, Kansas enacted legislation that mandates, among other requirements, that more energy be derived from renewable sources. In years 2011 through 2015 net renewable generation capacity must be 10% of the average peak demand for the three prior years, subject to limited exceptions. This requirement increases to 15% for years 2016 through 2019 and 20% for 2020 and thereafter. We have worked with third parties to develop approximately 300 megawatts (MW) of qualifying renewable generation facilities which, together with the use of renewable energy credits, we expect will allow us to meet the 2011 requirement. In an order dated May 9, 2011, the KCC approved two separate agreements we entered into with third parties to purchase under 20-year supply contracts the renewable energy produced from approximately 370 MW of renewable generation beginning in late 2012 and the associated cost recovery. We expect these agreements, along with our prior development of renewable generation facilities, to satisfy our net renewable generation requirement through 2015 and contribute toward meeting the increased requirement beginning in 2016. If we are unable to meet future requirements, our operations and consolidated financial results could be adversely impacted.

Manufactured Gas Sites

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

EPA Lawsuit

In March 2010, the U.S. District Court in the District of Kansas approved a settlement agreement that we entered into with the parties of a lawsuit filed by the Department of Justice on behalf of the EPA. The lawsuit asserted that certain projects completed at JEC violated certain requirements of the EPA s New Source Review program, which requires companies to obtain permits and, if necessary, install control equipment to address emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in emissions. As part of the settlement agreement, in 2009 we recorded $1.0 million for environmental mitigation projects that will be owned by a qualifying third party and a $3.0 million civil penalty. We will also invest $5.0 million over six years in environmental mitigation projects that we will own. In addition, we will install a selective catalytic reduction (SCR) on one of the three JEC coal units by the end of 2014. We estimate the cost of this to be approximately $240.0 million. Depending on the NOx emission reductions attained by the single SCR and attainable through the installation of other controls on the other two JEC coal units, we may have to install an SCR on another JEC unit by the end of 2016, if needed to meet plant-wide NOx reduction targets. We believe recovery of the costs to install these systems is recoverable through our ECRR, but remains subject to the approval of our regulators. We believe these costs are appropriate for inclusion in the prices we are allowed to charge customers.

FERC Investigation

A non-public investigation by the Federal Energy Regulatory Commission (FERC) of our use of transmission service between July 2006 and February 2008 remains pending. In May 2009, FERC staff alleged that we improperly used secondary network transmission service to facilitate off-system wholesale power sales in violation of applicable FERC orders and Southwest Power Pool (SPP) tariffs. FERC staff first alleged we received $14.3 million of unjust profits through such activities. We sent a response to FERC staff disputing both the legal basis for its allegations and their factual underpinnings. Based on our response, FERC staff substantially revised downward its preliminary conclusions to allege that we received $3.0 million of unjust profits and failed to pay $3.2 million to the SPP for transmission service. In March 2010, we sent a response to FERC staff disputing its revised conclusions. From time to time we respond to questions from FERC staff. We continue to believe that our use of transmission service was in compliance with FERC orders and SPP tariffs. We are unable to predict the outcome of this investigation or its impact on our consolidated financial results, but an adverse outcome could result in refunds and fines, the amounts of which could be material, and could potentially alter the manner in which we are permitted to buy and sell energy and use transmission service.

9. LEGAL PROCEEDINGS

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

We and our subsidiaries are involved in various other legal, environmental and regulatory proceedings. We believe that adequate provisions have been made and accordingly believe that the ultimate disposition of such matters will not have a material adverse affect on our consolidated financial results. See Note 5, Rate Matters and Regulation, and Note 8, Commitments and Contingencies, for additional information.

10. INTERIM PENSION AND POST-RETIREMENT BENEFIT DISCLOSURE

The following table summarizes the net periodic costs for our pension and post-retirement benefit plans prior to the effects of capitalization.

	Pension Benefits		**Post-retirement Benefits**	
Three Months Ended September 30,	**2011**	**2010**	**2011**	**2010**
		(In Thousands)		
Components of Net Periodic Cost:				
Service cost	$ 4,019	$ 3,481	$ 451	$ 381
Interest cost	9,958	9,848	1,698	1,771
Expected return on plan assets	(7,772)	(9,596)	(1,250)	(1,299)
Amortization of unrecognized:				
Transition obligation, net			978	978
Prior service costs	303	682	631	539
Actuarial loss, net	5,915	4,296	175	80
Net periodic cost before regulatory adjustment	12,423	8,711	2,683	2,450
Regulatory adjustment	(5,640)	(3,119)	308	444
Net periodic cost	$ 6,783	$ 5,592	$ 2,991	$ 2,894

	Pension Benefits		**Post-retirement Benefits**	
Nine Months Ended September 30,	**2011**	**2010**	**2011**	**2010**
		(In Thousands)		
Components of Net Periodic Cost:				
Service cost	$ 12,057	$ 10,444	$ 1,352	$ 1,144
Interest cost	29,873	29,544	5,095	5,312
Expected return on plan assets	(23,316)	(28,788)	(3,751)	(3,898)
Amortization of unrecognized:				
Transition obligation, net			2,934	2,934
Prior service costs	910	2,047	1,893	1,616
Actuarial loss, net	17,744	12,887	527	241
Net periodic cost before regulatory adjustment	37,268	26,134	8,050	7,349
Regulatory adjustment	(16,907)	(9,357)	934	1,331
Net periodic cost	$ 20,361	$ 16,777	$ 8,984	$ 8,680

During the nine months ended September 30, 2011 and 2010, we contributed $50.0 million and $22.4 million, respectively, to the Westar Energy pension trust.

11. WOLF CREEK INTERIM PENSION AND POST-RETIREMENT BENEFIT DISCLOSURE

As a co-owner of Wolf Creek, KGE is indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement benefit plans. The following table summarizes the net periodic costs for KGE s 47% share of the Wolf Creek pension and post-retirement benefit plans prior to the effects of capitalization.

