Westar Energy®

PETER L. SUMNERS
Senior Corporate Counsel

May 31, 2011

Received
on

MAY 31 2011

by
State Corporation Commission
of Kansas

Mr. Tom Day
Acting Executive Director
Kansas Corporation Commission
1500 SW Arrowhead Road
Topeka, Kansas 66604

Re: In the Matter of Westar Energy, Inc. Compliance Filing Pursuant to Commission Order Dated December 3, 2010 in Docket No. 06-GIMX-181-GIV.

Dear Mr. Day:

Enclosed for filing please find the original and seven (7) copies of the **Compliance Filing** of Westar Energy, Inc. in the above referenced matter.

The following exhibit contains information that Westar Energy, Inc. treats as confidential, is being designated Confidential in this matter and is being filed in a separate envelope:

- Attachment B(1), (2): Organizational Chart

Please file stamp one copy for my files. Thank you for your assistance.

Sincerely,

Peter L. Sumners

Enclosures

cc: Jeff McClanahan
Adam Gatewood

818 South Kansas Avenue / P.O. Box 889 / Topeka, Kansas 66601
Telephone: (785) 575-1954 / Fax: (785) 575-8136
pete.sumners@WestarEnergy.com

2011.05.31 17:14:35
2011.05.31 17:14:35
Kansas Corporation Commission
/S/ Thomas A. Day

Received on
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by
State Corporation Commission
of Kansas

THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of Westar Energy, Inc. Compliance Filing Pursuant to Commission Order Dated December 3, 2010 In Docket No. 06-GIMX-181-GIV	))))	DOCKET NO. 11-WSEE-____-CPL

COMPLIANCE FILING

Westar Energy, Inc., Topeka, Kansas (the "Company") hereby files the following pursuant to Commission Order dated December 3, 2010 in Docket No. 06-GIMX-181-GIV and the Report of the Commission Staff and the Active Participating Utilities dated October 27, 2010 in the same docket (the "Report"):

Attachment A(1):	Westar Energy, Inc. Cost Allocation Manual
Attachment A(2):	Response
Attachment B(1), (2):	Organizational chart (Confidential)
Attachment B(3):	Descriptions of corporate personnel
Attachment B(4):	Debt instrument summaries
Attachment B(5):	Westar Energy, Inc. consolidated financial statements
Attachment B(6):	Westar Energy, Inc. financial ratios

Attachment B(1), (2) is an organizational chart containing information that Westar Energy, Inc. treats as confidential information.

Respectfully submitted,

WESTAR ENERGY, INC.

By______________________

Peter L. Sumners, #18112
Senior Corporate Counsel
818 Kansas Avenue
Topeka, Kansas 66612
(785) 575-1954; Telephone
(785) 575-8136; Fax

DATED at Topeka, Kansas, this 31st day of May, 2011.

Westar Energy, Inc. **Attachment A(1)**

Ringfencing Compliance Filing

May 31, 2011

Report requirements:

A. To ensure proper allocation or assignment of joint or common costs for non-power goods and services, so a regulated utility bears only its fair share of costs, the public utility shall submit by May 31st of each calendar year:

1. A Cost Allocation Manual (CAM) on a calendar year basis that:

- explains the methodology used for all costs allocated or assigned for non-power goods and services provided by: (a) the regulated utility, (b) a holding company, or (c) a centralized corporate services subsidiary to any associate company that is a jurisdictional public utility;

- demonstrates that all costs are allocated or assigned justly and reasonably and that the allocation or assignment of costs is not unduly discriminatory or preferential; and,

- if a fully distributed cost methodology is not used, an explanation supporting use of the alternative method of allocation.

Westar Energy Response:

A copy of the current Westar Cost Allocation Manual is hereby submitted. The Manual summary page contains a thorough explanation of the methodology followed to assure costs are allocated in a just, reasonable manner that is not unduly discriminatory or preferential. This approach to cost allocations has been reviewed by the Commission Staff numerous times in conjunction with Westar Energy, Inc. and Kansas Gas and Electric Company rate filings.

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Cost Allocation Manual

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Section:	Subject:	Effective Date:
Table of Contents		January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
None	Tim Dortch	January 1, 2012

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Cost Allocation Manual

Section:	Subject:	Effective Date:
Summary	Approach, Principles and Practices	January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
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Summary of Approach, Principles and Practices of Cost Assignment and Allocation

Westar Energy's Cost Allocation Manual (CAM) documents the process of cost allocation by Westar Energy. The approach of cost allocation utilized by Westar Energy is as follows:

- All costs should be allocated or directly assigned to the relevant jurisdiction or non-jurisdictional area whenever possible.

- Direct assignment is preferable to allocation and should be used when reasonable.[1]

- Allocations should be based upon a method which recognizes cost causation or benefits received.

- Remaining unallocated costs not directly assigned or allocated on a causal basis should be allocated on a residual factor.

- The methodology should be equitable and understandable by all interested parties.

Westar Energy's cost assignment and allocation methodology is the tool which provides for the equitable assignment and allocation of costs to jurisdictions and business units and provides assurance that cross-subsidization among jurisdictions does not occur.

The CAM incorporates the use of a three-step process and includes the following steps in order:

- Direct charging of all costs to the appropriate jurisdiction where practical.

[1] Westar Energy bills for services provided to PWT, ONEOk and WCNOC. The services provided or received are based on the terms of the contract. The services provided and the cost to provide the services are reviewed annually and revised as appropriate. Costs recovered through these service agreements are then credited back to Westar.

- Allocation of costs to jurisdictions on the basis of causal factors, where appropriate. Causal factors include such items as number of customers served, net plant etc.

- Allocation of remaining costs to jurisdiction using a residual factor. The residual factor utilized by Westar Energy is the average of the allocation factor for total customers and net plant.

Central to the CAM is an annual review, by responsibility area, of the tasks and responsibilities and the development of specific assignment and allocation process methods to be employed by each. As costs are incurred, they should be reviewed to determine if they should be directly charged or allocated.

The allocation of payroll follows the three-step process described above. Generally employees will either 1) Complete time sheets to record time for the purposes of both payroll processing and payroll allocation or 2) Review their responsibilities for allocating time. The allocation ratio for exempt employee's payroll is kept in the timekeeper's log (refer to the reference tab for an example of the Timekeepers Log). Exempt employees do not prepare time sheets since pay is based on the performance of specific responsibilities. The payroll costs for these employees are either directly assigned to a specific jurisdiction or are allocated using a predetermined allocation factor. The specific allocation factor(s) is determined through an analysis of the specific functional and jurisdictional responsibilities of each position with emphasis being placed on the cause of cost incurrence for the activities performed.[2]

Non-payroll costs are handled in much the same manner, in that they will be directly assigned or allocated to jurisdictions on the basis of the average payroll allocation factor for the responsibility area incurring the costs.

The allocation factors incorporated in this CAM and the related causal allocation methodologies for the individual responsibility areas are reviewed at least annually for continuing accuracy.

[2] Assignment and allocation of payroll includes the allocation to non-regulated or non-jurisdictional activities, for example, lobbying activities and governmental relations.

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Overview	Accounting Control Key (ACK)	January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
Allocations	Tim Dortch	January 1, 2012

Accounting Control Key (ACK)

To discuss Westar Energy's Cost Allocation process, it is helpful to first outline the Accounting Control Key (ACK). The ACK has ten different primary segments for Westar Energy's external and internal reporting requirements. They are:

BA	CC	Acct	Loc	Actv	Prod	WA	Proj	LE	DI
06920	C20	9230000	11	NOACTIV	00000	06920	00B931	01	00

Budget Area - the organizational unit that controls the resources, performs the work, controls the budget, pays the bills and bills the Work Area.

Cost Code – a code that categorizes costs (e.g., labor, material, postage, communications, etc.).

Account – accumulates cost per the FERC system of accounts.

Location – specifies the regulatory jurisdiction of the record and further specifies work area location or facility.

Activity - a descriptive code for the type of work performed.

Product – used to track revenues and expenses related to specific products or services provided. (Not currently being used)

Work Area – the organizational unit where the work was performed or who received the benefit.

Project – a Project has a finite start and end date that is normally unrelated to a calendar year, and may be Capital and/or Operation & Maintenance.

Legal Entity - used to keep Legal Entities separate, this segment is a balancing segment.

Data Indicator - used to identify records to support multiple views of information.

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All primary segments (listed on the previous page) are required to record any accounting transaction. Not all of the segments require manual input. Some segments are system generated in the originating subsystem or are generated from other segments entered as part of the transaction. The General Ledger and subsystems validate each segment as the transactions are received. In addition, the systems also validate the segments used in combination with each other.

Most transactions can be recorded directly to one account and location but some, mainly support and administrative related expenses, can be related to multiple accounts or locations (jurisdictions). Two allocations, Payroll Distribution and Jurisdiction Allocation, have been established to provide proper allocation for transactions such as these.

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Section:	Subject:	Effective Date:
Overview	Payroll Distribution Allocation	January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
None	Tim Dortch	January 1, 2012

Payroll Distribution Allocation

Westar Energy records straight-time labor in three Cost Codes: A11-Exempt Labor, A12-Hourly Fixed Distribution and A13-Hourly Variable Distribution.

The A13 labor group consists of employees who work on different project related work on a daily basis. Through the completion of daily timesheets time is charged to specific accounts, locations, activities or work requests. The A11 and A12 labor groups do not submit daily timesheets; their labor is distributed to various predetermined segments based on the results of the annual Allocation Study. The Allocation Study is completed annually as part of the budget process.

For the account distribution, a timekeeper's log containing the name and current labor distribution of every A11 and A12 employee is sent annually to each Budget Area. It is the responsibility of the area manager to review and revise the account distribution of each employee based on the employee's position and current job responsibilities. Once completed, the revised account distribution is returned to the Budget Department.

The account distribution information and the Location allocation information are provided to the Payroll Department to update the Payroll Distribution tables. When payroll is processed, the Payroll Distribution table is referenced to allocate labor expenses to the appropriate account and location for the A11 and A12 employees.

There may be a need for "exception reporting" in certain work areas. An example of this would be if a Westar Energy employee did work for ONEOK or WCNOC and needed to have their time reimbursed. Based on the ACK used, this information will be extracted from the Genral Ledger detail and billed using the monthly billing process.

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Section:	Subject:	Effective Date:
Overview	Common State Allocation	January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
None	Tim Dortch	January 1, 2012

Common State Allocation

The Common State Allocation is a process that allocates charges between Westar Energy North and Westar Energy South based on a budget area's allocation ratio. For a complete list of the budget area allocation rates and the type of allocation, refer to the Location/Jurisdictional Allocation section of the manual.

When a budget area records a charge using the common state location 00 the charge will automatically be allocated between location 11 (North) and 51 (South). This process eliminates the need to manually enter two records for one transaction.

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Section:	Subject:	Effective Date:
Overview	Wolf Creek OWO's	January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
None	Tim Dortch	January 1, 2012

Wolf Creek Owner Work Orders (OWO)

Westar Energy (WE) provides Wolf Creek Nuclear Operating Company (WCNOC) services at negotiated rates as stated in the Wolf Creek General Support Services Agreement dated January 1, 1987. The services include Accounts Payable, Insurance Services, Rubber Goods Testing, Financial and IT Services, Human Resources, IT Services, Switchyard Maintenance, and other services as needed.

Each service item has an assigned Owner Work Order (OWO). The OWO's are reviewed and negotiated annually at least nine months prior to the next contract year. The current OWO's rates are based on either an annual flat rate, cost per unit, or reimbursement of time and material.

The original expenses related to the services are first recorded on Westar Energy's books as labor, material etc. They are charged to the Westar Energy department originating the expense, using their normal expense accounts. Payment or reimbursement from WCNOC is recorded back to the originating department crediting the same originating accounts but using Cost Code R90 – Reimbursements.

For more information regarding each OWO, refer to the Wolf Creek Owner Work Orders (OWO's) section of this manual.

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Section:	Subject:	Effective Date:
Overview	ONEOK Shared Service Agreements	January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
None	Tim Dortch	January 1, 2012

ONEOK Shared Service Agreements

Westar Energy, Inc. (WE) has entered into agreements with ONEOK, Inc. (ONEOK) for operating and administrative services. For an outline of the services and rates under each agreement, refer to the ONEOK Agreement section of this manual.

Meter Reading is an example of billing based on quantity. The information for quantity based billing is tracked or reported using the system that supports the service. For example, CSS is used for number of meters read.

Another method of billing per the affiliate agreements is based on a flat rate. The flat rate for a service is based upon a predetermined expense for the service, prorated to each company based on an allocation factor.

Rates and fees charged are generally reviewed annually, but may be updated when parties agree to needed changes.

The agreements between WE and each affiliate company is outlined in their respective sections later in this manual. Each section includes an explanation of the services and the method for billing.

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Types of Allocations

Employees responsible for preparing or approving accounting records are responsible for being knowledgeable of the appropriate work area/location code.

In some transactions it is not possible to directly assign a sole jurisdiction. Therefore, an allocation rate must be used to allocate the expense between Westar Energy North and Westar Energy South. The amount to be allocated to each location can be different depending on the type of expense and the Budget Area. The allocation rates for each Budget Area are predetermined based upon information gathered in the annual review.

The annual Allocation Study includes a survey distributed to every Budget Area requiring the review of all Exempt and Fixed Distribution Hourly Employee allocations. Another part of the annual study is to update allocations for each allocation type.

In addition to the annual Allocation Study, the allocation of an Exempt or Fixed Distribution Employee is reviewed whenever there is a change in position or department. This review is part of the HR/Payroll change process.

The ratios provided below in this section are used when allocating cost to the appropriate Location (jurisdiction) when a direct charge/allocation is not possible.

The following is a brief explanation and example of the allocation types:

Gross Plant - The Gross Plant ratio includes WC and LaCygne and should be used to allocate common expenses on the basis of the company's capital investment between locations.

Location Code	Description	Percentage
11	WE North	66.58%
51	WE South	33.42%

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Net Plant in Service (w/o WC and LaCygne) – The Net Plant-in-Service allocation ratio should be used to allocate common expenses on the basis of the Company's capital investment between locations. This ratio excludes WC and LaCygne because they perform their own administrative services and financial functions.

For example, the Property Accounting Department prepares work request instructions for all areas of the Company (except WC and LaCygne). Since these work request instructions pertain to the Company's capital investment, the related expenses should be charged to all locations based on the "Total Company" (w/o WC & LaCygne) Net Plant in Service ratio.

Location Code	Description	Total Company
11	WE North	72.39%
51	WE South	27.61%

Number of Customers - The total number of Westar Energy customers allocation ratio should be used to allocate expenditures which are related to the customer distribution between locations. Customer allocation ratios are available for individual town level or for a combination of several towns or location levels.

For example - The Corporate Communications Department prepares a safety information brochure to be inserted into all customer bills. Since all customers would receive the brochure, the related expenditures should be charged to all locations based on the total company "Number of Customers" ratio.

Location Code	Description	Percentage	Customers
11	WE North	53.75%	368,847
51	WE South	46.25%	317,433

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Number of Customers and Net Plant-in-Service Residual Factor – The Residual Factor is used for almost all of the Corporate Budget Areas. The expenses incurred by the corporate areas are related to the support of assets and the customers. The residual factor is calculated by adding the percentage for Net Plant-in-Service and Number of Customers and dividing by two.

For example - The Accounts Payable Department processes payment for invoices received. The invoices are related to all areas of the company. Since the invoices are not related solely to customers, assets or employees the expenditures should be charged based on the Net Plant-in-Service and Number of Customers "Residual Factor".

Location Code	Description	Percentage
11	WE North	63.07%
51	WE South	36.93%

Several other allocations used are based on much more specific types of work.

Transmission Assets Ratio – The Transmission Assets ratio is used by groups that deal mainly with the transmission system and is based on the transmission Plant in Service by location.

Location Code	Description	Transmission Assets	Percentage
11	WE North	686,331,975	60.90%
51	WE South	440,729,783	39.10%

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Total Owned Capacity – The Total Owned Capacity ratio is used by groups that oversee the generation of all the power supplied by Westar Energy. This ratio is based on the Capacity Rating report, by plant, supplied by the Generation and Marketing area.

Location Code	Description	MW's	Percentage
11	WE North	4,245	62.78%
51	WE South	2,517	37.22%

Coal Plant Capacity – The Coal Plant Capacity ratio is used by the group that oversees the coal fired plants. This ratio is based on the Capacity Rating report supplied by the Generation and Marketing area.

Location Code	Description	MW's	Percentage
11	WE North	2,295	68.39%
51	WE South	1,141	31.61%

NOTE: These ratios are updated in January of each year. These ratios reflect 2010.