Three Months Ended September 30,	Pension Benefits 2011	Pension Benefits 2010	Post-retirement Benefits 2011	Post-retirement Benefits 2010
		(In Thousands)		
Components of Net Periodic Cost:				
Service cost	$ 1,239	$ 1,036	$ 41	$ 45
Interest cost	1,843	1,735	115	130
Expected return on plan assets	(1,476)	(1,363)		
Amortization of unrecognized:				
Transition obligation, net	13	14	14	14
Prior service costs	4	7		
Actuarial loss, net	896	659	57	69
Net periodic cost before regulatory adjustment	2,519	2,088	227	258
Regulatory adjustment	(660)	(394)		
Net periodic cost	$ 1,859	$ 1,694	$ 227	$ 258

Nine Months Ended September 30,	Pension Benefits 2011	Pension Benefits 2010	Post-retirement Benefits 2011	Post-retirement Benefits 2010
		(In Thousands)		
Components of Net Periodic Cost:				
Service cost	$ 3,718	$ 3,108	$ 124	$ 134
Interest cost	5,527	5,206	344	390
Expected return on plan assets	(4,429)	(4,090)		
Amortization of unrecognized:				
Transition obligation, net	39	42	43	43
Prior service costs	12	22		
Actuarial loss, net	2,689	1,976	171	207
Net periodic cost before regulatory adjustment	7,556	6,264	682	774
Regulatory adjustment	(1,980)	(1,182)		
Net periodic cost	$ 5,576	$ 5,082	$ 682	$ 774

During the nine months ended September 30, 2011 and 2010, we funded $8.6 million and $5.1 million, respectively, of Wolf Creek s pension plan contribution.

12. COMMON STOCK

During the nine months ended September 30, 2011, Westar Energy delivered approximately 4.2 million shares of common stock as settlement of the forward sale agreement entered into in April 2010. In connection with these settlement transactions, Westar Energy received proceeds of approximately $91.9 million. Westar Energy used the proceeds from the issuance of common stock to repay borrowings under its revolving credit facility, with such borrowed amounts principally related to investments in capital equipment, as well as for working capital and general corporate purposes.

During the nine months ended September 30, 2011, Westar Energy did not deliver any shares of common stock under the forward sale agreement entered into in November 2010. Assuming physical share settlement of the approximately 8.5 million shares of common stock under this agreement at September 30, 2011, Westar Energy would have received aggregate proceeds of approximately $197.4 million based on a forward price of $23.28 per share.

On May 19, 2011, Westar Energy shareholders approved an amendment to its Restated Articles of Incorporation to increase the number of shares of common stock authorized to be issued from 150.0 million to 275.0 million.

13. VARIABLE INTEREST ENTITIES

In determining the primary beneficiary of a VIE, we assess the entity s purpose and design, including the nature of the entity s activities and the risks that the entity was designed to create and pass through to its variable interest holders. A reporting enterprise is deemed to be the primary beneficiary of a VIE if it has (a) the power to direct the activities of the VIE that most significantly impact the VIE s economic performance and (b) the obligation to absorb losses or right to receive benefits from the VIE that could potentially be significant to the VIE. The primary beneficiary of a VIE is required to consolidate the VIE. The trusts holding our 8% interest in JEC, our 50% interest in La Cygne unit 2 and railcars we use to transport coal to some of our plants are VIEs of which we are the primary beneficiary.

We assess all entities with which we become involved to determine whether such entities are VIEs and, if so, whether or not we are the primary beneficiary of the entities. We also continuously assess whether we are the primary beneficiary of the VIEs with which we are involved. Prospective changes in facts and circumstances may cause us to reconsider our determination as it relates to the identification of the primary beneficiary.

8% Interest in Jeffrey Energy Center

Under an agreement that expires in January 2019, we lease an 8% interest in JEC from a trust. The trust was financed with an equity contribution from an owner participant and debt issued by the trust. The trust was created specifically to purchase the 8% interest in JEC and lease it to a third party, and does not hold any other assets. We meet the requirements to be considered the primary beneficiary of the trust. In determining the primary beneficiary of the trust, we concluded that the activities of the trust that most significantly impact its economic performance and that we have the power to direct include (1) the operation and maintenance of the 8% interest in JEC, (2) our ability to exercise a purchase option at the end of the agreement at the lesser of fair value or a fixed amount and (3) our option to require refinancing of the trust s debt. We have the potential to receive benefits from the trust that could potentially be significant if the fair value of the 8% interest in JEC at the end of the agreement is greater than the fixed amount. The possibility of lower interest rates upon refinancing the debt also creates the potential for us to receive significant benefits.

50% Interest in La Cygne Unit 2

Under an agreement that expires in September 2029, KGE entered into a sale-leaseback transaction with a trust under which the trust purchased KGE s 50% interest in La Cygne unit 2 and subsequently leased it back to KGE. The trust was financed with an equity contribution from an owner participant and debt issued by the trust. The trust was created specifically to purchase the 50% interest in La Cygne unit 2 and lease it back to KGE, and does not hold any other assets. We meet the requirements to be considered the primary beneficiary of the trust. In determining the primary beneficiary of the trust, we concluded that the activities of the trust that most significantly impact its economic performance and that we have the power to direct include (1) the operation and maintenance of the 50% interest in La Cygne unit 2, (2) our ability to exercise a purchase option at the end of the agreement at the lesser of fair value or a fixed amount and (3) our option to require refinancing of the trust s debt. We have the potential to receive benefits from the trust that could potentially be significant if the fair value of the 50% interest in La Cygne unit 2 at the end of the agreement is greater than the fixed amount. The possibility of lower interest rates upon refinancing the debt also creates the potential for us to receive significant benefits.

Railcars

Under two separate agreements that expire in May 2013 and November 2014, we lease railcars from trusts to transport coal to some of our power plants. The trusts were financed with equity contributions from owner participants and debt issued by the trusts. The trusts were created specifically to purchase the railcars and lease them to us, and do not hold any other assets. We meet the requirements to be considered the primary beneficiary of the trusts. In determining the primary beneficiary of the trusts, we concluded that the activities of the trusts that most significantly impact their economic performance and that we have the power to direct include the operation, maintenance and repair of the railcars and our ability to exercise a purchase option at the end of the agreements at the lesser of fair value or a fixed amount. We have the potential to receive benefits from the trusts that could potentially be significant if the fair value of the railcars at the end of the agreements is greater than the fixed amounts. Our agreements with these trusts also include renewal options during which time we would pay a fixed amount of rent. We have the potential to receive benefits from the trusts during the renewal periods if the fixed amount of rent is less than the amount we would be required to pay under a new agreement.

Financial Statement Impact

We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIEs described above.

	As of September 30, 2011	As of December 31, 2010
	(In Thousands)	
Assets:		
Property, plant and equipment of variable interest entities, net	$ 336,373	$ 345,037
Regulatory asset (a)	4,690	3,963
Liabilities:		
Current maturities of long-term debt of variable interest entities	$ 28,091	$ 30,155
Accrued interest (b)	508	5,064
Long-term debt of variable interest entities, net	250,632	278,162

(a) Included in long-term regulatory assets on our consolidated balance sheets.

(b) Included in accrued interest on our consolidated balance sheets.

All of the liabilities noted in the table above relate to the VIEs ownership of the reported property, plant and equipment. The assets of the VIEs can be used only to settle obligations of the VIEs and the VIEs debt holders have no recourse to our general credit. We have not provided financial or other support to the VIEs and are not required to provide such support. We did not record any gain or loss upon initial consolidation of the VIEs.

14. LEASES

Capital Leases

We identify capital leases based on defined criteria. For both vehicles and computer equipment, new leases are signed each month based on the terms of master lease agreements. The lease term for vehicles is from two to seven years depending on the type of vehicle. Computer equipment has a lease term of four to five years.

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

Assets recorded under capital leases are listed below.

	September 30, 2011	December 31, 2010
	(In Thousands)	
Vehicles	$ 14,879	$ 12,504
Computer equipment and software	1,750	5,551
Power supply agreement	40,048	
Accumulated amortization	(6,198)	(8,744)
Total capital leases	$ 50,479	$ 9,311

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

Total Capital Leases	September 30, 2011	December 31, 2010
	(In Thousands)	
2011	$ 1,479	$ 2,110
2012	5,437	2,213
2013	5,620	1,908
2014	5,209	1,792
2015	4,808	1,391
Thereafter	72,212	1,157
	94,765	10,571
Amounts representing imputed interest	(44,286)	(1,260)
Present value of net minimum lease payments under capital leases	50,479	9,311
Less: current portion	2,607	1,797
Total long-term obligation under capital leases	$ 47,872	$ 7,514

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

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 operating results for the three and nine months ended September 30, 2011 and 2010, our general financial condition and significant changes that occurred during 2011. As you read Management s Discussion and Analysis, please refer to our condensed consolidated financial statements and the accompanying notes, which contain our operating results.

SUMMARY OF SIGNIFICANT ITEMS

Earnings Per Share

Following is a summary of our net income and basic EPS.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change	2011	2010	Change
	(Thousands of Dollars, Except per Share Amounts)			(Thousands of Dollars, Except per Share Amounts)		
Net income attributable to common stock	$ 134,708	$ 114,502	$ 20,206	$ 209,935	$ 198,009	$ 11,926
Earnings per common share, basic	1.15	1.02	0.13	1.82	1.77	0.05

During the third quarter of 2011, we reversed $22.0 million of previously accrued liabilities as a result of the legal settlements discussed in Note 9 of the Notes to Condensed Consolidated Financial Statements, Legal Proceedings, and recorded a $7.2 million gain on the sale of a fully impaired non-utility investment. These two factors were the primary drivers for the increase in net income attributable to common stock for both the three and nine months ended September 30, 2011, compared to the same periods last year. See the discussion under Operating Results below for additional factors that affected our net income attributable to common stock for the three and nine months ended September 30, 2011.

Current Trends

From time to time we update current trends discussed in our 2010 Form 10-K. The following is to be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations in our 2010 Form 10-K.

Environmental Regulation

Environmental laws and regulations affecting power plants, which relate primarily to discharges into the air, air quality, discharges of effluents into water, the use of water, and the handling, disposal and clean-up of hazardous and non-hazardous substances and wastes, continue to evolve and have become more stringent and costly over time. We have incurred and will continue to incur significant capital and other expenditures, and could potentially have to limit the use of some of our power plants, to comply with existing and new environmental laws and regulations. While certain of these costs are recoverable through the ECRR, and ultimately we expect that all such costs will be reflected in the prices we are allowed to charge customers, we cannot assure that all such costs will be recovered in a timely manner.

Air Emissions

In July 2011, the EPA finalized CSAPR which requires 27 states, including Kansas, to further reduce power plant emissions of SO_2 and NOx. Under CSAPR, reductions in annual SO_2 and NOx emissions are required to begin January 1, 2012, with further reductions required beginning January 1, 2014. The EPA is issuing federal implementation plans for each state covered by CSAPR, but is allowing states to submit their own implementation plans starting as early as 2013.

Additionally, also in July 2011, the EPA proposed to require six states, including Kansas, to make summertime reductions in NOx emissions under an ozone-season control program implemented under CSAPR. Reductions in ozone-season NOx under this proposal would begin May 1, 2012. The EPA expects to finalize this proposal by October 31, 2011.

In October 2011, we filed legal challenges to CSAPR in the District of Columbia Circuit Court of Appeals. On October 6, 2011, the EPA issued a proposed rule that, according to the EPA, would slightly ease the new emission standards and defer the effective date of certain penalty provisions from January 1, 2012, to January 1, 2014. We continue to review and analyze this proposed rule, but do not believe that it will substantially change the impacts of CSAPR.

There are a number of uncertainties relating to CSAPR, including how Kansas will implement the requirements, and whether the proposed rule relating to ozone-season NOx reductions will be finalized. In addition, the implementation timeline for the finalized portion of CSAPR is abbreviated in comparison to EPA precedent for regulations of similar magnitude. To comply with the rule on January 1, 2012, we expect that we must modify the way in which we use our power plants, purchase power or purchase emission allowances, as there is insufficient time to install equipment needed to reduce emissions to the levels required by the rule. We believe compliance with the rule may impact the reliability of our electrical service. We could incur substantial fines and penalties for noncompliance. We cannot yet determine the impact this new rule will have on our operations or consolidated financial results, but it could be material.

In March 2011, the EPA proposed Mercury and Air Toxic Standards for power plants, which would replace the prior federal Clean Air Mercury Rule and would require significant reductions of mercury emissions as well as other air toxics from coal-fired power plants. A final rule is expected in November 2011. Without knowing what the rule will require, we cannot estimate the impact on us. However, our costs to comply with future mercury and air toxics emission requirements could have a material impact on our operations and consolidated financial results.

Greenhouse Gases

In December 2010, the EPA announced that it would be proposing GHG New Source Performance Standard rules for power plants and refineries. The rules will apply to new and existing facilities. The EPA had announced that it would propose the new rules by September 30, 2011, but has postponed the proposed rules until October 2011. The EPA expects to finalize the rules in May 2012. Because these regulations have yet to be proposed, we cannot predict the impact they may have on our operations or consolidated financial results, but it could be material.