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2011 Location Splits by Work Area

Work Area	Description	NORTH %	SOUTH %	Allocation Basis
02301	Parsons	86.18	13.82	Parsons Customers
02322	Humboldt		100.00	Humboldt Customers
02352	Customer Operations-Parsons	86.18	13.82	Parsons Customers
02401	Emporia	100.00		Emporia Customers
02428	Customer Operations-Emporia	100.00		Emporia Customers
02501	Pittsburg		100.00	Pittsburg Customers
02512	Fort Scott		100.00	Fort Scott Customers
02517	Customer Operations-Pittsburg		100.00	Pittsburg Customers
02526	Customer Operations-Fort Scott		100.00	Fort Scott Customers
02640	Atchison	100.00		Atchison Customers
02672	Customer Operations-Hiawatha	100.00		Hiawatha Customers
02692	Customer Operations-Atchison	100.00		Atchison Customers
02803	Newton	7.81	92.19	Newton Customers
02843	Customer Operations-Newton	7.81	92.19	Newton Customers
02851	Ripley Yard		100.00	South Plant
02901	Hutchinson	96.03	3.97	Hutchinson Customers
02902	Cust Ops PIND-Hutchinson	96.03	3.97	Hutchinson Customers
02940	Lyons	100.00		Lyons Customers
03101	Topeka	100.00		Topeka Customers
03154	Topeka Meter Reading	100.00		Topeka Customers
03201	Manhattan	100.00		Manhattan Customers
03230	Junction City	100.00		Junction City Customers
03250	Customer Operations-Manhattan	100.00		Manhattan Customers
03260	Marysville	100.00		Marysville Customers
03301	El Dorado		100.00	El Dorado Customers
03342	Customer Operations-El Dorado		100.00	El Dorado Customers
03401	Lawrence	100.00		Lawrence Customers
03409	Customer Operations-Lawrence	100.00		Lawrence Customers
03420	Shawnee	100.00		Olathe Customers
03428	Customer Operations-Shawnee	100.00		Olathe Customers
03501	Arkansas City		100.00	Arkansas City Customers
03512	Customer Operations-Ark City		100.00	Arkansas City Customers
03550	Independence		100.00	Independence Customers
03564	Customer Operations-Independence		100.00	Independence Customers
03601	Leavenworth	100.00		Leavenworth Customers
03612	Customer Operations-Leavenworth	100.00		Leavenworth Customers
03701	Salina	100.00		Salina Customers
03730	McPherson	100.00		McPherson Customers

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2011 Location Splits by Work Area

Work Area	Description	NORTH %	SOUTH %	Allocation Basis
03742	Customer Operations-Salina	100.00		Salina Customers
03801	Abilene	100.00		Abilene Customers
05101	Central Plains Wind Farm	100.00		North Plant
05102	Flat Ridge Wind Farm	100.00		North Plant
05301	Tecumseh Energy Center	100.00		North Plant
05401	Lawrence Energy Center	100.00		North Plant
05501	Hutchinson Energy Center	100.00		North Plant
05520	Hutchinson CT's	100.00		North Plant
05601	Abilene Energy Center	100.00		North Plant
05701	Jeffrey Energy Center	78.26	21.74	JEC Capacity
05801	Planning, Modeling & Budget	53.75	46.25	Total Westar Customers
05803	Reliability Management	53.75	46.25	Total Westar Customers
05804	WMIS/Synergen	53.75	46.25	Total Westar Customers
05805	MobileData	53.75	46.25	Total Westar Customers
05807	Finance & Strategic Planning	53.75	46.25	Total Westar Customers
05810	Distribution Dispatch	53.75	46.25	Total Westar Customers
05811	Planning and Scheduleing	53.75	46.25	Total Westar Customers
05812	Substation Engineering	53.75	46.25	Total Westar Customers
05814	Design Services	53.75	46.25	Total Westar Customers
05816	Distribution Engineering Support	53.75	46.25	Total Westar Customers
05818	Technical Construction	53.75	46.25	Total Westar Customers
05821	Wichita Meter Shop	53.75	46.25	Total Westar Customers
05822	Substation & Distribution C&M	53.75	46.25	Total Westar Customers
05823	Construction Management	53.75	46.25	Total Westar Customers
05826	Standards	53.75	46.25	Total Westar Customers
05827	Transmission Engineering	53.75	46.25	Total Westar Customers
05833	Substation Construction	53.75	46.25	Total Westar Customers
05836	Trans Ops & Environmental Adm	53.75	46.25	Total Westar Customers
05837	System & Interconnect Ops Dispatch	60.90	39.10	Transmission Assets
05838	Transmission Services	60.90	39.10	Transmission Assets
05849	Commodity Risk Management	62.78	37.22	Total Owned Capacity
05850	System Planning	60.90	39.10	Transmission Assets
05853	Budgeting, Reporting & Compliance	62.78	37.22	Total Owned Capacity
05854	Wholesale Business	62.78	37.22	Total Owned Capacity
05855	Dispatch	62.78	37.22	Total Owned Capacity
05857	Power Marketing	62.78	37.22	Total Owned Capacity
05865	Real Time Operations	62.78	37.22	Total Owned Capacity
05866	EMS/SCADA	53.75	46.25	Total Westar Customers

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2011 Location Splits by Work Area

Work Area	Description	NORTH %	SOUTH %	Allocation Basis
05870	VP Generation & Marketing	77.06	22.94	Owned Capacity w/o WC or LC
05872	VP Generation	68.39	31.61	Coal Plant Capacity-JEC 100%
05873	Fuel Administration	90.00	10.00	Individual Allocation (Composite of labor distr)
05874	Generation New Construction	100.0		North Only
05875	Plant Support Engineering	65.00	35.00	Individual Allocation (Composite of labor distr)
05876	Reliability Engineering	75.00	25.00	Individual Allocation (Composite of labor distr)
05877	Safety, Training & Loss Control	63.00	37.00	Individual Allocation (Composite of labor distr)
05878	Data Management & Analysis	45.00	55.00	Individual Allocation (Composite of labor distr)
05920	Emporia Energy Center	100.00		North Plant
05930	Spring Creek Energy Center	100.00		North Plant
05940	GEEC CTF Common	100.00		North Plant
05950	Gordon Evans Energy Center		100.00	South Plant
05960	Murray Gill Energy Center		100.00	South Plant
05970	Neosho Energy Center		100.00	South Plant
05984	LaCygne Station Common		100.00	South Plant
05990	Wolf Creek		100.00	South Plant
05996	Old Sites			Individual Allocation
06002	Technical Operations	53.75	46.25	Total Westar Customers
06003	Field Communications	53.75	46.25	Total Westar Customers
06045	Mapping/GIS	72.39	27.61	Net Plant w/o WC & LC
06055	Topeka Meter Shop	53.75	46.25	Total Westar Customers
06056	Smart Grid	53.75	46.25	Total Westar Customers
06101	District Field Ops Admin	53.75	46.25	Total Westar Customers
06200	Vegetation Management	53.00	47.00	Individual Allocation (Composite of labor distr)
06201	Resource Management Electric	53.75	46.25	Total Westar Customers
06202	Public Affairs Administration	53.75	46.25	Total Westar Customers
06205	Storms-Other Utility Assistance			
06206	Community Affairs	53.80	46.20	Total Westar Customers
06210	Customer Service Admin	53.80	46.20	Total Westar Customers
06215	VP Operations Strategy & Supp	63.07	36.93	Residual Factor
06218	Aviation	63.07	36.93	Residual Factor
06305	Customer & Community Relations - North Region	53.75	46.25	Total Westar Customers
06309	Customer & Community Relations - South Region	53.75	46.25	Total Westar Customers
06310	Energy Efficiency	53.75	46.25	Total Westar Customers
06311	Biology & Conservation Programs	53.75	46.25	Total Westar Customers
06321	Wichita Metro		100.00	Total Wichita Customers

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2011 Location Splits by Work Area

Work Area	Description	NORTH %	SOUTH %	Allocation Basis
06330	Customer & Community Relations Admin	53.75	46.25	Total Westar Customers
06331	Wichita Billing Services	53.75	46.25	Total Westar Customers
06332	Customer Information	53.75	46.25	Total Westar Customers
06333	Customer Contact Center	53.75	46.25	Total Westar Customers
06336	Wichita Services		100.00	South Only
06337	Credit Card and Collections Adm	53.75	46.25	Total Westar Customers
06338	Customer Advisor	53.75	46.25	Total Westar Customers
06402	Power Delivery Administration	53.75	46.25	Total Westar Customers
06403	Power Delivery Reliability & Scheduling	53.75	46.25	Total Westar Customers
06502	Government Affairs	63.07	36.93	Residual Factor
06504	Media Relations	63.07	36.93	Residual Factor
06601	Human Resources Management	63.07	36.93	Residual Factor
06602	Employee Benefits	63.07	36.93	Residual Factor
06603	Organizational Dev & Training	63.07	36.93	Residual Factor
06604	Labor Relations	63.07	36.93	Residual Factor
06605	Safety & Compliance	63.07	36.93	Residual Factor
06606	Environmental Services Staff	63.07	36.93	Residual Factor
06612	Employment	63.07	36.93	Residual Factor
06613	Compensation	63.07	36.93	Residual Factor
06614	H.R.I.S.	63.07	36.93	Residual Factor
06615	Benefits Accounting	63.07	36.93	Residual Factor
06616	EEO	63.07	36.93	Residual Factor
06701	Legal Dept Corporate	63.07	36.93	Residual Factor
06702	General Legal	63.07	36.93	Residual Factor
06703	Legal - Admin	63.07	36.93	Residual Factor
06705	Rev Prot & Recovery Claims	53.75	46.25	Total Westar Customers
06780	Supply Chain Admin	63.07	36.93	Residual Factor
06781	Strategic Sourcing & Alliance Management	63.07	36.93	Residual Factor
06802	Facilities Management	63.07	36.93	Residual Factor
06803	Procurement Services	63.07	36.93	Residual Factor
06804	Inventory & Distribution	63.07	36.93	Residual Factor
06806	Fleet Admin	62.00	38.00	Fleet Admin Ratio
06807	Facilities Services	63.07	36.93	Residual Factor
06810	Mail Processing	53.75	46.25	Total Westar Customers
06812	Facility Administration Costs	53.75	46.25	Total Westar Customers
06813	Project Services	63.07	36.93	Residual Factor
06814	Real Estate Services	63.07	36.93	Residual Factor

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Section:	Subject:	Effective Date:
Location/Jurisdictional Allocations	Current Allocation Ratios	January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
	Tim Dortch	January 1, 2012

2011 Location Splits by Work Area

Work Area	Description	NORTH %	SOUTH %	Allocation Basis
06815	Facilities Security Services	63.07	36.93	Residual Factor
06816	Fleet Operations Electric			Individual Allocation
06817	Safety/Training	53.75	46.25	Total Westar Customers
06821	Wichita Distribution	3.50	96.50	Individual Allocation (Composite of labor distr)
06822	Topeka Distribution	100.00		North Only
06825	Wichita Fleet Garage	2.06	97.94	Wichita Fleet Garage Ratio
06827	Topeka Fleet Garage	90.00	10.00	Topeka Fleet Garage Ratio
06834	IT Management Staff	63.07	36.93	Residual Factor
06835	IT Account Managers	63.07	36.93	Residual Factor
06890	Facility Operating Costs	63.07	36.93	Residual Factor
06920	Controller Staff	63.07	36.93	Residual Factor
06921	Budget & Performance Reporting	63.07	36.93	Residual Factor
06922	Corporate Tax	63.07	36.93	Residual Factor
06924	SEC Reporting	63.07	36.93	Residual Factor
06926	Accounts Payable	63.07	36.93	Residual Factor
06927	Payroll	63.07	36.93	Residual Factor
06928	Asset Management	72.39	27.61	Net Plant w/o WC & LC
06929	Billing Services	53.75	46.25	Total Westar Customers
06930	Financial Accounting	63.07	36.93	Residual Factor
06931	Power Marketing Accounting	63.07	36.93	Residual Factor
06939	Shareholder Services	66.58	33.42	Net Plant including WC & LC
06940	Remittance Proc-Topeka	53.75	46.25	Total Westar Customers
06941	Treasury-Revenue Only	63.07	36.93	Residual Factor
06943	Cash Management	63.07	36.93	Residual Factor
06945	Investor Relations	66.58	33.42	Net Plant including WC & LC
06946	Chief Financial Officer Staff	63.07	36.93	Residual Factor
06947	Finance Staff	63.07	36.93	Net Plant including WC & LC
06949	IT Lotus Notes Developer	63.07	36.93	Residual Factor
06950	IT Administration	63.07	36.93	Residual Factor
06951	Power Delivery Appl	63.07	36.93	Residual Factor
06952	Customer Services Appl	63.07	36.93	Residual Factor
06953	IT Security	63.07	36.93	Residual Factor
06954	Financial Applications	63.07	36.93	Residual Factor
06955	DB Administration	63.07	36.93	Residual Factor
06957	IT Payroll/HR App Dev	63.07	36.93	Residual Factor
06958	IT Process Improvement	63.07	36.93	Residual Factor
06959	IT System Infrastructure	63.07	36.93	Residual Factor
06960	Technology Enablement	63.07	36.93	Residual Factor

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Location/Jurisdictional Allocations	Current Allocation Ratios	January 1, 2011
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2011 Location Splits by Work Area

Work Area	Description	NORTH %	SOUTH %	Allocation Basis
06961	PC/Printer Admin & Support	63.07	36.93	Residual Factor
06962	Database Administration-IT	63.07	36.93	Residual Factor
06963	Voice Systems	53.75	46.25	Total Westar Customers
06964	IT Generation & Marketing Support	63.07	36.93	Residual Factor
06965	Treasury Fidelity Express	63.07	36.93	Residual Factor
06966	Genco Tech Support - IT Group	63.07	36.93	Residual Factor
06967	IT Enterprise Architecture	63.07	36.93	Residual Factor
06968	IT Audio/Video Support	63.07	36.93	Residual Factor
06969	IT Special Initiatives	63.07	36.93	Residual Factor
06970	Regulatory Affairs	53.75	46.25	Total Westar Customers
06971	Treasury Bill Matrix (CR & DB Cards)	63.07	36.93	Residual Factor
06972	Regulatory Compliance	63.07	36.93	Residual Factor
06990	Corporate Compliance & Internal Audit	63.07	36.93	Residual Factor
08005	Credit and Collections	53.75	46.25	Total Westar Customers
08101	General Administration	63.07	36.93	Residual Factor
08126	Benefits	63.07	36.93	Residual Factor

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Section:	Subject:	Effective Date:
ONEOK	Contracts	January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
	Tim Dortch	January 1, 2012

Shared Services Agreement between
Westar Energy, Inc. and ONEOK, Inc.

Services Provided

In November 1997, WE and ONEOK entered into a Shared Services Agreement to perform services for each other as stated in the Shared Services Agreement and the schedules of the agreement. Most of the original schedules were discontinued in September 2004. The following schedules are the active schedules in the agreement. The schedules are reviewed and revised annually.

Schedule 3.11 (ONEOK provides to WE)

Meter reading
Description: The provider will be responsible for reading meters and providing back-up meter readers if the need arises.

Billing: See Attachment A (page 6)

Schedule 3.12 (WE provides to KGS)

Meter reading
Description: The provider will be responsible for reading meters and providing back-up meter readers if the need arises.

Billing: See Attachment A (page 6)

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ONEOK	Contracts	January 1, 2011
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	Tim Dortch	January 1, 2012

Schedule 3.13 (ONEOK provides to WE)

Stores operations
Description: ONEOK provides WE with storeroom operation services in Emporia.

Billing: Billing is based upon a flat annual rate. See Attachment A (page 6)

Schedule 3.14 (WE provides to ONEOK)

Stores operations
Description: WE provides ONEOK with storeroom operation services in Atchison, Manhattan, Marysville, Leavenworth, Salina

Billing: Billing is based upon a flat annual rate. See Attachment A (page 6)

Schedule 3.19 (Services provided by both WE and ONEOK)

Data & Voice network provided to ONEOK
Description: WE provides data and voice network to ONEOK in shared facilities.

Billing: See Attachment A (page 6)

Costs are determined based on the percent of the network ONEOK uses. These costs and percentages are reviewed annually and are agreed to by both WE and ONEOK. The Information Technology (IT) group provides these costs.

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ONEOK	Contracts	January 1, 2011
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Campus Fiber network provided to ONEOK
Description: WE provides campus fiber network to ONEOK in shared facilities.

Billing: See Attachment A (page 6)

Costs are determined based on the percent of the network ONEOK uses. These costs and percentages are reviewed annually and are agreed to by both WE and ONEOK. The IT group provides these costs.

Data network services provided to WE
Description: ONEOK provides data network services to WE in shared facilities.

Billing: See Attachment A (page 6)

Costs are determined based on the percent of the network WE uses. These costs and percentages are reviewed annually and are agreed to by both WE and ONEOK. The IT group provides these costs.

Special Billing

Occasionally, both WE and ONEOK may have incurred additional expenses that need to be passed on to the other company. Representatives of both companies agree upon these expenses, and the charges are then passed on to the appropriate company.

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ONEOK	Contracts	January 1, 2011
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Shared Facilities

WE and ONEOK originally entered into a 5-year contract regarding shared facilities. The contract expired November 30, 2002. WE and ONEOK have renegotiated shared facilities on a year by year basis. The following schedule outlines the shared facilities costs for the 2011 contract year:

ONEOK Owned Shared Facilities

Contract Price: $232,366 annually

Location	Address	Space (sq/ft)		Annual Cost
Atchinson	812 Main St.	5,055		$ 43,720
Emporia	220 Mechanic	6,414		$ 52,494
Hiawatha	1701 Oregon	2,609		$ 33,594
Salina	1001 Edison Pl.	11,098		$ 102,558
			Total	$ 232,366

Westar Energy Owned Shared Facilities

Contract Price: $225,930 annually

Location	Address	Space (sq/ft)		Annual Cost
Ark City	3113 Summit	4,975		$ 42,210
El Dorado	700 N. Star	7,124		$ 56.614
Leavenworth	2720 2nd Ave.	7,151		$ 62,506
Manhattan	225 Seth Childs	4,514		$ 46,914
Marysville	301 N. 8th	1,436		$ 11,656
Seneca	1204 Main	505		$ 3,030
			Total	$ 225,930

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Section:	Subject:	Effective Date:
ONEOK	Contracts	January 1, 2011
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	Tim Dortch	January 1, 2012

Cost Allocation Process

Services provided by WE to ONEOK are reimbursed back against where the charge originated from. The cost code used to designate reimbursements from ONEOK is "R50." The following is an example of how the reimbursement process works.

WE provides meter reading to ONEOK in Topeka.
Where charge originates: 03154 – A12 - 9020005 – 11 - $50.00
Reimbursement: 03154 – R50 – 9020005 – 11 – ($50.00)
Receivable from ONEOK: 08160 – Z99 – 1431802 – 11 - $50.00

Services provided by ONEOK to WE are charged to where the charge would have originated if WE did the work itself. The cost code used to designate expenses from KGS is "C50." The following is an example of how this would be expensed:

ONEOK provided meter reading to WE in Hutchinson.
Where the expense is booked: 02901 – C50 – 9020005 – 11 - $50.00
Payable to ONEOK: 08160 – Z99 – 1431803 – 11 – ($50.00)

Transfer of Cash

The net amount that is owed is wired every three months. The cash is required to be wired within 10 days of receiving the invoice with the prior three months worth of activity.