National Ambient Air Quality Standards

The EPA had been in the process of revising the NAAQS for ozone. However, on September 2, 2011, President Obama ordered the EPA to withdraw its proposal. The EPA plans to revisit the standards in 2013.

Regulation of Nuclear Generating Station

Additional regulation of Wolf Creek resulting from NRC oversight of the plant s performance or from changing regulations generally, including those that could potentially result from natural disasters or any event that might occur at any nuclear power plant anywhere in the world, may result in increased operating and capital expenditures. We cannot estimate the cost associated with such increases, but they could be material to our operations and consolidated financial results.

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

Coal Inventory and Delivery

Starting in late June and continuing through October, coal deliveries from the Powder River Basin region of Wyoming have been slower than normal due primarily to flooding that occurred in the Midwest, which shut down portions of the rail lines throughout the region. While October experienced improved delivery times, we are still experiencing some rerouting of the trains that deliver coal to our power plants and are encountering some residual congestion on the rail lines. We expect delivery times to return to normal levels during the fourth quarter of 2011.

In response to the above issues, we implemented compensating measures based on delivery times, our assumptions about future delivery times, fuel usage and planned inventory levels. These measures included, but were not limited to, reducing coal consumption during lower priced periods, purchasing power and decreasing wholesale sales.

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 the instructions to Form 10-Q and Article 10 of Regulation S-X. Note 2 of the Notes to Condensed Consolidated Financial Statements, Summary of Significant Accounting Policies, contains a summary of our significant accounting policies, many of which require estimates and assumptions by management. The policies highlighted in our 2010 Form 10-K 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.

From December 31, 2010, through September 30, 2011, we have not experienced any significant changes in our critical accounting estimates. For additional information, see our 2010 Form 10-K.

OPERATING RESULTS

We evaluate operating results based on EPS. We have various classifications of revenues, defined as follows:

Retail: Sales of electricity to residential, commercial and industrial customers. Classification of customers as residential, commercial or industrial requires judgment and our classifications may be different from other companies. Assignment of tariffs is not dependent on classification.

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

Wholesale: Sales of electricity to electric cooperatives, municipalities and other electric utilities, the prices for which are either based on cost or prevailing market prices as prescribed by FERC authority. This category also includes changes in valuations of contracts for the sale of such electricity that have yet to settle. Margins realized from sales based on prevailing market prices generally serve to offset our retail prices and the cost-based prices charged to certain wholesale customers.

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

Other: Miscellaneous electric revenues including ancillary service revenues and rent from electric property leased to others. This category also includes energy marketing transactions unrelated to the production of our generating assets, changes in valuations of related contracts and fees we earn for marketing services that we provide for third parties.

Electric utility revenues are impacted by things such as rate regulation, fuel costs, customer conservation efforts, the economy and competitive forces. Changing weather also affects the amount of electricity our customers use as electricity sales are seasonal. As a summer peaking utility, the third quarter typically accounts for our greatest electricity sales. Hot summer temperatures and cold winter temperatures prompt more demand, especially among residential customers. Mild weather reduces customer demand. Our wholesale revenues are impacted by, among other factors, demand, cost and availability of fuel and purchased power, price volatility, available generation capacity, transmission availability and weather.

Three and Nine Months Ended September 30, 2011, Compared to Three and Nine Months Ended September 30, 2010

Below we discuss our operating results for the three and nine months ended September 30, 2011, compared to the results for the three and nine months ended September 30, 2010. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	% Change	2011	2010	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)				(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:								
Residential	$ 246,756	$ 235,383	$ 11,373	4.8	$ 556,784	$ 530,220	$ 26,564	5.0
Commercial	188,070	179,884	8,186	4.6	470,452	443,892	26,560	6.0
Industrial	98,060	90,462	7,598	8.4	268,501	242,612	25,889	10.7
Other retail	(3,304)	(3,404)	100	2.9	(8,759)	(10,463)	1,704	16.3
Total Retail Revenues	529,582	502,325	27,257	5.4	1,286,978	1,206,261	80,717	6.7
Wholesale	101,086	94,117	6,969	7.4	257,195	255,865	1,330	0.5
Transmission (a)	39,075	35,554	3,521	9.9	115,411	108,497	6,914	6.4
Other	8,409	12,441	(4,032)	(32.4)	25,179	28,825	(3,646)	(12.6)
Total Revenues	678,152	644,437	33,715	5.2	1,684,763	1,599,448	85,315	5.3
OPERATING EXPENSES:								
Fuel and purchased power	199,540	187,877	11,663	6.2	486,697	458,793	27,904	6.1
Operating and maintenance	137,823	126,602	11,221	8.9	412,429	369,584	42,845	11.6
Depreciation and amortization	72,202	67,918	4,284	6.3	213,551	201,955	11,596	5.7
Selling, general and administrative	27,499	50,418	(22,919)	(45.5)	132,233	144,499	(12,266)	(8.5)
Total Operating Expenses	437,064	432,815	4,249	1.0	1,244,910	1,174,831	70,079	6.0
INCOME FROM OPERATIONS	241,088	211,622	29,466	13.9	439,853	424,617	15,236	3.6
OTHER INCOME (EXPENSE):								
Investment earnings	2,914	3,248	(334)	(10.3)	6,255	4,350	1,905	43.8
Other income	3,404	1,897	1,507	79.4	8,210	3,792	4,418	116.5
Other expense	(5,470)	(5,146)	(324)	(6.3)	(13,951)	(12,043)	(1,908)	(15.8)
Total Other Income (Expense)	848	(1)	849	(b)	514	(3,901)	4,415	113.2
Interest expense	43,844	43,956	(112)	(0.3)	130,681	131,862	(1,181)	(0.9)
INCOME BEFORE INCOME TAXES	198,092	167,665	30,427	18.1	309,686	288,854	20,832	7.2
Income tax expense	61,700	51,802	9,898	19.1	94,812	86,780	8,032	9.3
NET INCOME	136,392	115,863	20,529	17.7	214,874	202,074	12,800	6.3
Less: Net income attributable to noncontrolling interests	1,442	1,119	323	28.9	4,212	3,338	874	26.2
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY	134,950	114,744	20,206	17.6	210,662	198,736	11,926	6.0
Preferred dividends	242	242			727	727		

NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 134,708	$ 114,502	$ 20,206	17.6	$ 209,935	$ 198,009	$ 11,926	6.0
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY	$ 1.15	$ 1.02	$ 0.13	12.7	$ 1.82	$ 1.77	$ 0.05	2.8

(a) **Transmission:** Reflects revenue from an SPP network transmission tariff. For the three and nine months ended September 30, 2011, our SPP network transmission costs were $33.9 million and $98.6 million, respectively. These amounts, less administration costs of $5.3 million and $13.6 million, respectively, were returned to us as revenue. For the three and nine months ended September 30, 2010, our SPP network transmission costs were $30.7 million and $86.7 million, respectively. These amounts, plus $0.3 million and less administration costs of $7.4 million, respectively, were returned to us as revenue.