Section:	Subject:	Effective Date:
ONEOK	Contracts	January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
	Tim Dortch	January 1, 2012

ATTACHMENT A
Rates to the Westar Energy/ONEOK Shared Service Agreements

Effective Date: December 1, 2010 to November 30, 2011

Schedule 3.11:	$0.42 per meter read
Schedule 3.12:	$0.42 per meter read
Schedule 3.13:	$42,548 per year
Schedule 3.14:	$81,623 per year
Schedule 3.19:	Data and Voice billed to ONEOK: $2,278.84 per month Sonet billed to ONEOK: $1,427.27 per month Campus Fiber billed to ONEOK: $120.00 per month Data Network billed to WE: $1,287.70 per month
Facilities:	Facilities lease billed to ONEOK: $18,827.50 per month Facilities lease billed to WE: $19,363.83 per month

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Section:	Subject:	Effective Date:
Affiliate Billing		January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
Wolf Creek OWO's	Tim Dortch	January 1, 2012

Wolf Creek Owner Work Orders

Services Provided

Westar Energy provides Wolf Creek with services at negotiated rates as stated in the Wolf Creek General Support Services Agreement and the following owner work orders (OWO's):

OWO: 0707708 – Insurance Services
OWO: 0706745 – Rubber Goods Testing
OWO: 0590107 – Computer Leases (no activity)
OWO: 0701770 – Accounts Payable Services
OWO: 0701771 – Information Technology Services & Financial Services
OWO: 0701772 – Information Technology Services & H.R. Services

Other OWO's as issued

General Support Agreement – Switchyard Maintenance – labor and overheads

Other items related to Wolf Creek are billed as well. These include, but are not limited to, employee expenses, oil testing charges, and water protection fees.

The following will provide additional billing information for the above stated OWO's.

OWO: 0707708 – Insurance Services

Description: Westar Energy will provide the administration of WCNOC property and liability insurance requirements.

Billing: $54,333/year

The current rates are based on Westar Energy's cost to provide the service in 2010. The OWO is reviewed and negotiated annually.

OWO: 0706745 – Rubber Goods Testing

Description: Westar Energy will provide testing of electrical safety equipment in accordance with approved OSHA requirements. Test results shall accompany rubber goods shipment.

Billing: Testing of rubber gloves: $5/pair tested
Testing of blankets: $12/each
Testing of Sleeves: $8/pair

Counts of rubber goods are supplied by Westar Energy's Standards department.

The current rates are based upon Westar Energy's cost to provide the service in 2010. Rubber goods testing has remained the same. The OWO is reviewed and negotiated annually.

OWO: 0701770 – Accounts Payable Services

Description: Westar Energy will provide various accounts payable check processing services to WCNOC.

Billing: $3.62/Check generation
$3.53/ Check canceled and reissued
$4.71/Check and invoice canceled
$2.36/Canceled invoice
$3.88/Manual check
$1.29/Attachments
$3.88/Wire transfers
$4.39/Entry of invoices
$4.43/1099 processing
$0.65/Special handling (folding)
$1.29/Research

$0.03/Envelope

The current rates are based upon Westar Energy's cost to provide the service in 2010. The OWO is reviewed and negotiated annually.

OWO: 0701771 – Information Technology Services & Financial Services

Description: Westar Energy will provide certain general ledger processing services (WALKER) to WCNOC.

Billing: IT related general ledger processing services: $45,027/year.
Financial services related general ledger processing services: $3,314/year.

The current rates are based upon Westar Energy's cost to provide the service in 2010. The amount billed has been adjusted to reflect the results of an audit performed by the owners during the end of 2009. The OWO is reviewed and negotiated annually.

OWO: 0701772 – Information Technology Services & H.R. Services

Description: Westar Energy will provide certain human resources processing services to WCNOC.

Billing: IT PeopleSoft services: $246,405/year
Payroll/mail room services: $141,600/year
HRIS/Benefits Accounting/Benefits Admin: $180,932/year

The current rates are based upon Westar Energy's cost to provide the service in 2010. The OWO is reviewed and negotiated annually.

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Affiliate Billing		January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
Wolf Creek OWO's	Tim Dortch	January 1, 2012

Cost Allocation Process

All billable items including Switchyard Maintenance labor charges, OWO charges, and other expenses are reimbursed back to the work area where the expense originated. Wolf Creek then books these expenses on their books once they receive the monthly bill from Westar.

Expenses that are to be billed to Wolf Creek are identified by using 05990 in the Work Area. This allows accounting to pick up the expenses and pass them on to Wolf Creek.

All expenses that can be passed on to Wolf Creek are reimbursed on Westar Energy's books. These reimbursements are designated by cost code "R90."

Transfer of Cash

Wolf Creek does not wire any cash to Westar Energy for payment of the above listed services and expenses. Instead, the amount Wolf Creek owes Westar Energy is netted against Westar Energy's payable account to Wolf Creek. The amount Westar Energy wires Wolf Creek is reduced by the amount Wolf Creek owes Westar Energy.

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Section:	Subject:	Effective Date:
Non Regulated Labor		January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
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Non-Regulated Labor: Account 4265XXX

Below is a list of budget areas that currently have employees allocating a portion of their time to non-regulated expense.

BA: 06920 Controller
BA: 06931 Power Accounting
BA: 05849 Risk Management
BA: 05857 Power Marketing
BA: 05865 Real Time Operations

All other non-regulated labor is recorded monthly in account 426.50.

Non-regulated labor performed by exempt employees is prorated based on the hours available per month. See the following example:

Employee Z worked 200 hours in a month
Employee Z earns $20/hr
20 hours are designated non-regulated
There are 168 hours available in the month
16.8 hours would be reclassed as non-regulated labor
(20hrs / 200 hrs) x (168hrs)
$336 would be reclassed for labor ($20 x 16.8hrs)
$148 would be reclassed for pension/benefits/payroll taxes ($336 x 44%)

Non-regulated labor performed by hourly employees is recorded based on actual hours reported as non-regulated on the employee's time tickets.

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Section:	Subject:	Effective Date:
Westar Generating Labor		January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
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Westar Energy (WE) Labor Provided to Westar Generating (Stateline)

Services Provided

Westar Energy (WE) provides support to Westar Generating. The support provided includes: Accounting, Regulatory, Legal, Generation and System Load and Dispatch.

Cost Allocation Process

Costs that need to be charged to Westar Generating from WE are gathered from two different sources. Accounting labor is gathered from reports generated in Activity Tracking. Legal and Regulatory labor is manually tracked and gathered by the Legal and Regulatory departments. All other labor is based on a percentage that is determined by Generation Services.

When labor is charges by WE to Westar Generating, the FERC accounts in which the labor expense originated is credited and the labor is expensed on Westar Generating's books as subcontract labor. In addition to labor and the applicable payroll tax and benefits loadings at are charged, an A&G loading on labor is charged as well. This amount, being the A&G loading is included in the subcontract labor on Westar Generating's books, and is credited to account 9302008 (Other Misc. General Expenses) on WE's books.

Transfer of Cash

There is no transfer of cash between WE and Westar Generating.

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Section:	Subject:	Effective Date:
Prairie Wind Transmission		January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
	Tim Dortch	January 1, 2012

Prairie Wind Transmission

Services Provided

Westar Energy (WE) employees provide support services to the Prairie Wind Transmission (PWT) project. Employees in the following departments have charged time and incurred expenses in support of the PWT project: Transmission Construction and Engineering, Legal, Finance, Accounting, Treasury, Regulatory, Customer Care, Governmental, Community Affairs, Conservation, Substation and Distribution, Major Construction, Supply Chain and Media Relations.

Cost Allocation Process

Employee time and vehicle hours are reported in the Activity Tracking System (ATS) that are billable to PWT. The actual invoiced amount to PWT is the billable hours times the appropriate rate plus labor loadings. Expenses other than employee time and vehicle hours are charged to account 1461023 and billed to PWT.

Monthly, the Westar Accounting Department books a journal entry that credits Westar expenses and sets up an accounts receivable from Prairie Wind Transmission based on the billable data from ATS and account 1461023.

Transfer of Cash

The accounting department presents a monthly invoice to the Westar treasury department who initiates a payment from PWT in the form of a wire transfer.

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Section:	Subject:	Effective Date:
Activity Tracking		January 1, 2011
Sub Section:	**Approved By:**	**Next Review Date:**
None	Tim Dortch	January 1, 2012

Activity Tracking

The activity tracking system was developed to allow employees with fixed distribution to charge/track time spent on projects outside their normal distribution. Billable hours are identified at the end of each month and a journal entry is made to bill the associated costs.

Using Activity Tracking

To log in to the Activity Tracking System, enter in your Web Browser the following address, **http://ats/ATSasp/login.asp**

Enter your **User ID.** This is the five-digit number on your ID card.
Enter the **Password**. This is currently defaulted to **Westar**. Click on **LOGIN**.
Note: At this screen you can change the defaulted password, if you choose.

The following screen will appear:

Activity Tracking System Home

Employee: [Empl Number] [Name]
Week Begins: Retrieve Submit Save as Default Replace with Default

Select the week for which you need to enter time.

Click on **Retrieve** and the following will appear.

Customer	Product	Project	Other	Sun	Mon	Tue	Wed	Thu	Fri	Sat	Total
											0.0

Click on **"Replace with Default",** then OK. A pre-established set of project rows will appear.

Recording your Hours Worked

Click in the cell below the day of the week you are recording your hours for. Time should be recorded to the nearest half hour (i.e. 7.5). To the right of "Total", you can enter comments to further define the work.

SAVE your worksheet. After you have **SAVED** hours for the week, you can still add hours later on.

SUBMIT - When you are finished entering hours for the week, you must hit **SUBMIT** in order for your hours to be reported. Once this has been done, you will not be able to change the information for the week.

Timekeepers Log

Emp ID	Name	BA	Paygro	job code	Title	Position	%	Cost Code	Account	Loc	Activity	Product	WA	Project	Work Req	Equip	User Cd
8655	LaForge,Deborah Sue	2301	WRE	10073	Electric Distribution Supv	1294	10	A11	5900000	11			2301				
8655	LaForge,Deborah Sue	2301	WRE	10073	Electric Distribution Supv	1294	15	A11	5830000	11			2301	00B524			
8655	LaForge,Deborah Sue	2301	WRE	10073	Electric Distribution Supv	1294	75	A11	1847100	11			2301				
16226	Bledsoe II,Hazen P	2401	WRE	10073	Electric Distribution Supv	1295	5	A11	5900000	11			2401				
16226	Bledsoe II,Hazen P	2401	WRE	10073	Electric Distribution Supv	1295	5	A11	5830000	11			2401	00B524			
16226	Bledsoe II,Hazen P	2401	WRE	10073	Electric Distribution Supv	1295	5	A11	5680000	11			2401				
16226	Bledsoe II,Hazen P	2401	WRE	10073	Electric Distribution Supv	1295	15	A11	5600001	11			2401				
16226	Bledsoe II,Hazen P	2401	WRE	10073	Electric Distribution Supv	1295	70	A11	1847100	11			2401				
9712	Heins Jr,William H	2401	WRE	10016	Director, Division Operation	1316	5	A11	5830000	11			2401	00B524			
9712	Heins Jr,William H	2401	WRE	10016	Director, Division Operation	1316	5	A11	5800000	11			2401				
9712	Heins Jr,William H	2401	WRE	10016	Director, Division Operation	1316	10	A11	5900000	11			2401				
9712	Heins Jr,William H	2401	WRE	10016	Director, Division Operation	1316	10	A11	5680000	11			2401				
9712	Heins Jr,William H	2401	WRE	10016	Director, Division Operation	1316	10	A11	5600001	11			2401				
9712	Heins Jr,William H	2401	WRE	10016	Director, Division Operation	1316	60	A11	1847100	11			2401				
1783	Peterson,Naomi I	2401	WRE	26710	Electric Distrib Supv - Desigr	8137	77	A11	1847100	11			2401				
1783	Peterson,Naomi I	2401	WRE	26710	Electric Distrib Supv - Desigr	8137	15	A11	5830000	11			2401				
1783	Peterson,Naomi I	2401	WRE	26710	Electric Distrib Supv - Desigr	8137	8	A11	5900000	11			2401				
4827	Stegmaier,Aaron P	2401	WRE	10073	Electric Distribution Supv	370	8	A11	5900000	11			2401				
4827	Stegmaier,Aaron P	2401	WRE	10073	Electric Distribution Supv	370	15	A11	5830000	11			2401	00B524			
4827	Stegmaier,Aaron P	2401	WRE	10073	Electric Distribution Supv	370	77	A11	1847100	11			2401				
4947	Trahoon II,Rolland E	2401	WRE	10073	Electric Distribution Supv	1295	5	A11	5900000	11			2401				
4947	Trahoon II,Rolland E	2401	WRE	10073	Electric Distribution Supv	1295	5	A11	5830000	11			2401	00B524			
4947	Trahoon II,Rolland E	2401	WRE	10073	Electric Distribution Supv	1295	5	A11	5680000	11			2401				
4947	Trahoon II,Rolland E	2401	WRE	10073	Electric Distribution Supv	1295	15	A11	5600001	11			2401				
4947	Trahoon II,Rolland E	2401	WRE	10073	Electric Distribution Supv	1295	70	A11	1847100	11			2401				
27117	Willis,David M	2501	WRE	10073	Electric Distribution Supv	2379	5	A11	5830000	51			2501	00B524			
27117	Willis,David M	2501	WRE	10073	Electric Distribution Supv	2379	10	A11	5900000	51			2501				
27117	Willis,David M	2501	WRE	10073	Electric Distribution Supv	2379	10	A11	5800000	51			2501				
27117	Willis,David M	2501	WRE	10073	Electric Distribution Supv	2379	75	A11	1847100	51			2501				
6071	Sackett,James	2526	WRE	373	Supervisor, Customer Servic	2326	20	A11	9020002	51			2526				
6071	Sackett,James	2526	WRE	373	Supervisor, Customer Servic	2326	20	A11	9020005	51			2526				
6071	Sackett,James	2526	WRE	373	Supervisor, Customer Servic	2326	40	A11	5860001	51			2526				
6071	Sackett,James	2526	WRE	373	Supervisor, Customer Servic	2326	20	A11	9030002	51			2526				
9885	Hargrove,Edwin C	2640	WRE	10073	Electric Distribution Supv	1297	5	A11	5680000	11			2640	00B940			
9885	Hargrove,Edwin C	2640	WRE	10073	Electric Distribution Supv	1297	5	A11	5600001	11			2640	00B940			
9885	Hargrove,Edwin C	2640	WRE	10073	Electric Distribution Supv	1297	10	A11	5900000	11			2640	00B940			
9885	Hargrove,Edwin C	2640	WRE	10073	Electric Distribution Supv	1297	10	A11	5800000	11			2640	00B940			
9885	Hargrove,Edwin C	2640	WRE	10073	Electric Distribution Supv	1297	70	A11	1847100	11			2640	00B905			
27955	Whitley,Robert M	2803	WRE	10073	Electric Distribution Supv	2380	5	A11	5680001	51			2803				
27955	Whitley,Robert M	2803	WRE	10073	Electric Distribution Supv	2380	5	A11	5600000	51			2803				
27955	Whitley,Robert M	2803	WRE	10073	Electric Distribution Supv	2380	15	A11	5900000	51			2803				

Westar Energy, Inc. **Attachment A(2)**

Ringfencing Compliance Filing

May 31, 2011

Report requirements:

2. Any centralized corporate services subsidiary, within a holding company that includes a jurisdictional public utility, required to file FERC Form No. 60, shall file a copy with the Commission by May 31st of the calendar year following the year subject of the report.

Westar Energy Response:

Neither Westar Energy, Inc. nor any of its subsidiaries is required to file a FERC Form No. 60.

Westar Energy, Inc. **Attachment B(3)**

Ringfencing Compliance Filing

May 31, 2011

Report requirements:

B. Each jurisdictional public utility shall provide annually by May 31st the following information using diagrams, schedules or narrative discussion as may be appropriate:

3. An organizational chart of personnel that includes a list of all directors, corporate officers, and other key personnel shared by any jurisdictional public utility and any non-utility associate company or holding company, if any, along with a description of each person's duties and responsibilities to each entity;

Westar Energy Response:

A responsive list is attached. The roles and responsibilities of the board of directors and its committees are addressed in the Westar Energy, Inc. proxy statement filed annually with the Securities and Exchange Commission.

CORPORATE PERSONNEL

Westar Energy, Inc.
(f/k/a Western Resources, Inc., f/k/a The Kansas Power and Light Company)

Directors:

Mollie Hale Carter
Charles Q. Chandler, IV, Chairman
R.A. Edwards III
Jerry B. Farley
B. Anthony Isaac
Arthur B. Krause
Sandra A.J. Lawrence
William B. Moore
Michael F. Morrissey
Mark A. Ruelle
S. Carl Soderstrom, Jr.

Officers:

Chief Executive Officer, William B. Moore
Responsible for general supervision and management of the company's overall business.

President and Chief Financial Officer, Mark A. Ruelle
Responsible general supervision and management of the company's accounting, finance, human resources, information technology, risk management and major construction departments. Assists the Chief Executive Officer with general supervision and management of the company's overall business.

Executive Vice President and Chief Operating Officer, Douglas R. Sterbenz
Responsible for general supervision and management of the company's generation, construction and maintenance, distribution and power delivery, environmental, facilities, strategic planning, operations strategy and support, power marketing, safety training, supply chain and transmission departments.

Executive Vice President, Public Affairs and Consumer Services, James J. Ludwig
Responsible for general supervision and management of the company's customer care, community affairs, energy efficiency, and public and governmental affairs departments.

Vice President, Controller and Assistant Secretary, Leroy P. Wages
Responsible for supervision and day-to-day management of the company's accounting department.

Vice President, General Counsel, Corporate Secretary, Larry D. Irick
Responsible for supervision and day-to-day management of the company's legal department.

Vice President, Regulatory Affairs, C. Michael Lennen
Responsible for supervision and day-to-day management of the company's regulatory affairs department.

Vice President, Corporate Compliance and Internal Audit, Jeffrey L. Beasley
Responsible for supervision and day-to-day management of the company's corporate compliance and internal audit department

Vice President, Customer Care, Peggy S. Ricketts
Responsible for supervision and day-to-day management of the company's customer care department.

Vice President, Distribution Power Delivery, Caroline A. Williams
Responsible for supervision and day-to-day management of the company's distribution and power delivery department.