(b) Change greater than 1000%.

Gross Margin

Fuel and purchased power costs fluctuate with electricity sales and unit costs. As permitted by regulators, we adjust our retail prices to reflect changes in the costs of fuel and purchased power. Fuel and purchased power costs for wholesale customers are recovered at prevailing market prices or based on a predetermined formula with a price adjustment approved by FERC. As a result, changes in fuel and purchased power costs are offset in revenues with minimal impact on net income. For this reason, we believe gross margin is useful for understanding and analyzing changes in our operating performance from one period to the next. We calculate gross margin as total revenues less the sum of fuel and purchased power costs and SPP network transmission costs. Transmission costs reflect the costs of providing network transmission service. Accordingly, in calculating gross margin, we recognize the net value of this transmission activity as shown in the table immediately following. However, we record transmission costs as operating and maintenance expense on our consolidated statements of income. The following table summarizes our gross margin for the three and nine months ended September 30, 2011 and 2010.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	% Change	2011	2010	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)				(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:								
Residential	$ 246,756	$ 235,383	$ 11,373	4.8	$ 556,784	$ 530,220	$ 26,564	5.0
Commercial	188,070	179,884	8,186	4.6	470,452	443,892	26,560	6.0
Industrial	98,060	90,462	7,598	8.4	268,501	242,612	25,889	10.7
Other retail	(3,304)	(3,404)	100	2.9	(8,759)	(10,463)	1,704	16.3
Total Retail Revenues	529,582	502,325	27,257	5.4	1,286,978	1,206,261	80,717	6.7
Wholesale	101,086	94,117	6,969	7.4	257,195	255,865	1,330	0.5
Transmission	39,075	35,554	3,521	9.9	115,411	108,497	6,914	6.4
Other	8,409	12,441	(4,032)	(32.4)	25,179	28,825	(3,646)	(12.6)
Total Revenues	678,152	644,437	33,715	5.2	1,684,763	1,599,448	85,315	5.3
Less: Fuel and purchased power expense	199,540	187,877	11,663	6.2	486,697	458,793	27,904	6.1
SPP network transmission costs	33,887	30,682	3,205	10.4	98,623	86,746	11,877	13.7
Gross Margin	$ 444,725	$ 425,878	$ 18,847	4.4	$ 1,099,443	$ 1,053,909	$ 45,534	4.3

The following table reflects changes in electricity sales for the three and nine months ended September 30, 2011 and 2010. No electricity sales are shown for transmission or other as they are not directly related to the amount of electricity we sell.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	% Change	2011	2010	Change	% Change
	(Thousands of MWh)				(Thousands of MWh)			
ELECTRICITY SALES:								
Residential	2,372	2,351	21	0.9	5,579	5,563	16	0.3
Commercial	2,232	2,218	14	0.6	5,825	5,793	32	0.6
Industrial	1,528	1,483	45	3.0	4,304	4,166	138	3.3
Other retail	21	23	(2)	(8.7)	66	65	1	1.5
Total retail	6,153	6,075	78	1.3	15,774	15,587	187	1.2
Wholesale	2,122	2,304	(182)	(7.9)	5,808	6,804	(996)	(14.6)
Total	8,275	8,379	(104)	(1.2)	21,582	22,391	(809)	(3.6)

Gross margin increased for the three and nine months ended September 30, 2011, compared to the same periods last year due primarily to higher total retail revenues, which were the result of higher prices and increased electricity sales as presented in the following table.

	Three Months Ended September 30, 2011	**Nine Months Ended September 30, 2011**
Increase in total retail revenues	$ 27,257	$ 80,717
% due to higher retail prices	76%	82%
% due to higher retail electricity sales	24%	18%

Higher retail electricity sales were principally the result of increased industrial electricity sales. We believe improving economic conditions are why some of our industrial customers experienced increased production, which resulted in more electricity sales to them. Residential and commercial electricity sales increased due primarily to the effects of warmer weather. As measured by cooling degree days, the weather during the three and nine months ended September 30, 2011, was 7% and 6%, respectively, warmer than the same periods of 2010.

Income from operations is the most directly comparable measure to gross margin that is calculated and presented in accordance with GAAP in our consolidated statements of income. Our presentation of gross margin should not be considered in isolation or as a substitute for income from operations. Additionally, our presentation of gross margin may not be comparable to similarly titled measures reported by other companies. The following table reconciles income from operations with gross margin for the three and nine months ended September 30, 2011 and 2010.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	% Change	2011	2010	Change	% Change
	(Dollars In Thousands)				(Dollars In Thousands)			
Gross margin	$ 444,725	$ 425,878	$ 18,847	4.4	$ 1,099,443	$ 1,053,909	$ 45,534	4.3
Add: SPP network transmission costs	33,887	30,682	3,205	10.4	98,623	86,746	11,877	13.7
Less: Operating and maintenance expense	137,823	126,602	11,221	8.9	412,429	369,584	42,845	11.6
Depreciation and amortization expense	72,202	67,918	4,284	6.3	213,551	201,955	11,596	5.7
Selling, general and administrative expense	27,499	50,418	(22,919)	(45.5)	132,233	144,499	(12,266)	(8.5)
Income from operations	$ 241,088	$ 211,622	$ 29,466	13.9	$ 439,853	$ 424,617	$ 15,236	3.6

Operating Expenses and Other Income and Expense Items

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	% Change	2011	2010	Change	% Change
				(Dollars In Thousands)				
Operating and maintenance expense	$ 137,823	$ 126,602	$ 11,221	8.9	$ 412,429	$ 369,584	$ 42,845	11.6

Operating and maintenance expense increased for the three and nine months ended September 30, 2011, compared to the same periods last year due principally to:

- higher SPP network transmission costs of $3.2 million and $11.9 million, respectively, most of which is recovered in revenues;

- higher costs at Wolf Creek of $3.0 million and $10.4 million, respectively, which were the result primarily of increases in the amortization of deferred refueling and maintenance outage costs of $2.9 million and $5.0 million, respectively, as well as higher regulatory compliance costs;

- higher costs for tree trimming and other distribution reliability activities of $2.2 million and $6.6 million, respectively;

increases of $3.3 million and $3.0 million, respectively, for general maintenance of our steam powered plants;

increases of $1.8 million and $4.2 million, respectively, in property taxes, which were offset in retail revenues; and

for the nine months ended September 30, 2011, our having recorded in June 2010 a $5.0 million reduction in our maximum liability for environmental remediation costs associated with assets we divested many years ago.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	% Change	2011	2010	Change	% Change
				(Dollars In Thousands)				
Depreciation and amortization expense	$ 72,202	$ 67,918	$ 4,284	6.3	$ 213,551	$ 201,955	$ 11,596	5.7

Depreciation and amortization expense increased for the three and nine months ended September 30, 2011, compared to the same periods last year as a result of our having recorded additional depreciation expense associated primarily with the addition of transmission facilities and additions at our power plants, including air quality controls.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	% Change	2011	2010	Change	% Change
				(Dollars In Thousands)				
Selling, general and administrative expense	$ 27,499	$ 50,418	$ (22,919)	(45.5)	$ 132,233	$ 144,499	$ (12,266)	(8.5)

Selling, general and administrative expense decreased for the three and nine months ended September 30, 2011, compared to the same periods last year due primarily to the reversal of approximately $22.0 million of previously accrued liabilities as a result of the legal settlements discussed in Note 9 of the Notes to Condensed Consolidated Financial Statements, Legal Proceedings. This decrease was partially offset by:

the amortization of $1.2 million and $3.0 million, respectively, of previously deferred amounts associated with various energy efficiency programs, which we recover in retail revenues; and

for the nine months ended September 30, 2011, higher legal fees of $5.5 million related principally to the legal matters discussed in Note 9 of the Notes to Condensed Consolidated Financial Statements, Legal Proceedings.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	% Change	2011	2010	Change	% Change
				(Dollars In Thousands)				
Investment earnings	$ 2,914	$ 3,248	$ (334)	(10.3)	$ 6,255	$ 4,350	$ 1,905	43.8

Investment earnings decreased for the three months ended September 30, 2011, compared to the same period last year due primarily to our having recorded losses of $4.7 million on investments in a trust to fund retirement benefits compared to recording gains on these investments of $3.2 million in 2010. This decrease was offset partially by our having recorded a $7.2 million gain on the sale of a fully impaired non-utility investment during the third quarter of 2011.

Investment earnings increased for the nine months ended September 30, 2011, compared to the same period last year due principally to our having recorded a $7.2 million gain as noted in the above paragraph. This increase was offset partially by our having recorded losses of $2.1 million on the investments discussed above during the nine months ended September 30, 2011, compared to recording gains on these investments of $2.2 million during the same period of 2010.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	% Change	2011	2010	Change	% Change
				(Dollars In Thousands)				
Other income	$ 3,404	$ 1,897	$ 1,507	79.4	$ 8,210	$ 3,792	$ 4,418	116.5

Other income increased for the three and nine months ended September 30, 2011, compared to the same periods last year due principally to:

our having recorded gains on the sale of No. 6 oil of $2.0 million and $2.5 million, respectively, for which similar gains were not recorded in 2010; and for the nine months ended September 30, 2011, a $2.5 million increase in equity AFUDC, which reflects increased construction activity.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	% Change	2011	2010	Change	% Change
				(Dollars In Thousands)				
Income tax expense	$ 61,700	$ 51,802	$ 9,898	19.1	$ 94,812	$ 86,780	$ 8,032	9.3

Income tax expense increased for the three and nine months ended September 30, 2011, compared to the same periods last year due principally to higher income before income taxes.

FINANCIAL CONDITION

Below we discuss significant balance sheet changes as of September 30, 2011, compared to December 31, 2010.

Tax receivable decreased $16.7 million, which reflects our having received $17.7 million of federal and state tax refunds.

Current deferred tax assets decreased $30.2 million due primarily to the settlements with former executive officers as discussed in Note 9 of the Notes to Condensed Consolidated Financial Statements, Legal Proceedings. Further contributing to the decrease was the Wolf Creek refueling and maintenance outage and the payment of non-union, non-executive, at-risk employee compensation related to 2010 compensation metrics.

Regulatory assets, net of regulatory liabilities, increased $47.1 million to $744.1 million at September 30, 2011, from $697.0 million at December 31, 2010. Regulatory assets increased $47.4 million due principally to the following reasons:

a $39.0 million decrease in the fair value of treasury yield hedges;

the deferral of $24.1 million of fuel expense; and

a $20.5 million increase in net amounts deferred for the Wolf Creek outage; however,

partially offsetting increases was an $11.9 million decrease in deferred employee benefit costs and amortizing $9.9 million to expense for previously deferred storm costs.

Property, plant and equipment, net, increased $317.2 million due to additions of $241.7 million at our power plants due primarily to the installation of additional air quality controls.

Short-term debt increased $165.2 million due principally to increased borrowings under Westar Energy s revolving credit facility. We used borrowings under the revolving credit facility to fund our capital and on-going operating needs.

Other current liabilities decreased $32.8 million due principally to the following reasons:

our having reached settlement agreements with former officers as discussed in Note 9 of the Notes to Condensed Consolidated Financial Statements, Legal Proceedings; and

the payment of non-union, non-executive, at-risk employee compensation related to 2010 compensation metrics; however,

partially offsetting decreases was the change in the fair value of the treasury yield hedge.

Net deferred income taxes increased $8.7 million due primarily to the recording $152.7 million of tax benefits resulting from the use of bonus and accelerated depreciation methods. Partially offsetting this increase was the tax effect of a deferred net operating loss for the current year of $90.6 million and the reversal of a valuation allowance of $51.9 million. The valuation allowance relates to state tax credit carryforwards that are now more likely than not to be realized due to a state law change which extends the state tax credit carryforward period from 10 to 16 years.

Unamortized investment tax credits increased $53.9 million due primarily to reversing $51.9 million of valuation allowances on state investment tax credits as discussed in the prior paragraph.

Accrued employee benefits decreased $50.1 million due principally to our having made payments of $50.0 million to our pension trust.