Vice President, Generation, John T. Bridson
Responsible for supervision and day-to-day management of the company's generation department.

Vice President, Human Resources, Jerl L. Banning
Responsible for supervision and day-to-day management of the company's human resources department.

Westar Energy, Inc. (cont'd)
(f/k/a Western Resources, Inc., f/k/a The Kansas Power and Light Company)

Vice President, Major Construction Projects, Gregory A. Greenwood
Responsible for supervision and day-to-day management of the company's major construction department.
Vice President, Operations Strategy and Support, Bruce A. Akin
Responsible for supervision and day-to-day management of the company's operations strategy and support department.
Vice President, Transmission Operations & Environmental Services, Kelly B. Harrison
Responsible for supervision and day-to-day management of the company's transmission operations and environmental departments.
Vice President and Treasurer, Anthony D. Somma
Responsible for supervision and day-to-day management of the company's treasury department.
Assistant Treasurer, Carolyn A. Starkey
Responsible for support of the Vice President and Treasurer and various related management and treasury functions.
Assistant Controller, Kevin L. Kongs
Responsible for support of the Vice President and Controller and various related accounting functions.

Kansas Gas and Electric Company
(f/k/a KCA Corporation)

Directors:

William B. Moore, Chair
Douglas R. Sterbenz
Caroline A. Williams

Officers:

President, William B. Moore
Responsible for general supervision and management of the company's overall business.
Vice President, Caroline A. Williams
Assists the President with general supervision and management of the company's overall business, particularly with regard to distribution and power delivery functions.
Vice President, John T. Bridson
Assists the President with general supervision and management of the company's overall business, particularly with regard to generation and certain finance functions.
Vice President, Kelly B. Harrison
Assists the President with general supervision and management of the company's overall business, particularly with regard to transmission operations, environmental, and certain finance functions.
Vice President & Treasurer, Mark A. Ruelle
Assists the President with general supervision and management of the company's overall business, particularly with regard to finance and treasury functions.
Secretary, Larry D. Irick
Responsible for supervision and day-to-day management of legal and certain finance functions; responsible for duties consistent with those of a corporate secretary.
Assistant Treasurer, Anthony D. Somma
Responsible for support of the Vice President and Treasurer and certain finance functions.

Westar Energy, Inc. **Attachment B(4)**

Ringfencing Compliance Filing

May 31, 2011

Report requirements:

B. Each jurisdictional public utility shall provide annually by May 31st the following information using diagrams, schedules or narrative discussion as may be appropriate:

4. Summaries of each mortgage, loan document and debt agreement including a discussion of the type of collateral or security pledged to support the debt. The utility will also describe any loan or debt agreement taken out to finance an unregulated affiliate that encumbers utility property or cash-flow for security;

Westar Energy Response:

Responsive summaries are attached.

Westar Energy

Legal Structure for Debt Offerings

<u>1939 Mortgage</u>

41 supplemental indentures

Parent

Westar Energy, Inc. (WEI)

<u>1940 Mortgage</u>

56 supplemental indentures

Subsidiary

Kansas Gas and Electric Company (KGE)

Westar Energy.

Westar Energy, Inc. Mortgage

From time to time, Westar Energy, Inc. ("WEI") issues first mortgage bonds. First mortgage bonds are issued under and secured by the Mortgage and Deed of Trust, dated July 1, 1939, between WEI and The Bank of New York Mellon Trust Company, N.A., as successor to Harris Trust and Savings Bank, as trustee, as supplemented and amended by supplemental indentures. The material provisions of the mortgage are summarized below.

Issuance of Bonds

Bonds, when issued, may rank equally with the bonds of other series then outstanding, and may be issued having dates, maturities, interest rates, redemption prices and other terms as may be determined by WTI's Board of Directors. Additional bonds may be issued under the mortgage in principal amounts not exceeding the sum of:

(1) 60% (so long as any bonds issued prior to January 1, 1997 remain outstanding, and thereafter 70%) of the net bondable value of property additions not subject to an unfunded prior lien;

(2) the principal amount of bonds retired or to be retired (except out of trust monies); and

(3) the amount of cash deposited with the trustee for such purpose, which may thereafter be withdrawn upon the same basis that additional bonds are issuable under (1) or (2) above.

Additional bonds may not be issued on the basis of property additions subject to an unfunded prior lien.

In addition to the restrictions discussed above, so long as any bonds issued prior to January 1, 1997 remain outstanding, additional bonds may not be issued unless our unconsolidated net earnings available for interest, depreciation and property retirements for a period of any 12 consecutive months during the period of 15 calendar months immediately preceding the first day of the month in which the application for authentication and delivery of additional bonds is made shall have been not less than the greater of two times (two and one-half times after all bonds issued prior to January 1, 1997 are no longer outstanding) the annual interest charges on, and 10% of the principal amount of, all bonds then outstanding, all additional bonds then applied for, all outstanding prior lien bonds and all prior lien bonds, if any, then being applied for.

The net earnings test referred to in the previous paragraph need not be satisfied to issue additional bonds:

- on the basis of property additions subject to an unfunded prior lien which simultaneously will become a funded prior lien, if application for the issuance of the additional bonds is made at any time after a date two years prior to the date of the maturity of the bonds secured by the prior lien; and
- on the basis of the payment at maturity of bonds heretofore issued by us, or the redemption, conversion or purchase of bonds, after a date two years prior to the date on which those bonds mature.

WEI has reserved the right to amend the mortgage to eliminate the foregoing requirement.

Release of Property

The mortgage provides that, subject to various limitations, property may be released from the lien thereof on the basis of cash deposited with the trustee, bonds or purchase money obligations delivered to the trustee, prior lien bonds delivered to the trustee, or unfunded net property additions certified to the trustee. The mortgage also permits the withdrawal of cash against the certification to the trustee of gross property additions at 100%, or the net bondable value of property additions at 60% (so long as any bonds issued prior to January 1, 1997 remain outstanding, and thereafter 70%), or the deposit with the trustee of bonds we have acquired. The mortgage contains special provisions with respect to the release of all or substantially all of our gas and electric properties. WEI has reserved the right to amend the mortgage to change the release and substitution provisions.

Security and Ranking

The bonds when issued are secured, equally and ratably with all of the bonds now outstanding or hereafter issued under the mortgage, by the lien on substantially all of our fixed property and franchises purported to be conveyed by the mortgage including after-acquired property of the character intended to be mortgaged property, subject to the exceptions referred to below, to certain minor leases and easements, permitted liens, exceptions and reservations in the instruments by which WEI acquired title to its property and the prior lien of the trustee for compensation, expenses and liability.

Excepted from the lien of the mortgage are:

- cash and accounts receivable;
- contracts or operating agreements;
- securities not pledged under the mortgage;
- electric energy, gas, water, materials and supplies held for consumption in operation or held in advance of use for fixed capital purposes; and
- merchandise, appliances and supplies held for resale or lease to customers.

There is further expressly excepted any property of any other corporation, all the securities of which may be owned or later acquired by WEI. The lien of the mortgage does not apply to property of KGE so long as KGE remains WEI's wholly-owned subsidiary, to the stock of KGE owned by us or to the stock of any of our other subsidiaries. The mortgage permits WEI's consolidation or merger with, or the conveyance of all or substantially all of its property to, any other corporation; provided, among other things, that the successor corporation assumes the due and punctual payment of the principal and interest on the bonds of all series then outstanding under the mortgage and assumes the due and punctual performance of all the covenants and conditions of the mortgage.

Events of Default

An event of default under the mortgage includes:

- default in the payment of the principal of any bond when the same shall become due and payable, whether at maturity or otherwise;
- default continuing for 30 days in the payment of any installment of interest on any bond or in the payment or satisfaction of any sinking fund obligation;
- default in performance or observance of any other covenant, agreement or condition in the mortgage continuing for a period of 60 days after written notice to us thereof by the trustee or by the holders of not less than 15% of the aggregate principal amount of all bonds then outstanding;
- failure to discharge or stay within 30 days a final judgment against us for the payment of money in excess of $100,000;
- default in the payment of the principal of any prior lien bond when the same shall become due and payable, whether at maturity or otherwise, or default in the payment of any installment on interest on any prior lien bond beyond the applicable grace period specified in such prior lien bond; and
- certain events in bankruptcy, insolvency or reorganization.

The trustee is required, within 90 days after the occurrence thereof, to give to the holders of the bonds notice of all defaults known to the trustee unless such defaults shall have been cured before the giving of such notice; provided, however, that except in the case of default in the payment of the principal of, and premium, if any, or interest (including additional interest) on any of the bonds, or in the payment or satisfaction of any sinking or purchase fund installment, the trustee shall be protected in withholding notice if and so long as the trustee in good faith determines that the withholding of notice is in the interests of the holders of the bonds. The trustee is under no obligation to defend or initiate any action under the mortgage which would result in the incurring of non-reimbursable expenses unless one or more of the holders of any of the outstanding bonds furnishes the trustee with indemnity satisfactory to it against such expenses. In the event of a default, the trustee is not required to act unless requested to act by holders of at least 25% in aggregate principal amount of the bonds then outstanding. In addition, a majority of the holders of the bonds have the right to direct all proceedings under the mortgage provided the trustee is indemnified to its satisfaction.

If an event of default shall have happened and be continuing, the trustee may, in its discretion and, upon written request of not less than 25% of the bondholders, shall by notice in writing delivered to WEI declare the principal amount of all bonds, if not already due and payable, to be immediately due and payable; and upon any such declaration of all bonds shall become and be immediately due and payable. This provision, however, is subject to the condition that, if at any time after the principal of the bonds shall have been so declared due and payable and prior to the date of maturity thereof as stated in the bonds and before any sale of the trust estate shall have been made, all arrears of interest upon all such bonds (with interest at the rate specified in such bonds on any overdue installment of interest and the expenses of the trustee, its agents and attorneys) shall either be paid by WEI or be collected and paid out of the trust estate, and an defaults as aforesaid (other than the payment of principal which has been so declared due and payable) shall have been made good or secured to the satisfaction of the trustee or provision deemed by the trustee to be adequate shall be made therefor, then, and in every such case, a majority of the bondholders may waive such default and its consequences and rescind such declaration; but no such waiver shall extend to or affect any subsequent default or impair or exhaust any right or power consequent thereon.

Kansas Gas and Electric Company Mortgage

From time to time, Kansas Gas and Electric Company ("KGE") issues bonds under its Mortgage and Deed of Trust, dated as of April 1, 1940, to The Bank of New York Mellon Trust Company, N.A. (successor to BNY Midwest Trust Company) and Richard Tarnas (successor to Judith L. Bartolini, W.A. Spooner, Henry A. Theis, Oliver Brooks, Wesley L. Baker, Edwin F. McMichael and R. Amundsen), as trustees, as supplemented by indentures supplemental thereto. The material provisions of the mortgage are summarized below.

Issuance of Bonds

The maximum principal amount of bonds which may be issued under the mortgage is not limited, but until changed by a future supplemental indenture the amount of advances (over and above the original issue of $16,000,000 of Bonds) which may be secured by the lien created by the mortgage shall not exceed $3.5 billion.

Bonds of any series may be issued from time to time on the basis of

(1) 70% of property additions after adjustments to offset retirements, or net property additions;
(2) retirement of bonds or prior lien bonds; and
(3) deposit of cash.

Further, with certain exceptions in the case of (2) above, the issuance of bonds is subject to a "net earnings" test whereby net earnings for 12 consecutive months out of the preceding 15 months before income taxes and before provision for retirement and depreciation of property is required to be (i) at least two and one-half times the annual interest requirements on all bonds at the time outstanding, including the additional issue, and on all indebtedness of prior rank or (ii) at least 10% of the principal amount of such bonds and prior indebtedness.

Cash deposited as a basis for the issuance of bonds may be withdrawn from time to time in an amount equal to the principal amount of bonds which KGE would otherwise be entitled to issue (without, however, applying any earnings test) upon waiver of the right to issue the same or may be used for the purchase, payment or redemption of bonds.

Property additions generally include electric, gas, steam or hot water property, acquired after December 31, 1939, but may not include securities, vehicles or automobiles, or property used principally for the production, gathering or transmission of natural gas. KGE has reserved the right to amend the mortgage, without any consent or other action by the holders of bonds, to include nuclear fuel (and similar or analogous devices or substances) as property additions. The mortgage contains certain restrictions upon the issuance of bonds against property subject to liens and upon the increase of the amount of such liens.

Release of Property

Property may be released against (1) deposit of cash or, to a limited amount, purchase money mortgages, (2) property additions, and (3) waiver of the right to issue bonds, without applying any earnings test. Cash so deposited may be withdrawn upon the bases stated in (2) and (3) above. The mortgage contains special provisions with respect to prior lien bonds pledged, and disposition of moneys received on pledged prior lien bonds.

Security and Ranking

Bonds issued under the mortgage, which constitutes a first mortgage lien on all of KGE's present properties, subject to (a) leases of minor portions of KGE property to others for uses which do not interfere with our business, (b) leases of certain of our property not used in KGE's electric utility business, (c) excepted encumbrances and (d) minor defects and irregularities in titles to properties. There are excepted from the lien all cash and securities, certain equipment, materials or supplies, vehicles and automobiles and receivables, contracts, leases and operating agreements. Bonds rank equally with all other bonds outstanding under the mortgage.

The mortgage contains provisions for subjecting after-acquired property (subject to pre-existing liens) to the lien thereof, subject to limitations in the case of consolidation, merger or sale of substantially all of KGE's assets.

The mortgage provides that the trustees shall have a lien upon the mortgaged property, prior to the bonds, for the payment of their reasonable compensation and expenses and for indemnity against certain liabilities.

Events of Default

An event of default occurs upon:

- default in payment of principal;
- default for 60 days in payment of interest;
- default in payment of interest or principal of prior lien bonds continued beyond grace period;
- default for 60 days in payment of installments of funds required for the purchase or redemption of bonds;
- certain events of bankruptcy, insolvency or reorganization; and
- default for 90 days after notice in other covenants.

The trustees may withhold notice of default (except in payment of principal, interest or funds required for the purchase or redemption of bonds) if they determine it to be in the interests of the bondholders.

In case of default, the holders of 25% of the bonds may declare the principal and interest due and payable, but the holders of a majority of the bonds may annul such declaration and destroy its effect if such default has been cured. No holder of bonds may enforce the lien of the mortgage unless such holder shall have given the trustees written notice of a default or unless the holders of 25% of the bonds have requested the trustees in writing to act and have offered the trustees reasonable opportunity to act.

The trustees are not required to risk their funds or incur personal liability if there is reasonable ground for believing that repayment is not reasonably assured. Holders of a majority of the bonds may direct the time, method and place of conducting any proceedings for any remedy available to the trustees, or exercising any trust or power conferred upon the trustees.

Westar Energy, Inc. Credit Facility (2011)

On February 18, 2011, WEI entered into a new revolving credit facility. The new facility matures on February 18, 2015. So long as there is no default under the facility, WEI may elect to extend the facility for up to an additional two years, subject to lender participation. The facility allows us to borrow up to an aggregate of $270.0 million, including letters of credit up to a maximum aggregate amount of $100.0 million. So long as there is no default under the facility, WEI may elect to increase the aggregate amount of borrowings under the facility to $400.0 million by increasing the commitment of one or more lenders who have agreed to such increase. All borrowings under the facility are secured by first mortgage bonds of Kansas Gas and Electric Company. WEI may elect to release this security at any time that our senior unsecured debt is rated investment grade by at least two of S&P, Moody's and Fitch.

The February 18, 2011 Credit Agreement is attached as Exhibit 10.1 to WEI's Current Report on Form 8-K filed on February 18, 2011.

Westar Energy, Inc. Credit Facility (2008)

On February 22, 2008, WEI amended and restated its revolving credit facility dated March 17, 2006 to increase the amount of lender commitments and make certain other changes. The amended and restated revolving credit facility matures on March 17, 2012 (March 17, 2011 as to $20.0 million in lender commitments). So long as there is no default or event of default under the revolving credit facility, WEI may elect to extend the credit facility for up to an additional five years, subject to lender participation. The amended and restated facility allows us to borrow up to an aggregate of $750.0 million, including letters of credit. All borrowings under the revolving credit facility are secured by first mortgage bonds of Kansas Gas and Electric Company.

The February 22, 2008 Third Amended and Restated Credit Agreement is attached as Exhibit 10.1 to WEI's Current Report on Form 8-K filed on February 26, 2008.

Westar Energy, Inc. **Attachment B(5)**

Ringfencing Compliance Filing

May 31, 2011

Report requirements:

B. Each jurisdictional public utility shall provide annually by May 31st the following information using diagrams, schedules or narrative discussion as may be appropriate:

5. To the extent financial separations are maintained for either legal or financial accounting purposes and at a level in which financial statements are reasonably capable of being produced by the utility's accounting system, each jurisdictional public utility shall file income statements, balance sheets and cash flow statements for (1) consolidated utility operations; (2) consolidated non-regulated operations; and (3) consolidated corporate financials; and

Westar Energy Response:

Westar Energy, Inc. consolidated corporate financial statements (with notes) are attached. The FERC Form 1 for each Westar Energy, Inc. (standalone) and Kansas Gas and Electric Company have been previously provided to the Commission on or about April 15, 2011 and are incorporated herein by this reference. Pursuant to the exception stated on Page 4 of the Report regarding entities comprising less than 10% of the consolidated assets or 10% of the consolidated revenues of the parent jurisdictional public utility, financial statements regarding consolidated non-regulated operations are not attached.