Other long-term liabilities increased $20.2 million due primarily to FERC approving a power supply agreement classified as a capital lease. See Note 14 of the Notes to Condensed Consolidated Financial Statements, Leases, for further information.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Available sources of funds to operate our business include internally generated cash, Westar Energy s revolving credit facilities and access to capital markets. We expect to meet our day-to-day cash requirements including, among other items, fuel and purchased power, dividends, interest payments, income taxes and pension contributions, using primarily internally generated cash and borrowings under the revolving credit facilities. To meet the cash requirements for our capital investments, we expect to use internally generated cash, borrowings under the revolving credit facilities and the issuance of debt and equity securities in the capital markets. We also use proceeds from the issuance of securities to repay borrowings under the revolving credit facilities, with such borrowed amounts principally related to investments in capital equipment, and for working capital and general corporate purposes. The aforementioned sources and uses of cash are similar to our historical activities. Uncertainties affecting our ability to meet cash requirements include, among others, factors affecting revenues described in Operating Results above, economic conditions, regulatory actions, compliance with environmental regulations and conditions in the capital markets.

Capital Resources

Westar Energy has two revolving credit facilities in the amounts of $730.0 million and $270.0 million, respectively, which terminate on September 29, 2016, and February 18, 2015, respectively. As long as there is no default under the facilities, each may be extended up to an additional two years and the aggregate amount of borrowings under the facilities may be increased to $1.0 billion and $400.0 million, respectively, subject to lender participation. As of October 26, 2011, $374.3 million had been borrowed and an additional $11.8 million of letters of credit had been issued under the $730.0 million facility. No amounts were borrowed and no letters of credit were issued under the $270.0 million facility as of the same date.

Common Stock

During the nine months ended September 30, 2011, Westar Energy delivered approximately 4.2 million shares of common stock as settlement of the forward sale agreement entered into in April 2010. In connection with these settlement transactions, Westar Energy received proceeds of approximately $91.9 million.

During the nine months ended September 30, 2011, Westar Energy did not deliver any shares of common stock under the forward sale agreement entered into in November 2010. Assuming physical share settlement of the approximately 8.5 million shares of common stock under this agreement at September 30, 2011, Westar Energy would have received aggregate proceeds of approximately $197.4 million based on a forward price of $23.28 per share. We expect to settle this agreement by the end of 2011.

On May 19, 2011, Westar Energy shareholders approved an amendment to its Restated Articles of Incorporation to increase the number of shares of common stock authorized to be issued from 150.0 million to 275.0 million.

Cash Flows from Operating Activities

Operating activities provided $337.8 million of cash in the nine months ended September 30, 2011, compared with cash provided of $500.4 million during the same period of 2010. The decrease was due primarily to our having paid $34.1 million more for the planned Wolf Creek refueling and maintenance outage, $31.3 million more for pension and post-retirement benefit plan contributions, $23.4 million more for purchases of natural gas for our power plants, our having received $21.9 million less in income tax refunds in 2011 and our having paid more for maintenance on our power plants and distribution system. During the nine months ended September 30, 2011, we also paid former executive officers approximately $47.9 million in compensation and paid approximately $8.4 million for their legal fees and expenses as discussed in Note 9 of the Notes to Condensed Consolidated Financial Statements, Legal Proceedings. Partially offsetting these decreases was our having received approximately $73.2 million more in customer receipts.

Cash Flows used in Investing Activities

Investing activities used $518.7 million of cash in the nine months ended September 30, 2011, compared to $388.9 million during the same period of 2010. We spent $512.7 million in the nine months ended September 30, 2011, and $369.7 million in the same period of 2010 on additions to property, plant and equipment.

Cash Flows from Financing Activities

Financing activities provided $184.6 million of cash in the nine months ended September 30, 2011, compared to using $110.8 million of cash during the same period of 2010. The increase was due primarily to our having borrowed $159.8 million under a revolving credit facility during the nine months ended September 30, 2011, compared to our having repaid $79.7 million of borrowings under the facility during the same period of 2010. We also received $68.2 million more in proceeds from the issuance of common stock due principally to the settlement of forward sale transactions during 2011. We used borrowings under the revolving credit facility to fund our capital and on-going operating needs while the proceeds from the issuance of common stock were used to repay such borrowings as well as for working capital and general corporate purposes.

Debt Covenants

We continue to be in compliance with our debt covenants.

Credit Ratings

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

In general, less favorable credit ratings make borrowing more difficult and costly. Under Westar Energy s revolving credit facilities our cost of borrowing is determined in part by credit ratings. However, Westar Energy s ability to borrow under the revolving credit facilities is not conditioned on maintaining a particular credit rating. We may enter into new credit agreements that contain credit rating conditions, which could affect our liquidity and/or our borrowing costs.

Factors that impact our credit ratings include a combination of objective and subjective criteria. Objective criteria include typical financial ratios, such as total debt to total capitalization and funds from operations to total debt, among others, future capital expenditures and our access to liquidity including committed lines of credit. Subjective criteria include such items as the quality and credibility of management, the political and regulatory environment we operate in and an assessment of our governance and risk management practices.

On May 31, 2011, Fitch upgraded its credit ratings for Westar Energy and KGE first mortgage bonds/senior secured debt to A- from BBB+. Fitch also upgraded its credit rating for Westar Energy unsecured debt to BBB+ from BBB and changed its outlook for the ratings from positive to stable. As of October 26, 2011, our ratings with the agencies are as shown in the following table.

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

Certain of our derivative instruments contain collateral provisions subject to credit agency ratings of our senior unsecured debt. If our senior unsecured debt ratings were to decrease or fall below investment grade, the counterparties to the derivative instruments, pursuant to the provisions, could require collateralization on derivative instruments. The aggregate fair value of all derivative instruments with objective credit-risk-related contingent features that were in a liability position as of September 30, 2011, and December 31, 2010, was $0.6 million and $1.6 million, respectively, for which we had posted no collateral as of September 30, 2011, or December 31, 2010. If all credit-risk-related contingent features underlying these agreements had been triggered as of September 30, 2011, and December 31, 2010, we would have been required to provide to our counterparties $0.5 million and $1.6 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

Pension Contribution

During the nine months ended September 30, 2011, we contributed $50.0 million to the Westar Energy pension trust and funded $8.6 million of Wolf Creek s pension plan contribution.