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

	Year Ended December 31,		
	2010	2009	2008
REVENUES	$ 2,056,171	$ 1,858,231	$ 1,838,996
OPERATING EXPENSES:			
Fuel and purchased power	583,361	534,864	694,348
Operating and maintenance	520,409	516,930	471,838
Depreciation and amortization	271,937	251,534	203,738
Selling, general and administrative	207,607	199,961	184,427
Total Operating Expenses	1,583,314	1,503,289	1,554,351
INCOME FROM OPERATIONS	472,857	354,942	284,645
OTHER INCOME (EXPENSE):			
Investment earnings (losses)	7,026	12,658	(10,453)
Other income	5,369	7,128	29,658
Other expense	(16,655)	(17,188)	(15,324)
Total Other (Expense) Income	(4,260)	2,598	3,881
Interest expense	174,941	157,360	106,450
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	293,656	200,180	182,076
Income tax expense	85,032	58,850	3,936
INCOME FROM CONTINUING OPERATIONS	208,624	141,330	178,140
Results of discontinued operations, net of tax	—	33,745	—
NET INCOME	208,624	175,075	178,140
Less: Net income attributable to noncontrolling interests	4,728	—	—
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY	203,896	175,075	178,140
Preferred dividends	970	970	970
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 202,926	$ 174,105	$ 177,170
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY (see Note 2):			
Basic earnings available from continuing operations	$ 1.81	$ 1.28	$ 1.69
Discontinued operations, net of tax	—	0.30	—
Basic earnings per common share	$ 1.81	$ 1.58	$ 1.69
Diluted earnings available from continuing operations	$ 1.80	$ 1.28	$ 1.69
Discontinued operations, net of tax	—	0.30	—
Diluted earnings per common share	$ 1.80	$ 1.58	$ 1.69
Average equivalent common shares outstanding	111,629,292	109,647,689	103,958,414
DIVIDENDS DECLARED PER COMMON SHARE	$ 1.24	$ 1.20	$ 1.16
AMOUNTS ATTRIBUTABLE TO WESTAR ENERGY:			
Income from continuing operations	$ 203,896	$ 141,330	$ 178,140
Results of discontinued operations, net of tax	—	33,745	—
Net income	$ 203,896	$ 175,075	$ 178,140

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

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

	Year Ended December 31,		
	2010	2009	2008
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$ 208,624	$ 175,075	$ 178,140
Discontinued operations, net of tax	—	(33,745)	—
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	271,937	251,534	203,738
Amortization of nuclear fuel	25,089	16,161	14,463
Amortization of deferred regulatory gain from sale-leaseback	(5,495)	(5,495)	(5,495)
Amortization of corporate-owned life insurance	20,650	22,116	18,920
Non-cash compensation	11,373	5,133	4,696
Net changes in energy marketing assets and liabilities	(1,284)	8,972	(7,018)
Accrued liability to certain former officers	2,675	2,296	(1,449)
Gain on sale of utility plant and property	—	—	(1,053)
Net deferred income taxes and credits	120,169	46,447	35,261
Stock-based compensation excess tax benefits	(641)	(448)	(561)
Allowance for equity funds used during construction	(3,104)	(5,031)	(18,284)
Changes in working capital items:			
Accounts receivable	(11,434)	(17,159)	(3,331)
Inventories and supplies	(12,266)	10,466	(11,764)
Prepaid expenses and other	8,475	(10,635)	(52,615)
Accounts payable	30,330	(15,115)	(73,971)
Accrued taxes	27,565	30,493	27,938
Other current liabilities	(80,660)	13,572	(5,732)
Changes in other assets	(42,544)	73,784	29,389
Changes in other liabilities	38,243	(89,516)	(56,382)
Cash Flows from Operating Activities	607,702	478,905	274,890
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(540,076)	(555,637)	(918,958)
Investment in corporate-owned life insurance	(19,162)	(17,724)	(18,720)
Purchase of securities within trust funds	(192,350)	(64,016)	(210,599)
Sale of securities within trust funds	191,603	61,096	221,613
Proceeds from investment in corporate-owned life insurance	2,204	1,748	27,320
Proceeds from sale of plant and property	—	—	4,295
Proceeds from federal grant	3,180	—	—
Investment in affiliated company	(280)	(818)	—
Other investing activities	(1,164)	2,920	(11,388)
Cash Flows used in Investing Activities	(556,045)	(572,431)	(906,437)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	(16,060)	67,860	(5,100)
Proceeds from long-term debt	—	347,507	544,715
Retirements of long-term debt	(1,695)	(196,821)	(101,311)
Retirements of long-term debt of variable interest entities	(28,610)	—	—
Repayment of capital leases	(2,981)	(10,190)	(9,820)
Borrowings against cash surrender value of corporate-owned life insurance	74,134	10,299	64,255
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(3,430)	(3,531)	(28,634)
Stock-based compensation excess tax benefits	641	448	561
Issuance of common stock, net	54,651	4,587	293,621
Distributions to shareholders of noncontrolling interests	(2,093)	—	—
Cash dividends paid	(129,146)	(122,937)	(109,579)
Cash Flows (used in) from Financing Activities	(54,589)	97,222	648,708
CASH FLOWS USED IN INVESTING ACTIVITIES OF DISCONTINUED OPERATIONS:			
Payment of settlement to former subsidiary	—	(22,750)	—
Cash flows used in investing activities of discontinued operations	—	(22,750)	—
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(2,932)	(19,054)	17,161
CASH AND CASH EQUIVALENTS:			
Beginning of period	3,860	22,914	5,753
End of period	$ 928	$ 3,860	$ 22,914

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

WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Dollars in Thousands)

	Westar Energy Shareholders						
	Cumulative preferred stock	Common stock	Paid-in capital	Retained earnings	Accumulated other comprehensive income (loss)	Noncontrolling interests	Total equity
Balance at December 31, 2007	$ 21,436	$ 477,316	$ 1,085,099	$ 264,477	$ 152	$ —	$ 1,848,480
Net income	—	—	—	178,140	—	—	178,140
Issuance of common stock, net	—	64,240	239,316	—	—	—	303,556
Preferred dividends	—	—	—	(970)	—	—	(970)
Dividends on common stock	—	—	—	(123,107)	—	—	(123,107)
Reclass to temporary equity	—	—	1,802	—	—	—	1,802
Amortization of restricted stock	—	—	3,941	—	—	—	3,941
Stock compensation and tax benefit	—	—	(3,767)	—	—	—	(3,767)
Adjustment to retained earnings – Pension and other post-retirement benefit plans	—	—	—	(495)	—	—	(495)
Adjustment to retained earnings – Fair value option	—	—	—	152	(152)	—	—
Balance at December 31, 2008	21,436	541,556	1,326,391	318,197	—	—	2,207,580
Net income	—	—	—	175,075	—	—	175,075
Issuance of common stock, net	—	3,804	10,569	—	—	—	14,373
Preferred dividends	—	—	—	(970)	—	—	(970)
Dividends on common stock	—	—	—	(132,103)	—	—	(132,103)
Reclass to temporary equity	—	—	(20)	—	—	—	(20)
Amortization of restricted stock	—	—	4,524	—	—	—	4,524
Stock compensation and tax benefit	—	—	(1,674)	—	—	—	(1,674)
Balance at December 31, 2009	21,436	545,360	1,339,790	360,199	—	—	2,266,785
Net income	—	—	—	203,896	—	4,728	208,624
Issuance of common stock, net	—	15,280	50,759	—	—	—	66,039
Preferred dividends	—	—	—	(970)	—	—	(970)
Dividends on common stock	—	—	—	(139,478)	—	—	(139,478)
Reclass to temporary equity	—	—	(22)	—	—	—	(22)
Amortization of restricted stock	—	—	10,710	—	—	—	10,710
Stock compensation and tax benefit	—	—	(2,657)	—	—	—	(2,657)
Consolidation of noncontrolling interests	—	—	—	—	—	3,435	3,435
Distributions to shareholders of noncontrolling interests	—	—	—	—	—	(2,093)	(2,093)
Balance at December 31, 2010	$ 21,436	$ 560,640	$ 1,398,580	$ 423,647	$ —	$ 6,070	$ 2,410,373

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

WESTAR ENERGY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

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

We provide electric generation, transmission and distribution services to approximately 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 consolidated financial statements in accordance with GAAP for the United States of America. Our 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. Undivided interests in jointly-owned generation facilities are included on a proportionate basis. Intercompany accounts and transactions have been eliminated in consolidation.

Use of Management's Estimates

When we prepare our consolidated financial statements, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities at the date of our consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an on-going basis, including those related to bad debts, inventories, valuation of commodity contracts, depreciation, unbilled revenue, valuation of investments, valuation of our energy marketing portfolio, forecasted fuel costs included in our retail energy cost adjustment (RECA) billed to customers, income taxes, pension and other post-retirement benefits, our asset retirement obligations (AROs) including the decommissioning of Wolf Creek Generating Station (Wolf Creek), environmental issues, VIEs, contingencies and litigation. Actual results may differ from those estimates under different assumptions or conditions.

Regulatory Accounting

We apply accounting standards that recognize the economic effects of rate regulation. Accordingly, we have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent. See Note 3, "Rate Matters and Regulation," for additional information regarding our regulatory assets and liabilities.

Cash and Cash Equivalents

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

Inventories and Supplies

We state inventories and supplies at average cost.

Property, Plant and Equipment

We record the value of property, plant and equipment, and property, plant and equipment of VIEs at cost. For plant, cost includes contracted services, direct labor and materials, indirect charges for engineering and supervision and an allowance for funds used during construction (AFUDC). AFUDC represents the allowed cost of capital used to finance utility construction activity. We compute AFUDC by applying a composite rate to qualified construction work in progress. We credit to other income (for equity funds) and interest expense (for borrowed funds) the amount of AFUDC capitalized as construction cost on the accompanying consolidated statements of income as follows:

	Year Ended December 31,		
	2010	2009	2008
		(Dollars In Thousands)	
Borrowed funds	$ 4,295	$ 4,857	$ 20,536
Equity funds	3,104	5,031	18,284
Total	$ 7,399	$ 9,888	$ 38,820
Average AFUDC Rates	2.6%	4.2%	6.4%

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

Depreciation

We depreciate utility plant using a straight-line method. These rates are based on an average annual composite basis using group rates that approximated 2.9% in 2010, 3.0% in 2009 and 2.6% in 2008.

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

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

Nuclear Fuel

We record as property, plant and equipment our share of the cost of nuclear fuel used in the process of refinement, conversion, enrichment and fabrication. We reflect this at original cost and amortize such amounts to fuel expense based on the quantity of heat consumed during the generation of electricity, as measured in millions of British thermal units (MMBtu). The accumulated amortization of nuclear fuel in the reactor was $48.0 million as of December 31, 2010, and $22.9 million as of December 31, 2009. Cost of nuclear fuel charged to fuel and purchased power expense was $29.2 million in 2010, $20.1 million in 2009 and $18.3 million in 2008.

Cash Surrender Value of Life Insurance

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Cash surrender value of policies	$1,280,615	$1,209,304
Borrowings against policies	(1,144,248)	(1,073,544)
Corporate-owned life insurance, net	$ 136,367	$ 135,760

We record as income increases in cash surrender value and death benefits. We offset against policy income the interest expense that we incur on policy loans. Income from death benefits is highly variable from period to period.

Revenue Recognition

Electricity Sales

We record revenue at the time we deliver electricity to customers. We determine the amounts delivered to individual customers through systematic monthly readings of customer meters. At the end of each month, we estimate how much electricity we have delivered since the prior meter reading and record the corresponding unbilled revenue.

Our unbilled revenue estimate is affected by factors including fluctuations in energy demand, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $53.8 million as of December 31, 2010, and $56.6 million as of December 31, 2009.

Energy Marketing Contracts

We account for energy marketing derivative contracts under the fair value method of accounting. Under this method, we recognize changes in the portfolio value as gains or losses in the period of change. With the exception of certain fuel supply and electricity contracts, which we record as regulatory assets or regulatory liabilities, we include the net change in fair value in revenues on our consolidated statements of income. We record the unrealized gains and losses as energy marketing long-term or short-term assets and liabilities on our consolidated balance sheets as appropriate. We use quoted market prices to value our energy marketing derivative contracts when such data are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. The prices we use to value these transactions reflect our best estimate of the fair value of these contracts. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

Normal Purchases and Normal Sales Exception

Determining whether a contract qualifies for the normal purchases and normal sales exception requires that we exercise judgment on whether the contract will physically deliver and requires that we ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and price is not tied to an unrelated underlying derivative.

Allowance for Doubtful Accounts

We determine our allowance for doubtful accounts based on the age of our receivables. We charge receivables off when they are deemed uncollectible, which is based on a number of factors including specific facts surrounding an account and management's judgment.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under this method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over the lives of the related properties as required by tax laws and regulatory practices. We recognize production tax credits in the year that electricity is generated to the extent that realization of such benefits is more likely than not.

We record deferred tax assets to carry forward into future periods capital losses, operating losses and tax credits. However, when we believe based on available evidence that we do not, or will not, have sufficient future capital gains or taxable income in the appropriate taxing jurisdiction to realize the entire benefit during the applicable carryforward period, we record a valuation allowance against the deferred tax asset.

The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Accordingly, we must make judgments regarding income tax exposure. Interpretations of and guidance surrounding income tax laws and regulations change over time. As a result, changes in our judgments can materially affect amounts we recognize in our consolidated financial statements. See Note 10, "Taxes," for additional detail on our accounting for income taxes.

Sales Taxes

We account for the collection and remittance of sales tax on a net basis. As a result, we do not reflect them in our consolidated statements of income.

Earnings Per Share

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

Under the two-class method, we reduce net income attributable to common stock by the amount of dividends declared in the current period. We allocate the remaining earnings to common stock and RSUs to the extent that each security may share in earnings as if all of the earnings for the period had been distributed. We determine the total earnings allocated to each security by adding together the amount allocated for dividends and the amount allocated for a participation feature. To compute basic EPS, we divide the earnings allocated to common stock by the weighted average number of common shares outstanding. Diluted EPS includes the effect of potential issuances of common shares resulting from our forward sale agreements, RSUs that do not have nonforfeitable 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 income from continuing operations.

	Year Ended December 31, 2010	2009	2008
	(Dollars In Thousands, Except Per Share Amounts)		
Income from continuing operations	$ 208,624	$ 141,330	$ 178,140
Less: Income attributable to noncontrolling interests	4,728	—	—
Income from continuing operations attributable to Westar Energy	203,896	141,330	178,140
Less: Preferred dividends	970	970	970
Income from continuing operations allocated to RSUs	1,259	541	1,346
Income from continuing operations attributable to common stock	$ 201,667	$ 139,819	$ 175,824
Weighted average equivalent common shares outstanding – basic	111,629,292	109,647,689	103,958,414
Effect of dilutive securities:			
Restricted share units	140,077	—	—
Forward sale agreements	245,496	—	—
Employee stock options	59	481	728
Weighted average equivalent common shares outstanding – diluted (a)	112,014,924	109,648,170	103,959,142
Earnings from continuing operations per common share, basic	$ 1.81	$ 1.28	$ 1.69
Earnings from continuing operations per common share, diluted	$ 1.80	$ 1.28	$ 1.69

(a) We did not have any antidilutive shares for the years ended December 31, 2010 and 2009. For the year ended December 31, 2008, potentially dilutive shares not included in the denominator because they are antidilutive totaled 21,300 shares.

Supplemental Cash Flow Information

	Year Ended December 31, 2010	2009	2008
	(In Thousands)		
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$ 145,463	$ 144,964	$ 102,865
Interest on financing activities of VIEs (a)	20,191	—	—
Income taxes, net of refunds	(34,980)	(7,870)	(34,905)
NON-CASH INVESTING TRANSACTIONS:			
Property, plant and equipment additions	64,423	21,614	106,219
Property, plant and equipment additions of VIEs (a)	356,964	—	—
Jeffrey Energy Center (JEC) 8% leasehold interest (a)	(108,706)	—	—
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and compensation plans	18,777	12,168	11,263
Debt of VIEs (a)	337,951	—	—
Capital lease for JEC 8% leasehold interest (a)	(106,423)	—	—
Assets acquired through capital leases	910	2,818	4,583

(a) These transactions result from the consolidation of the VIEs discussed in Note 17, "Variable Interest Entities."

New Accounting Pronouncements

We prepare our consolidated financial statements in accordance with GAAP for the United States of America. To address current issues in accounting, the Financial Accounting Standards Board (FASB) issued the following new accounting pronouncement that affected our accounting and disclosure.

Consolidation Guidance for Variable Interest Entities

In June 2009, the FASB amended the consolidation guidance for VIEs. The amended guidance requires a qualitative assessment rather than a quantitative assessment in determining the primary beneficiary of a VIE and significantly changes the criteria to consider in determining the primary beneficiary. Pursuant to the amended guidance, there is no exclusion, or "grandfathering," of VIEs that were not consolidated under prior guidance. This amended guidance was effective for annual reporting periods beginning after November 15, 2009. We adopted the guidance effective January 1, 2010, and, as a result, began consolidating certain VIEs that hold assets we lease. See Note 17, "Variable Interest Entities," for additional information.

3. RATE MATTERS AND REGULATION

Regulatory Assets and Regulatory Liabilities

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$ 431,016	$ 369,877
Amounts due from customers for future income taxes, net	172,181	183,667
Depreciation	79,770	82,541
Debt reacquisition costs	73,099	79,342
Storm costs	34,741	56,288
Asset retirement obligations	21,546	20,719
Disallowed plant costs	16,354	16,462
Energy efficiency program costs	10,980	1,101
Wolf Creek outage	9,637	19,438
Ad valorem tax	5,680	1,195
Retail energy cost adjustment	—	13,298
Other regulatory assets	6,061	11,830
Total regulatory assets	$ 861,065	$ 855,758
Regulatory Liabilities:		
Removal costs	$ 70,342	$ 68,078
Nuclear decommissioning	25,467	16,658
Retail energy cost adjustment	16,402	27,488
La Cygne dismantling costs	13,268	—
Fuel supply and electricity contracts	7,800	6,001
Treasury yield hedges	7,711	—
Other post-retirement benefits costs	6,943	3,534
Ad valorem tax	4,934	5,604
Kansas tax credits	3,565	5,351
Other regulatory liabilities	7,606	7,994
Total regulatory liabilities	$ 164,038	$ 140,708

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

- **Deferred employee benefit costs:** Includes $407.2 million for pension and other post-retirement benefit obligations and $23.8 million for actual pension expense in excess of the amount of such expense recognized in setting our prices. During 2011, we will amortize to expense approximately $36.3 million of the benefit obligations. At the time of a future rate case, we expect to amortize the excess pension expense as part of resetting base prices. We do not earn a return on this asset.