OFF-BALANCE SHEET ARRANGEMENTS

From December 31, 2010, through September 30, 2011, our off-balance sheet arrangements did not change materially. For additional information, see our 2010 Form 10-K.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

From December 31, 2010, through September 30, 2011, our contractual obligations and commercial commitments did not change materially outside the ordinary course of business. For additional information, see our 2010 Form 10-K.

OTHER INFORMATION

Changes in Prices

KCC Proceedings

On August 25, 2011, we filed an application with the KCC proposing a $90.8 million increase in our annual retail prices. The primary drivers for the proposed increase were higher costs related to tree trimming, regulatory compliance, operating Wolf Creek and employee benefits. We expect the KCC to issue an order on our request in April 2012.

On February 23, 2011, KCPL filed an application requesting that the KCC predetermine the ratemaking principles for and determine the appropriateness of approximately $1.2 billion of environmental upgrades proposed for La Cygne to comply with environmental regulations. We have a 50% interest in La Cygne and intervened in the proceeding. On August 19, 2011, the KCC issued an order ruling that the decision to make the upgrades is prudent and the $1.2 billion project cost estimate is reasonable. The KCC denied our request to collect our approximately $600.0 million share of the costs of the environmental upgrades through our ECRR. However, we requested in the application to increase retail prices noted above that we be allowed to file an abbreviated rate case within 12 months of the KCC s order in that proceeding to begin collecting costs associated with our investment.

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

On April 11, 2011, the KCC issued an order allowing us to adjust our prices, subject to final KCC review, to include updated transmission costs as reflected in our transmission formula rate discussed below. The new prices were effective April 14, 2011, and are expected to increase our annual retail revenues by approximately $17.4 million. The timing of the KCC s final order on our request is uncertain.

FERC Proceedings

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

Our transmission formula rate that includes projected 2011 transmission capital expenditures and operating costs became effective January 1, 2011, and is expected to increase our annual transmission revenues by approximately $15.9 million. This updated rate provided the basis for our request with the KCC to adjust our retail prices to include updated transmission costs as noted above.

Employees

As of October 26, 2011, we had 2,433 employees, 1,323 of which were covered under a contract with Locals 304 and 1523 of the International Brotherhood of Electrical Workers. The initial term of this contract expired June 30, 2011; however, provisions of the contract cause it to remain in force on a year-to-year basis unless either party provides a notice of termination. With neither party having provided such notice, the contract remains in effect until at least June 30, 2012. We are currently in negotiations to extend the contract.

Fair Value of Energy Marketing Contracts

The following table shows the net fair value of energy marketing contracts outstanding as of September 30, 2011.

	Fair Value of Contracts (In Thousands)
Net fair value of contracts outstanding as of December 31, 2010 (a)	$ 12,797
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	(1,577)
Changes in fair value of contracts outstanding at the beginning and end of the period	(787)
Fair value of new contracts entered into during the period	120
Net fair value of contracts outstanding as of September 30, 2011 (b)	$ 10,553

(a) Approximately $7.8 million of the fair value of energy marketing contracts was recognized as a regulatory liability.

(b) Approximately $6.6 million of the fair value of energy marketing contracts was recognized as a regulatory liability.

The sources of the fair values of the financial instruments related to these contracts and the maturity periods of the contracts as of September 30, 2011, are summarized in the following table.

		Fair Value of Contracts at End of Period			
Sources of Fair Value	Total Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity Over 5 Years
		(Dollars In Thousands)			
Prices provided by other external sources (swaps and forwards)	$ 11,435	$ 3,152	$ 7,684	$ 599	$
Prices based on option pricing models (options and other) (a)	(882)	(63)	(800)	(19)	
Total fair value of contracts outstanding	$ 10,553	$ 3,089	$ 6,884	$ 580	$

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including changes in commodity prices, counterparty credit, interest rates, and debt and equity instrument values. From December 31, 2010, to September 30, 2011, no significant changes occurred in our market risk exposure. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk in our 2010 Form 10-K for additional information.

ITEM 4. CONTROLS AND PROCEDURES

We maintain a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. In addition, the disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in reports under the Act is accumulated and communicated to management, including the chief executive officer and the chief financial officer, allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of management, including the chief executive officer and the chief financial officer, of the effectiveness of our disclosure controls and procedures, the chief executive officer and the chief financial officer have concluded that our disclosure controls and procedures were effective.

There were no changes in our internal control over financial reporting during the three months ended September 30, 2011, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information on legal proceedings is set forth in Notes 5, 8 and 9 of the Notes to Condensed Consolidated Financial Statements, Rate Matters and Regulation, Commitments and Contingencies and Legal Proceedings, respectively, which are incorporated herein by reference.

ITEM 1A. RISK FACTORS

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

We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to discharges into the air, air quality, discharges of effluents into water, water quality, the use of water, the handling, disposal and clean-up of hazardous and non-hazardous substances and wastes, natural resources, and health and safety. Compliance with these legal requirements, which change frequently and often become more restrictive, requires us to commit significant capital and operating resources toward permitting, emission fees, environmental monitoring, installation and operation of air quality control equipment and purchases of air emission allowances and/or offsets.

Costs of compliance with environmental regulations or fines or penalties resulting from non-compliance, if not recovered in our prices, could adversely affect our consolidated financial results, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increases. We cannot estimate our compliance costs or any possible fines or penalties with certainty due to our inability to predict the requirements and timing of implementation of environmental rules or regulations.

There were no other material changes in our risk factors from December 31, 2010, through September 30, 2011. For additional information, see our 2010 Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

ITEM 4. REMOVED AND RESERVED

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

4(a)	Fifty-Seventh Supplemental Indenture dated as of September 29, 2011, by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Richard Tarnas (filed as Exhibit 4.1 to the Form 8-K filed on September 29, 2011)
10(a)	Fourth Amended and Restated Credit Agreement dated as of September 29, 2011, among Westar Energy, Inc. and several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10.1 to the Form 8-K filed on September 29, 2011)
31(a)	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 certifying the quarterly report provided for the period ended September 30, 2011
31(b)	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 certifying the quarterly report provided for the period ended September 30, 2011
32	Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 certifying the quarterly report provided for the quarter ended September 30, 2011 (furnished and not to be considered filed as part of the Form 10-Q)
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

SIGNATURE

Pursuant to the requirements 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:	November 3, 2011	By:	/s/ Anthony D. Somma Anthony D. Somma
			Senior Vice President, Chief Financial Officer and Treasurer