- **Amounts due from customers for future income taxes, net:** In accordance with various orders, we have reduced our prices to reflect the income tax benefits associated with certain income tax deductions, thereby passing on these benefits to customers at the time we receive them. We believe it is probable that the net future increases in income taxes payable will be recovered from customers when these temporary income tax benefits reverse in future periods. We have recorded a regulatory asset, net of the regulatory liability, for these amounts on which we do not earn a return. We also have recorded a regulatory liability for our obligation to customers for income taxes recovered in earlier periods when corporate income tax rates were higher than current income tax rates. This benefit will be returned to customers as these temporary differences reverse in future periods. The income tax-related regulatory assets and liabilities as well as unamortized investment tax credits are also temporary differences for which deferred income taxes have been provided. These items are measured by the expected cash flows to be received or settled in future prices.

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

- **Debt reacquisition costs:** Includes costs incurred to reacquire and refinance debt. These costs are amortized over the term of the new debt. We do not earn a return on this asset.

- **Storm costs:** We accumulated and deferred for future recovery costs related to restoring our electric transmission and distribution systems from damages sustained during unusually damaging storms. We amortize these costs over periods ranging from three to five years and earn a return on a majority of this asset.

- **Asset retirement obligations:** Represents amounts associated with our AROs as discussed in Note 14, "Asset Retirement Obligations." We recover these amounts over the life of the related plant. We do not earn a return on this asset.

- **Disallowed plant costs:** In 1985, the Kansas Corporation Commission (KCC) disallowed certain costs associated with the original construction of Wolf Creek. In 1987, the KCC authorized KGE to recover these costs in prices over the useful life of Wolf Creek. We do not earn a return on this asset.

- **Energy efficiency program costs:** We accumulate and defer for future recovery costs related to our various energy efficiency programs. We will amortize such costs over a one-year period. We do not earn a return on this asset.

- **Wolf Creek outage:** Wolf Creek incurs a refueling and maintenance outage approximately every 18 months. The expenses associated with these refueling and maintenance outages are deferred and amortized over the period between such planned outages. We do not earn a return on this asset.

- **Ad valorem tax:** Represents actual costs incurred for property taxes in excess of amounts collected in our prices. We expect to recover these amounts in our prices over a one-year period. We do not earn a return on this asset.

- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. This item represents the actual cost of fuel consumed in producing electricity and the cost of purchased power in excess of the amounts we have collected from customers. We expect to recover in our prices this shortfall over a one-year period. We do not earn a return on this asset.

- **Other regulatory assets:** Includes various regulatory assets that individually are small in relation to the total regulatory asset balance. Other regulatory assets have various recovery periods, most of which range from three to five years.

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

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

- **Nuclear decommissioning:** We have a legal obligation to decommission Wolf Creek at the end of its useful life. This item represents the difference between the fair value of the assets held in a decommissioning trust and the fair value of our ARO. See Note 5, "Financial Investments and Trading Securities" and Note 14, "Asset Retirement Obligations," for information regarding our nuclear decommissioning trust (NDT) fund and our ARO.

- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. We bill customers based on our estimated costs. This item represents the amount we collected from customers that was in excess of our actual cost of fuel and purchased power. We will refund to customers this excess recovery over a one-year period.

- **La Cygne dismantling costs:** We are contractually obligated to retire a portion of the La Cygne Generating Station (La Cygne) unit 2. This item represents amounts collected but not yet spent to retire this unit and the obligation will be discharged as we dismantle the unit.

- **Fuel supply and electricity contracts:** We use fair value accounting for some of our fuel supply and electricity contracts. This represents the non-cash net gain position on fuel supply and electricity contracts that are recorded at fair value. Under the RECA, fuel supply contract market gains accrue to the benefit of our customers.

- **Treasury yield hedges:** Represents the effective portion of the gains on treasury yield hedge transactions entered into during 2010. This amount will be amortized to interest expense over the life of the related debt. See Note 4, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management – Derivative Instruments – Cash Flow Hedges," for additional information regarding our treasury yield hedge transactions.

- **Other post-retirement benefits costs:** Represents the amount of other post-retirement benefits expense recognized in setting our prices in excess of actual other post-retirement benefits expense. At the time of a future rate case, we expect to credit this excess to customers as part of resetting our base prices.

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

- **Kansas tax credits:** Represents Kansas tax credits on investments in utility plant. Amounts will be credited to customers subsequent to their realization over the remaining lives of the utility plant giving rise to the tax credits.

- **Other regulatory liabilities:** Includes various regulatory liabilities that individually are relatively small in relation to the total regulatory liability balance. Other regulatory liabilities will be credited over various periods, most of which range from one to five years.

KCC Proceedings

On October 29, 2010, the KCC issued an order, effective November 2010, allowing us to recover in our prices $5.8 million of previously deferred amounts associated with various energy efficiency programs.

On June 11, 2010, the KCC issued a final order approving an adjustment to our prices that we made earlier in 2010. The adjustment included updated transmission costs as reflected in our transmission formula rate discussed below. The new prices were effective March 16, 2010, and are expected to increase our annual retail revenues by $6.4 million.

On May 25, 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with environmental investments made in 2009. The new prices were effective June 1, 2010, and are expected to increase our annual retail revenues by $13.8 million.

On January 27, 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with investments in natural gas and wind generation facilities. The new prices were effective February 2010 and are expected to increase our annual retail revenues by $17.1 million.

On September 11, 2009, the KCC issued an order, effective January 1, 2009, allowing us to establish a regulatory asset or liability to track the cumulative difference between current year pension and post-retirement benefits expense and the amount of such expense recognized in setting our prices. At the time of a future rate case, we expect to amortize such regulatory asset or liability as part of resetting base rates.

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

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

On January 21, 2009, the KCC issued an order expected to increase our annual retail revenues by $130.0 million to reflect investments in natural gas generation facilities, wind generation facilities and other capital projects, costs to repair damage to our electrical system, which were previously deferred as a regulatory asset, higher operating costs in general and an updated capital structure. The new prices became effective on February 3, 2009.

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

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

FERC Proceedings

On October 15, 2010, we posted our updated transmission formula rate which includes projected 2011 transmission capital expenditures and operating costs. The updated rate was effective January 1, 2011, and is expected to increase our annual transmission revenues by $15.9 million.

Our transmission formula rate that includes projected 2010 transmission capital expenditures and operating costs became effective January 1, 2010, and was expected to increase our annual transmission revenues by $16.8 million. The transmission formula rate provides the basis for our annual request with the KCC to adjust our retail prices to include updated transmission costs as noted above.

On January 12, 2010, the Federal Energy Regulatory Commission (FERC) issued an order accepting our request to implement a cost-based formula rate for electricity sales to wholesale customers. The use of a cost-based formula rate allows us to annually adjust our prices to reflect changes in our cost of service. The cost-based formula rate was effective December 1, 2009.

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

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

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

During the second quarter of 2010, we changed our investment advisor for the NDT. The transition resulted in the sale of all of our then existing level 1 and level 2 investments and the purchase of other level 2 investments. Level 2 investments, whether in the 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.

We maintain certain level 3 investments in private equity, high-yield bonds 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. Level 3 debt investments are principally invested in mortgage-backed securities and collateralized loans. Fair value for these investments is determined by using subjective market- and income-based estimates such as projected cash flows and future interest rates. 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 December 31, 2010 and 2009.

	Carrying Value		Fair Value	
	As of December 31,			
	2010	2009	2010	2009
	(In Thousands)			
Fixed-rate debt (a)	$2,373,373	$2,373,723	$2,570,648	$2,528,456
Fixed-rate debt of VIEs	308,317	—	341,328	—

(a) This amount does not include an equipment financing loan of $0.1 million and $1.4 million in 2010 and 2009, respectively.

Recurring Fair Value Measurements

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

As of December 31, 2010	Level 1	Level 2	Level 3	Total
		(In Thousands)		
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 Hedge	—	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
As of December 31, 2009				
Assets:				
Energy Marketing Contracts	$ 7,310	$ 17,071	$ 19,431	$ 43,812
Nuclear Decommissioning Trust:				
Domestic equity	34,961	5,317	2,262	42,540
International equity	1,208	24,736	—	25,944
Core bonds	16,082	5,524	—	21,606
High-yield bonds	5,579	—	5,741	11,320
Real estate securities	—	—	3,635	3,635
Commodities	5,563	—	—	5,563
Cash equivalents	1,660	—	—	1,660
Total Nuclear Decommissioning Trust	65,053	35,577	11,638	112,268
Trading Securities:				
Domestic equity	—	18,344	—	18,344
International equity	—	4,422	—	4,422
Core bonds	—	11,853	—	11,853
Total Trading Securities	—	34,619	—	34,619
Total Assets Measured at Fair Value	$ 72,363	$ 87,267	$ 31,069	$ 190,699
Liabilities:				
Energy Marketing Contracts	$ 8,964	$ 15,286	$ 15,121	$ 39,371

We do not offset the fair value of energy marketing contracts executed with the same counterparty. As of December 31, 2010, we had no right to reclaim cash collateral and $0.7 million for our obligation to return cash collateral. As of December 31, 2009, we had recorded $0.3 million for our right to reclaim cash collateral and $1.8 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 years ended December 31, 2010 and 2009.

	Energy Marketing Contracts, net	Nuclear Decommissioning Trust: Domestic Equity	Nuclear Decommissioning Trust: High-yield Bonds	Nuclear Decommissioning Trust: Real Estate Securities	Net Balance
			(In Thousands)		
Balance as of December 31, 2009	$ 4,310	$ 2,262	$ 5,741	$ 3,635	$ 15,948
Total realized and unrealized gains (losses) included in:					
Earnings (a)	(2,585)	—	—	—	(2,585)
Regulatory assets	3,311 (b)	—	—	—	3,311
Regulatory liabilities	8,148 (b)	16	367	(586)	7,945
Purchases, issuances and settlements	(1,369)	589	(5,803)	—	(6,583)
Balance as of December 31, 2010	$ 11,815	$ 2,867	$ 305	$ 3,049	$ 18,036
Balance as of December 31, 2008	$ 44,541	$ 2,006	$ —	$ 6,028	$ 52,575
Total realized and unrealized gains (losses) included in:					
Earnings (a)	3,060	—	—	—	3,060
Regulatory assets	(15,382) (b)	—	—	—	(15,382)
Regulatory liabilities	(22,750) (b)	(39)	1,134	(2,393)	(24,048)
Purchases, issuances and settlements	(5,159)	295	4,607 (c)	—	(257)
Balance as of December 31, 2009	$ 4,310	$ 2,262	$ 5,741	$ 3,635	$ 15,948

(a) Unrealized and realized gains and losses included in earnings resulting from energy marketing activities are reported in revenues.

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

(c) We used proceeds from the sale of certain debt investments measured at fair value using level 2 inputs to purchase different debt investments that require significant unobservable inputs in order to measure their fair value.

A portion of the gains and losses contributing to changes in net assets in the above table is unrealized. The following table summarizes the unrealized gains and losses we recorded on our consolidated financial statements during the years ended December 31, 2010 and 2009, attributed to level 3 assets and liabilities.

	Year Ended December 31, 2010				
	Energy Marketing Contracts, net	Nuclear Decommissioning Trust: Domestic Equity	Nuclear Decommissioning Trust: High-yield Bonds	Nuclear Decommissioning Trust: Real Estate Securities	Net Balance
			(In Thousands)		
Total unrealized gains (losses) included in:					
Earnings (a)	$ (1,441)	$ —	$ —	$ —	$ (1,441)
Regulatory assets	180 (b)	—	—	—	180
Regulatory liabilities	2,633 (b)	23	(31)	(586)	2,039
Total	$ 1,372	$ 23	$ (31)	$ (586)	$ 778
	Year Ended December 31, 2009				
Total unrealized gains (losses) included in:					
Earnings (a)	$ (474)	$ —	$ —	$ —	$ (474)
Regulatory assets	(8,545) (b)	—	—	—	(8,545)
Regulatory liabilities	(9,634) (b)	(39)	1,134	(2,497)	(11,036)
Total	$ (18,653)	$ (39)	$ 1,134	$ (2,497)	$ (20,055)

(a) Unrealized gains and losses included in earnings resulting from energy marketing activities 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 further information on these investments.

	As of December 31, 2010		As of December 31, 2009		As of December 31, 2010	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
	(In thousands)					
Nuclear Decommissioning Trust:						
Domestic equity	$ 2,867	$ 2,523	$ 7,579	$ 3,111	(a)	(a)
High-yield bonds	305	—	5,741	—	(b)	(b)
Real estate securities	3,049	—	3,635	—	(c)	(c)
Total	$ 6,221	$ 2,523	$ 16,955	$ 3,111		
Trading Securities:						
Domestic equity	$ 21,207	$ —	$ 18,344	$ —	Upon Notice	1 day
International equity	5,128	—	4,422	—	Upon Notice	1 day
Core bonds	13,077	—	11,853	—	Upon Notice	1 day
Total Trading Securities	39,412	—	34,619	—		
Total	$ 45,633	$ 2,523	$ 51,574	$ 3,111		

(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 to make distributions and we expect the other to begin in 2013.

(b) We expect to completely settle this fund in the second 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 any liquidity associated with this investment.

Nonrecurring Fair Value Measurements

We have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operations of such assets. In 2010 we did not incur any additional AROs. In 2009 we incurred $21.6 million of additional AROs, including $20.3 million increase in our ARO to reflect revisions to the estimated cost to decommission Wolf Creek. We initially record AROs at fair value for the estimated cost to satisfy the retirement obligation. The fair value is measured by estimating the cost to satisfy the retirement obligation then discounting that value at a risk- and inflation-adjusted rate. To determine the cost to satisfy the retirement obligation, we must estimate the cost of basic inputs such as labor, energy, materials and disposal. To determine the appropriate discount rate, we use inputs such as inflation rates, short and long-term yields for U.S. government securities and our nonperformance risk. Due to the significant unobservable inputs required in our measurement, we have determined that our fair value measurements of our AROs are level 3 in the fair value hierarchy. For additional information on our AROs, see Note 14, "Asset Retirement Obligations."

Derivative Instruments

Cash Flow Hedges

In 2010, we entered into treasury yield hedge transactions for a total notional amount of $100.0 million in order to manage our interest rate risk associated with a future anticipated issuance of fixed-rate debt, which must occur within 18 months of the initial treasury yield hedge transaction date. 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 gain or loss 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 December 31, 2010, the fair value of the treasury yield hedge transactions was $7.7 million, which we recorded in other assets on our consolidated balance sheet. We also recorded this same amount in long-term regulatory liabilities on our consolidated balance sheet to reflect the effective portion of the gains on these transactions for the year ended December 31, 2010.

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, including futures contracts, options and 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 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

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

Asset Derivatives		**Liability Derivatives**	
Balance Sheet Location	Fair Value (In thousands)	Balance Sheet Location	Fair Value (In thousands)
Current assets:		Current liabilities:	
Energy marketing contracts	$ 33,159	Energy marketing contracts ..	$ 39,161
Other assets:		Long-term liabilities:	
Energy marketing contracts	10,653	Energy marketing contracts ..	210
Total	$ 43,812	Total	$ 39,371

The following table presents how changes in the fair value of commodity derivative instruments affected our consolidated financial statements for the years ended December 31, 2010 and 2009.

Location	Year Ended December 31, 2010	Year Ended December 31, 2009	
	Net Gain Recognized	Net Gain Recognized	Net Loss Recognized
	(In Thousands)		
Revenues increase	$ 712	$ 7,790	$ —
Regulatory assets (decrease) increase	(7,604)	—	7,064
Regulatory liabilities increase (decrease)	1,799	—	(30,330)

As of December 31, 2010 and 2009, we had under contract the following energy-related products.

	Unit of Measure	Net Quantity as of December 31, 2010	Net Quantity as of December 31, 2009
Electricity	MWh	2,791,966	4,147,800
Natural Gas	MMBtu	1,150,000	648,000
Coal	Ton	—	3,500,000

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

Energy Marketing Activities

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

Price Risk

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

Factors that affect our commodity price exposure are the quantity and availability of fuel used for generation, the availability of our generating plants and the quantity of electricity customers consume. Quantities of fossil fuel we use to generate electricity fluctuate from period to period based on availability, price and deliverability of a given fuel type, as well as planned and unscheduled outages at our generating plants that use fossil fuels. Our commodity exposure is also affected by our nuclear plant refueling and maintenance schedule. Our customers' electricity usage also varies based on weather, the economy and numerous other factors.

The wholesale power and fuel markets are volatile. This volatility impacts our costs of purchased power, fuel costs for our generating plants and our participation in energy markets. We trade various types of fuel primarily to reduce exposure related to the volatility of commodity prices. A significant portion of our coal requirements is purchased under long-term contracts to hedge much of the fuel exposure for customers. If we were unable to generate an adequate supply of electricity for our customers, we would purchase power in the wholesale market to the extent it is available, subject to possible transmission constraints, and/or implement curtailment or interruption procedures as permitted in our tariffs and terms and conditions of service.

Interest Rate Risk

We have entered into numerous fixed and variable rate debt obligations. For details, see Note 9, "Long-Term Debt." We manage our interest rate risk related to these debt obligations by limiting our variable interest rate exposure, utilizing various 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 constraint and other risks. Declines in the creditworthiness of our counterparties could have a material adverse impact on our overall exposure to credit risk. We maintain credit policies with regard to our counterparties intended to reduce our overall credit risk exposure to a level we deem acceptable and include the right to offset derivative assets and liabilities by counterparty.

We have derivative instruments with commodity exchanges and other counterparties that do not contain objective credit-risk-related contingent features. However, certain of our derivative instruments contain collateral provisions subject to credit agency ratings of our senior unsecured debt. If our senior unsecured debt ratings were to decrease or fall below investment grade, the counterparties to the derivative instruments, pursuant to the provisions, could require collateralization on derivative instruments. The aggregate fair value of all derivative instruments with objective credit-risk-related contingent features that were in a liability position as of December 31, 2010 and 2009, was $1.6 million and $1.4 million, respectively, for which we had posted no collateral. If all credit-risk-related contingent features underlying these agreements had been triggered as of December 31, 2010 and 2009, we would have been required to provide to our counterparties $1.6 million and $0.1 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

5. FINANCIAL INVESTMENTS AND TRADING SECURITIES

We report some of our investments in debt and equity securities at fair value. We classify these investments as either trading securities or available-for-sale securities as described below.

Trading Securities

We have 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. For the years ended December 31, 2010 and 2009, we recorded unrealized gains on these securities of $4.3 million and $11.3 million, respectively. We recorded an unrealized loss on these securities of $9.5 million for the year ended December 31, 2008.

Available-for-Sale Securities

We hold investments in equity and debt securities in a trust fund for the purpose of funding the decommissioning of Wolf Creek. We have classified these investments as available-for-sale and have recorded all such investments at their fair market value as of December 31, 2010 and 2009. At December 31, 2010, investments in the NDT fund were allocated 50% to domestic equity, 15% to international equity, 25% to core bonds, 8% to high-yield bonds, 2% to real estate securities and less than 1% to cash and cash equivalents. The core bond fund is limited to ensure 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 December 31, 2010, the fair value of the debt securities in the NDT fund was $41.5 million, held entirely in bond funds.

Using the specific identification method to determine cost, we realized a $13.2 million gain in 2010 and losses of $7.8 million and $20.1 million in 2009 and 2008, respectively, on our available-for-sale securities. We record net realized and unrealized gains and losses in regulatory liabilities on our consolidated balance sheets. This reporting is consistent with the method we use to account for the decommissioning costs we recover in our prices. Gains or losses on assets in the trust fund are recorded as increases or decreases to regulatory liabilities and could result in lower or higher funding requirements for decommissioning costs, which we believe would be reflected in the prices paid by our customers.

The following table presents the costs and fair values of investments in the NDT fund as of December 31, 2010 and 2009.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In Thousands)		
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
2009:				
Domestic equity	$ 37,648	$ 7,180	$ (2,288)	$ 42,540
International equity	22,014	4,835	(905)	25,944
Core bonds	20,260	1,346	—	21,606
High-yield bonds	11,749	31	(460)	11,320
Real estate securities	6,206	—	(2,571)	3,635
Commodities	5,895	—	(332)	5,563
Cash equivalents	1,660	—	—	1,660
Total	$105,432	$ 13,392	$ (6,556)	$ 112,268

The following table presents the fair value and the 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 December 31, 2010 and 2009.

	Less than 12 Months		12 Months or Greater		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
			(In Thousands)			
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)
2009:						
Domestic equity	$ 4,123	$ (361)	$ 10,061	$ (1,927)	$ 14,184	$ (2,288)
International equity	198	(20)	6,253	(885)	6,451	(905)
High-yield bonds	—	—	5,579	(460)	5,579	(460)
Real estate securities	40	(16)	3,595	(2,555)	3,635	(2,571)
Commodities	—	—	5,563	(332)	5,563	(332)
Total	$ 4,361	$ (397)	$ 31,051	$ (6,159)	$ 35,412	$ (6,556)

6. PROPERTY, PLANT AND EQUIPMENT

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Electric plant in service	$ 8,254,884	$ 8,057,793
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,563,566)	(3,370,805)
	5,493,636	5,489,306
Construction work in progress	392,701	214,705
Nuclear fuel, net	78,102	67,729
Net property, plant and equipment	$ 5,964,439	$ 5,771,740

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Electric plant of VIEs	$ 543,593	$ —
Accumulated depreciation of VIEs	(198,556)	—
Net property, plant and equipment of VIEs	$ 345,037	$ —

We recorded depreciation expense on property, plant and equipment of $249.2 million in 2010, $228.6 million in 2009 and $180.8 million in 2008. Approximately $9.7 million of depreciation expense in 2010 was attributable to property, plant and equipment of VIEs.

7. JOINT OWNERSHIP OF UTILITY PLANTS

Under joint ownership agreements with other utilities, we have undivided ownership interests in four electric generating stations. Energy generated and operating expenses are divided on the same basis as ownership with each owner reflecting its respective costs in its statements of income and each owner responsible for its own financing. Information relative to our ownership interest in these facilities as of December 31, 2010, is shown in the table below.

	Our Ownership as of December 31, 2010					
	In-Service Dates	Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percentage
			(Dollars in Thousands)			
La Cygne unit 1 (a)	June 1973	$ 284,101	$ (145,356)	$ 48,072	368	50
JEC unit 1 (a)	July 1978	482,582	(195,849)	8,939	666	92
JEC unit 2 (a)	May 1980	443,128	(187,356)	48,513	667	92
JEC unit 3 (a)	May 1983	673,567	(251,673)	883	659	92
Wolf Creek (b)	Sept. 1985	1,469,700	(733,036)	71,299	544	47
State Line (c)	June 2001	111,979	(41,423)	129	201	40
Total		$ 3,465,057	$ (1,554,693)	$ 177,835	3,105	

(a) Jointly owned with Kansas City Power & Light Company (KCPL). Amounts include the consolidated VIE containing an 8% leasehold interest in JEC.

(b) Jointly owned with KCPL and Kansas Electric Power Cooperative, Inc.

(c) Jointly owned with Empire District Electric Company.

We include in operating expenses on our consolidated statements of income our share of operating expenses of the above plants. Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

In addition, we also consolidate a VIE that holds our 50% leasehold interest in La Cygne unit 2, which represents 341 megawatts (MW) of net capacity. The VIE's initial investment in the 50% interest was $392.1 million and accumulated depreciation was $166.0 million as of December 31, 2010. We include these amounts in property, plant and equipment of variable interest entities, net on our consolidated balance sheets. See Note 17, "Variable Interest Entities," for additional information about VIEs.

8. SHORT-TERM DEBT

Westar Energy has a $730.0 million revolving credit facility with a syndicate of banks that terminates on March 17, 2012. On January 27, 2010, FERC approved our request for authority to issue short-term securities in an aggregate amount up to $1.0 billion including, without limitation, by increasing the size of Westar Energy's revolving credit facility. As of December 31, 2010, we had not yet exercised the increase in our authority. In addition, 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 the revolving credit facility.

The weighted average interest rate on our borrowings under the revolving credit facility was 0.61% and 0.58% as of December 31, 2010, and December 31, 2009, respectively.

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

	As of December 31,	
	2010	2009
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$213,041	$200,547
Weighted daily average interest rates during the year, excluding fees	0.63%	0.76%

Our interest expense on short-term debt was $1.9 million in 2010, $2.2 million in 2009 and $9.7 million in 2008.

9. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

	As of December 31,	
	2010	2009
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
6.00% due 2014	$ 250,000	$ 250,000
5.15% due 2017	125,000	125,000
5.95% due 2035	125,000	125,000
5.10% due 2020	250,000	250,000
5.875% due 2036	150,000	150,000
6.10% due 2047	150,000	150,000
8.625% due 2018	300,000	300,000
	1,350,000	1,350,000
Pollution control bond series:		
Variable due 2032, 0.60% as of December 31, 2010; 0.48% as of December 31, 2009	45,000	45,000
Variable due 2032, 0.54% as of December 31, 2010; 0.54% as of December 31, 2009	30,500	30,500
5.00% due 2033	57,530	57,760
	133,030	133,260
Other long-term debt:		
4.36% equipment financing loan due 2011	61	1,406
KGE		
First mortgage bond series:		
6.53% due 2037	175,000	175,000
6.15% due 2023	50,000	50,000
6.64% due 2038	100,000	100,000
6.70% due 2019	300,000	300,000
	625,000	625,000
Pollution control bond series:		
5.10% due 2023	13,343	13,463
Variable due 2027, 0.54% as of December 31, 2010; 0.64% as of December 31, 2009	21,940	21,940
5.30% due 2031	108,600	108,600
5.30% due 2031	18,900	18,900
Variable due 2032, 0.54% as of December 31, 2010; 0.64% as of December 31, 2009	14,500	14,500
Variable due 2032, 0.54% as of December 31, 2010; 0.64% as of December 31, 2009	10,000	10,000
4.85% due 2031	50,000	50,000
5.60% due 2031	50,000	50,000
6.00% due 2031	50,000	50,000
5.00% due 2031	50,000	50,000
	387,283	387,403
Total long-term debt	2,495,374	2,497,069
Unamortized debt discount (a)	(4,442)	(4,990)
Long-term debt due within one year	(61)	(1,345)
Long-term debt, net	$ 2,490,871	$2,490,734
Variable Interest Entities		
7.77% due 2013 (b)	$ 5,095	$ —
6.99% due 2014 (b)	3,237	—
5.92 % due 2019 (b)	31,171	—
5.647% due 2021 (b)	266,393	—
Total long-term debt of variable interest entities	305,896	—
Unamortized debt premium (a)	2,421	—
Long-term debt of variable interest entities due within one year	(30,155)	—
Long-term debt of variable interest entities, net	$ 278,162	$ —

(a) We amortize debt discounts and premiums to interest expense over the term of the respective issues.
(b) Portions of our payments related to this debt reduce the principal balances each year until maturity.

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

The amount of Westar Energy first mortgage bonds authorized by its Mortgage and Deed of Trust, dated July 1, 1939, as supplemented, is subject to certain limitations as described below. The amount of KGE first mortgage bonds authorized by the KGE Mortgage and Deed of Trust, dated April 1, 1940, as supplemented and amended in June 2009, is limited to a maximum of $3.5 billion, unless amended further. First mortgage bonds are secured by utility assets. Amounts of additional bonds that may be issued are subject to property, earnings and certain restrictive provisions, except in connection with certain refundings, of each mortgage. As of December 31, 2010, based on an assumed interest rate of 5.90%, approximately $817.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage, except in connection with certain refundings. As of December 31, 2010, approximately $635.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

As of December 31, 2010, we had $121.9 million of variable rate, tax-exempt bonds. Interest rates payable under these bonds are normally set by auctions, which occur every 35 days. However, auctions for these bonds have failed over the past few years, resulting in volatile alternative index-based interest rates for these bonds. With the KCC's approval, on October 15, 2009, KGE refinanced $50.0 million of auction rate bonds at a fixed interest rate of 5.00% and a maturity date of June 1, 2031. We continue to monitor the credit markets and evaluate our options with respect to our remaining auction rate bonds.

On August 3, 2009, Westar Energy repaid $145.1 million principal amount of 7.125% unsecured senior notes with borrowings under Westar Energy's revolving credit facility.

On June 11, 2009, KGE issued $300.0 million principal amount of first mortgage bonds at a discount yielding 6.725%, bearing stated interest at 6.70% and maturing on June 15, 2019. KGE received net proceeds of $297.5 million.

Proceeds from the issuance of first mortgage bonds were used to repay borrowings under Westar Energy's revolving credit facility, with such borrowed amounts principally related to investments in capital equipment, as well as for working capital and general corporate purposes.

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain leverage ratios as defined in the agreements. We calculate these ratios in accordance with our credit agreements. We use these ratios solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2010.

Maturities

The principal amounts of our long-term debt maturities as of December 31, 2010, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2011	$ 61	$ 30,155
2012	—	28,118
2013	—	25,941
2014	250,000	27,479
Thereafter	2,245,313	194,203
Total maturities	$ 2,495,374	$ 305,896

Interest expense on long-term debt was $144.1 million in 2010, $139.6 million in 2009 and $95.7 million in 2008. Interest expense on long-term debt of VIEs was $18.7 million in 2010.

10. TAXES

Income tax expense is composed of the following components.

	Year Ended December 31,		
	2010	2009	2008
		(In Thousands)	
Income Tax Expense (Benefit) from Continuing Operations:			
Current income taxes:			
Federal	$ (32,107)	$ 2,428	$ (16,484)
State	(3,030)	9,975	(14,841)
Deferred income taxes:			
Federal	102,568	46,148	35,818
State	20,305	3,003	2,147
Investment tax credit amortization	(2,704)	(2,704)	(2,704)
Income tax expense from continuing operations	$ 85,032	$ 58,850	$ 3,936
Income Tax Expense (Benefit) from Discontinued Operations:			
Current income taxes:			
Federal	$ —	$ (25,528)	$ —
State	—	(10,418)	—
Deferred income taxes:			
Federal	—	(20,549)	—
Income tax expense from discontinued operations	$ —	$ (56,495)	$ —
Total income tax expense	$ 85,032	$ 2,355	$ 3,936

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Current deferred tax assets	$ 30,248	$ 7,927
Non-current deferred tax liabilities	1,102,625	964,461
Net deferred tax liabilities	$1,072,377	$ 956,534

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Deferred tax assets:		
Deferred employee benefit costs	$ 155,400	$ 132,770
Business tax credit carryforwards (a)	134,629	101,347
Deferred gain on sale-leaseback	45,381	47,800
Deferred compensation	40,401	38,198
Accrued liabilities	35,714	35,230
Alternative minimum tax carryforward (b)	34,270	18,406
Deferred state income taxes	14,215	26,093
Disallowed costs	13,357	14,000
Long-term energy contracts	3,720	5,874
Capital loss carryforward (c)	3,527	6,075
Other	29,857	15,161
Total gross deferred tax assets	510,471	440,954
Less: Valuation allowance (c)	59,415	9,710
Deferred tax assets	$ 451,056	$ 431,244
Deferred tax liabilities:		
Accelerated depreciation	$ 931,898	$ 789,850
Acquisition premium	195,947	203,959
Deferred employee benefit costs	161,035	141,974
Amounts due from customers for future income taxes, net	152,877	165,975
Debt reacquisition costs	23,864	26,046
Deferred state income taxes	16,577	24,882
Storm costs	13,733	22,160
Other	27,502	12,932
Total deferred tax liabilities	$1,523,433	$1,387,778
Net deferred tax liabilities	$1,072,377	$ 956,534

(a) As of December 31, 2010, we had available federal general business tax credits of $18.4 million and state investment tax credits of $116.2 million. The federal general business tax credits were primarily generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These tax credits expire beginning in 2019 and ending in 2025. We believe these tax credits will be fully utilized prior to expiration. The state investment tax credits expire beginning in 2013 and ending in 2019. As we do not expect to realize sufficient state taxable income in the future, a valuation allowance of $51.9 million has been established against the unused credits which have been deferred pursuant to regulatory treatment.

(b) As of December 31, 2010, we had available alternative minimum tax credit carryforwards of $34.3 million. These tax credits have an unlimited carryforward period.

(c) As of December 31, 2010, we had a net capital loss of $8.9 million that is available to offset future capital gains. The net capital loss will expire in 2014. As we do not expect to realize any significant capital gains in the future, a valuation allowance of $3.5 million has been established. In addition, a valuation allowance of $4.0 million has been established for certain deferred tax assets related to the write-down of other investments. We also established a valuation allowance of $51.9 million as described in (a) above. The total valuation allowance related to the deferred tax assets was $59.4 million as of December 31, 2010, and $9.7 million as of December 31, 2009.

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

Our effective income tax rates are computed by dividing total federal and state income taxes by the sum of such taxes and net income. The difference between the effective income tax rates and the federal statutory income tax rates are as follows.

	For the Year Ended December 31,		
	2010	2009	2008
Statutory federal income tax rate from continuing operations	35.0%	35.0%	35.0%
Effect of:			
Corporate-owned life insurance policies	(6.1)	(8.2)	(9.1)
State income taxes	3.8	4.3	(4.5)
Production tax credits	(3.4)	(3.0)	—
Accelerated depreciation flow through and amortization	2.6	3.7	2.3
Amortization of federal investment tax credits	(0.9)	(1.4)	(1.5)
Capital loss utilization	(0.7)	(0.4)	—
AFUDC equity	(0.4)	(0.9)	(3.5)
Liability for unrecognized income tax benefits	(0.2)	0.2	(15.4)
Other	(0.7)	0.1	(1.1)
Effective income tax rate from continuing operations	29.0%	29.4%	2.2%

We file income tax returns in the U.S. federal jurisdiction, and various state and foreign jurisdictions. The income tax returns we file will likely be audited by the Internal Revenue Service (IRS) or other tax authorities. With few exceptions, the statute of limitations with respect to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities remains open for tax year 2007 and forward with tax year 2009 currently under examination by the IRS.

In November 2010, the IRS commenced an examination of our federal income tax return for tax year 2009. Also in 2010, the IRS commenced and substantially concluded its examination of the federal income tax return we filed for tax year 2008 without significant changes.

In November 2009, the IRS completed its examination of the federal income tax return and the amended federal income tax returns we filed for tax years 1999, 2005, 2006 and 2007. The examination resulted in a tax refund of $34.9 million. The examination results were approved by the Joint Committee on Taxation of the U.S. Congress and accepted by the IRS in April 2010.

In January 2009, we reached a settlement with the IRS for tax years 2003 and 2004 that included a determination of the amount of the net capital loss and net operating loss carryforwards available from the sale of a former subsidiary in 2004. This settlement resulted in our recording in 2009 a net earnings benefit from discontinued operations of approximately $33.7 million, net of $22.8 million paid to the former subsidiary under the sale agreement.

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

The amount of unrecognized income tax benefits decreased from $8.4 million at December 31, 2009, to $1.9 million at December 31, 2010. The net decrease in unrecognized income tax benefits for which a liability was not recorded was largely attributable to the reversal of $8.2 million of tax positions due to the completion of the IRS audits and the expiration of the statute of limitation. We do not expect significant changes in the liability for unrecognized income tax benefits in the next 12 months. A reconciliation of the beginning and ending amount of unrecognized income tax benefits is as follows:

	2010	2009	2008
		(In Thousands)	
Liability for unrecognized income tax benefits at January 1	$ 8,357	$ 38,980	$ 70,833
Additions based on tax positions related to the current year	608	2,254	4,576
Additions for tax positions of prior years	2,323	—	—
Reductions for tax positions of prior years	(1,241)	(25,722)	(3,639)
Settlements	(8,159)	(7,155)	(32,790)
Liability for unrecognized income tax benefits at December 31	1,888	8,357	38,980
Unrecognized income tax benefits related to amended returns filed in 2007	—	—	53,092
Unrecognized income tax benefits at December 31	$ 1,888	$ 8,357	$ 92,072

The amounts of unrecognized income tax benefits that, if recognized, would favorably impact our effective income tax rate, were $1.3 million, $2.1 million and $54.8 million (net of tax) as of December 31, 2010, 2009 and 2008, respectively. Included in the liability for unrecognized income tax benefits balances was $1.3 million, $2.1 million and $1.7 million (net of tax) of tax positions, which if recognized, would favorably impact our effective income tax rates as of December 31, 2010, 2009 and 2008, respectively.

Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. During 2010, 2009 and 2008, we reversed interest expense previously recorded for income tax uncertainties of $1.0 million, $2.4 million and $15.9 million, respectively. As of December 31, 2010 and 2009, we had $0.4 million and $1.4 million, respectively, accrued for interest on our liability related to unrecognized income tax benefits. We accrued no tax related penalties at either December 31, 2010, or December 31, 2009.

As of December 31, 2010 and 2009, we had recorded $3.6 million for probable assessments of taxes other than income taxes.

11. EMPLOYEE BENEFIT PLANS

Pension and Other Post-Retirement Benefit Plans

We maintain a qualified non-contributory defined benefit pension plan covering substantially all of our employees. For the majority of our employees, pension benefits are based on years of service and an employee's compensation during the 60 highest paid consecutive months out of 120 before retirement. Non-union employees hired after December 31, 2001, are covered by the same defined benefit pension plan; however, their benefits are derived from a cash balance account formula. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain current and retired executive officers. With the exception of one current executive officer, we have discontinued accruing any future benefits under this non-qualified plan.

In accordance with a 2009 KCC order, we expect to fund our pension plan each year at least to a level equal to our current year pension expense. We must also meet minimum funding requirements under the Employee Retirement Income Security Act (ERISA), as amended by the Pension Protection Act. We may contribute additional amounts from time to time as deemed appropriate.

In addition to providing pension benefits, we provide certain post-retirement health care and life insurance benefits for substantially all retired employees. We accrue and recover in our prices the costs of post-retirement benefits during an employee's years of service. We fund the portion of net periodic costs for other post-retirement benefits included in our prices.

As a co-owner of Wolf Creek, KGE is indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and other post-retirement benefit plans. See Note 12, "Wolf Creek Employee Benefit Plans," for information about Wolf Creek's benefit plans.

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

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2010	2009	2010	2009
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 662,495	$ 629,238	$ 128,998	$ 133,881
Service cost	13,926	12,882	1,526	1,529
Interest cost	39,391	38,162	7,083	6,917
Plan participants' contributions	—	—	3,292	3,098
Benefits paid	(29,690)	(28,526)	(11,090)	(9,960)
Actuarial losses (gains)	60,662	10,692	7,950	(13,063)
Amendments	676	47	—	6,596
Benefit obligation, end of year	$ 747,460	$ 662,495	$ 137,759	$ 128,998
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 404,243	$ 310,531	$ 74,114	$ 52,804
Actual return on plan assets	33,359	83,128	9,849	17,898
Employer contributions	22,400	37,304	10,512	9,951
Plan participants' contributions	—	—	3,147	2,953
Part D Reimbursements	—	—	317	589
Benefits paid	(27,769)	(26,720)	(10,955)	(10,081)
Fair value of plan assets, end of year	$ 432,233	$ 404,243	$ 86,984	$ 74,114
Funded status, end of year	$ (315,227)	$ (258,252)	$ (50,775)	$ (54,884)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (2,030)	$ (1,984)	$ (91)	$ (121)
Noncurrent liability	(313,197)	(256,268)	(50,684)	(54,763)
Net amount recognized	$ (315,227)	$ (258,252)	$ (50,775)	$ (54,884)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 323,924	$ 275,417	$ 8,458	$ 5,481
Prior service cost	5,819	7,872	17,065	19,219
Transition obligation	—	—	8,148	12,060
Net amount recognized	$ 329,743	$ 283,289	$ 33,671	$ 36,760

As of December 31,	Pension Benefits		Post-retirement Benefits	
	2010	2009	2010	2009
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 747,460	$ 662,495	$ —	$ —
Fair value of plan assets	432,233	404,243	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 635,541	$ 559,021	—	—
Fair value of plan assets	432,233	404,243	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 137,759	$ 128,998
Fair value of plan assets	—	—	86,984	74,114
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.35%	5.95%	5.00%	5.65%
Compensation rate increase	4.00%	4.00%	—	—

We use a measurement date of December 31 for our pension and other post-retirement benefit plans. In addition, we use an interest rate yield curve that is constructed based on the yields of over 500 high-quality, non-callable corporate bonds with maturities between zero and 30 years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of our pension plan and develop a single-point discount rate matching the plan's payout structure.

We amortize prior service cost (benefit) on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. We amortize the net actuarial loss on a straight-line basis over the average future service of active plan participants benefiting under the plan without application of an amortization corridor.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2010	2009	2008	2010	2009	2008
			(Dollars in Thousands)			
Components of Net Periodic Cost (Benefit):						
Service cost	$ 13,926	$ 12,882	$ 10,102	$ 1,526	$ 1,529	$ 1,446
Interest cost	39,391	38,162	35,792	7,083	6,917	7,637
Expected return on plan assets	(38,384)	(37,826)	(40,332)	(5,197)	(4,756)	(4,694)
Amortization of unrecognized:						
Transition obligation, net	—	—	—	3,912	3,912	3,930
Prior service costs	2,729	2,668	2,550	2,154	1,580	1,412
Actuarial loss/(gain), net	17,183	14,263	8,415	321	(38)	904
Net periodic cost before regulatory adjustment	34,845	30,149	16,527	9,799	9,144	10,635
Regulatory adjustment	(12,167)	(9,188)	—	1,868	2,280	—
Net periodic cost	$ 22,678	$ 20,961	$ 16,527	$ 11,667	$ 11,424	$ 10,635
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$ 65,690	$ (34,610)	$ 218,444	$ 3,298	$ (26,205)	$ 12,915
Amortization of actuarial (loss)/gain	(17,183)	(14,263)	(8,415)	(321)	38	(904)
Current year prior service cost	676	48	1,461	—	6,672	2,681
Amortization of prior service costs	(2,729)	(2,668)	(2,550)	(2,154)	(1,580)	(1,412)
Current year offset of Initial Transition Asset due to plan change	—	—	—	—	(76)	—
Amortization of transition obligation	—	—	—	(3,912)	(3,912)	(3,930)
Total recognized in regulatory assets	$ 46,454	$ (51,493)	$ 208,940	$ (3,089)	$ (25,063)	$ 9,350
Total recognized in net periodic cost and regulatory assets	$ 69,132	$ (30,532)	$ 225,467	$ 8,578	$ (13,639)	$ 19,985
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):						
Discount rate	5.95%	6.10%	6.25%	5.65%	6.05%	6.10%
Expected long-term return on plan assets	8.25%	8.25%	8.50%	7.75%	7.75%	7.75%
Compensation rate increase	4.00%	4.00%	4.00%	—	—	—

The estimated amounts that will be amortized from regulatory assets into net periodic cost in 2011 are as follows:

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 23,967	$ 1,016
Prior service cost	1,213	2,156
Transition obligation	—	3,912
Total	$ 25,180	$ 7,084

We base the expected long-term rate of return on plan assets on historical and projected rates of return for current and planned asset classes in the plans' investment portfolios. We select assumed projected rates of return for each asset class after analyzing long-term historical experience and future expectations of the volatility of the various asset classes. Based on target asset allocations for each asset class, we develop an overall expected rate of return for the portfolios, adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

The Medicare Prescription Drug Improvement and Modernization Act of 2003 (Medicare Act) introduced a prescription drug benefit under Medicare as well as a federal subsidy that will be paid to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare. We believe our retiree health care benefit plan is at least actuarially equivalent to Medicare and is, thus, eligible for the federal subsidy. However, due to plan changes effective January 1, 2010, we are no longer entitled to the federal subsidy. As a result, the subsidy did not have an effect on our accumulated post-retirement benefit obligation in 2010 or 2009 and did not impact our net period post-retirement benefit cost in 2010. For 2008, treating the future subsidy under the Medicare Act as an actuarial experience gain, as required by the guidance, decreased the accumulated post-retirement benefit obligation by approximately $4.0 million. The subsidy also decreased net periodic post-retirement benefit cost by approximately $1.9 million in 2009 and $0.5 million in 2008.

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

	As of December 31,	
	2010	2009
Health care cost trend rate assumed for next year	8.0%	8.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2018	2018

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

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(In Thousands)	
Effect on total of service and interest cost	$ 33	$ (30)
Effect on post-retirement benefit obligation	455	(490)

Plan Assets

We manage pension and other post-retirement benefit plan assets in accordance with the prudent investor guidelines contained in the ERISA. The plans' investment strategies support the objectives of the funds, which are to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. We delegate the management of our funds to an independent investment advisor who hires and dismisses investment managers in various asset classes based upon performance. The investment advisor strives to diversify investments across classes, sectors and manager style to minimize the risk of large losses, based upon objectives and risk tolerance specified by management, which include allowable and/or prohibited investment types. Prohibited investments include loans to the company or its officers and directors as well as investments in the company's debt or equity securities, except as may occur indirectly through investments in diversified mutual funds. In addition, we have established restrictions to reduce concentration of risk. For example, for domestic investments, no more than 5% of pension plan assets and 5% of post-retirement benefit plan assets should be invested in the securities of a single issuer, with the exception of the U.S. government and its agencies. In addition, the fund will neither acquire more than 10% of any one issuer nor acquire more than 25% of any single industry. These restrictions do not apply to the purchase of United States Government securities. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

The target allocations for our pension plan assets are about 35% to equity securities, 54% to debt securities and the remaining 11% to other investments such as real estate securities, hedge funds and private equity investments. Our investments in equity securities include investment funds with underlying investments in domestic and foreign large-, mid- and small-cap companies, derivatives related to such holdings and private equity investments. Our investments in debt securities include core and high-yield bonds. Core bonds are comprised of investment funds with underlying investments in investment grade debt securities of corporate entities, obligations of U.S. and foreign governments and their agencies and other debt securities. High-yield bonds include investment funds with underlying investments in non-investment grade debt securities of corporate entities, obligations of foreign governments and their agencies, private debt securities and other debt securities. Real estate securities include funds invested in commercial and residential real estate properties throughout the U.S. while hedge funds include investments in a number of underlying hedge funds with wide ranging investments, including equity securities of domestic and foreign corporations, U.S. and foreign governments and their agencies, warrants, exchange-traded funds, derivative instruments and private investment funds.

The target allocations for our other post-retirement benefit plan assets are 65% to equity securities and 35% to debt securities. Our investments in equity securities include investments in domestic and foreign large-, mid- and small-cap companies. Our investments in debt securities include a core bond fund with underlying investments in investment grade debt securities of corporate entities, obligations of the U.S. government and its agencies, and cash and cash equivalents.

Similar to other assets measured at fair value, GAAP establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring pension and other post-retirement benefit plan assets at fair value. See Note 4, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management," for a description of the hierarchal framework.

In 2010, we changed our investment advisor for pension assets. As a result, we also changed our investment mix in an attempt to limit the volatility in our benefit obligation. The transition resulted in the sale of all of our then existing level 1 and level 2 investments and the purchase of other level 2 investments. Level 2 pension investments are held in investment funds that are measured using daily net asset values as reported by the fund managers.

We maintain certain level 3 investments in private equity, high-yield bonds, real estate securities and hedge funds 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. Fair value of Level 3 debt instruments are measured using subjective market- and income-based estimates such as projected cash flows and future interest rates. 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. Hedge funds are measured at fair value using net asset values as reported by the underlying hedge fund managers.

The following table provides the fair value of our pension plan assets and the corresponding level of hierarchy as of December 31, 2010 and 2009.

As of December 31, 2010	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ —	$ 117,250	$ 11,575	$ 128,825
International equity	—	44,834	—	44,834
Core bonds	—	183,361	—	183,361
High-yield bonds	—	28,819	1,200	30,019
Real estate securities	—	—	16,411	16,411
Hedge funds	—	—	25,764	25,764
Cash equivalents	—	3,019	—	3,019
Total Assets Measured at Fair Value	$ —	$ 377,283	$ 54,950	$ 432,233

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

The following table provides a reconciliation of pension plan assets measured at fair value using significant level 3 inputs for the years ended December 31, 2010 and 2009.

	Domestic Equity	High-yield Bonds	Real Estate Securities	Hedge Funds	Net Balance
			(In Thousands)		
Balance as of December 31, 2009	$ 9,310	$ 22,519	$ 14,518	$ —	$ 46,347
Actual gain (loss) on plan assets:					
Relating to assets still held at the reporting date	75	(3,963)	2,117	864	(907)
Relating to assets sold during the period	—	4,325	(77)	—	4,248
Purchases, issuances and settlements	2,190	(21,681)	(147)	24,900	5,262
Balance as of December 31, 2010	$ 11,575	$ 1,200	$ 16,411	$ 25,764	$ 54,950
Balance as of January 1, 2009	$ 8,422	$ 16,993	$ 19,985	$ —	$ 45,400
Actual gain (loss) on plan assets:					
Relating to assets still held at the reporting date	(132)	4,991	(5,643)	—	(784)
Relating to assets sold during the period	—	535	176	—	711
Purchases, issuances and settlements	1,020	—	—	—	1,020
Balance as of December 31, 2009	$ 9,310	$ 22,519	$ 14,518	$ —	$ 46,347

The following table provides the fair value of our other post-retirement benefit plan assets and the corresponding level of hierarchy as of December 31, 2010 and 2009.

As of December 31, 2010	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ —	$ 45,766	$ —	$ 45,766
International equity	—	11,280	—	11,280
Core bonds	—	29,938	—	29,938
Total Assets Measured at Fair Value	$ —	$ 86,984	$ —	$ 86,984
As of December 31, 2009				
Assets:				
Domestic equity	$ —	$ 38,648	$ —	$ 38,648
International equity	—	9,674	—	9,674
Core bonds	—	25,792	—	25,792
Total Assets Measured at Fair Value	$ —	$ 74,114	$ —	$ 74,114

Cash Flows

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

Expected Cash Flows	Pension Benefits		Post-retirement Benefits	
	To/(From) Trust	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
		(In Millions)		
Expected contributions:				
2011	$ 49.3	$ 2.0	$ 10.9	$ 0.1
Expected benefit payments:				
2011	$ (28.0)	$ (2.0)	$ (8.4)	$ (0.1)
2012	(29.2)	(2.0)	(8.6)	(0.1)
2013	(31.0)	(2.0)	(9.0)	(0.1)
2014	(33.0)	(2.1)	(9.5)	(0.1)
2015	(35.1)	(2.1)	(9.9)	(0.1)
2016 – 2020	(217.7)	(10.0)	(52.1)	(0.5)

Savings Plans

We maintain a qualified 401(k) savings plan in which most of our employees participate. We match employees' contributions in cash up to specified maximum limits. Our contributions to the plans are deposited with a trustee and invested at the direction of plan participants into one or more of the investment alternatives we provide under the plan. Our contributions totaled $7.4 million in 2010, $6.5 million in 2009 and $6.1 million in 2008.

Stock-Based Compensation Plans

We have a long-term incentive and share award plan (LTISA Plan), which is a stock-based compensation plan in which employees and directors are eligible for awards. The LTISA Plan was implemented as a means to attract, retain and motivate employees and directors. Under the LTISA Plan, we may grant awards in the form of stock options, dividend equivalents, share appreciation rights, RSUs, performance shares and performance share units to plan participants. Up to five million shares of common stock may be granted under the LTISA Plan. As of December 31, 2010, awards of 4,805,179 shares of common stock had been made under the plan.

All stock-based compensation is measured at the grant date based on the fair value of the award and is recognized as an expense in the consolidated statement of income over the requisite service period. The requisite service periods range from one to ten years. The table below shows compensation expense and income tax benefits related to stock-based compensation arrangements that are included in our net income.

	Year Ended December 31,		
	2010	2009	2008
		(In Thousands)	
Compensation expense	$ 11,321	$ 5,080	$ 4,619
Income tax benefits related to stock-based compensation arrangements	4,481	2,011	1,830

We use RSU awards for our stock-based compensation awards. RSU awards are grants that entitle the holder to receive shares of common stock as the awards vest. These RSU awards are defined as nonvested shares and do not include restrictions once the awards have vested. There were no modifications of awards during the years ended December 31, 2010, 2009 or 2008.

RSU awards with only service requirements vest solely upon the passage of time. We measure the fair value of these RSU awards based on the market price of the underlying common stock as of the date of grant. RSU awards with only service conditions that have a graded vesting schedule are recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for the entire award. Nonforfeitable dividend equivalents, or the rights to receive cash equal to the value of dividends paid on Westar Energy's common stock, are paid on these RSUs awarded during the vesting period.

RSU awards with performance measures vest upon expiration of the award term. The number of shares of common stock awarded upon vesting will vary from 0% to 200% of the RSU award, with performance tied to our total shareholder return relative to the total shareholder return of our peer group. We measure the fair value of these RSU awards using a Monte Carlo simulation technique that uses the closing stock price at the valuation date and incorporates assumptions for inputs of the expected volatility and risk-free interest rates. Expected volatility is based on historical volatility over three years using daily stock price observations. The risk-free interest rate is based on treasury constant maturity yields as reported by the Federal Reserve and the length of the performance period. For the 2010 valuation, inputs for expected volatility and risk-free interest rates ranged from 25.2% to 30.1% and 0.3% to 1.4%, respectively. For these RSU awards, dividend equivalents accumulate over the vesting period and are paid in cash based on the number of shares of common stock awarded upon vesting.

During the years ended December 31, 2010, 2009 and 2008, our RSU activity for awards with only service requirements was as follows:

	As of December 31,					
	2010		2009		2008	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value
			(Shares In Thousands)			
Nonvested balance, beginning of year	368.8	$ 21.98	727.4	$ 20.86	984.2	$ 23.11
Granted	366.4	22.14	83.5	18.33	38.7	25.46
Vested	(118.1)	24.81	(439.0)	19.43	(261.3)	28.11
Forfeited	(16.7)	22.32	(3.1)	20.63	(34.2)	35.49
Nonvested balance, end of year	600.4	21.50	368.8	21.98	727.4	20.86

Total unrecognized compensation cost related to RSU awards with only service requirements was $4.8 million as of December 31, 2010. We expect to recognize these costs over a remaining weighted-average period of 1.9 years. The total fair value of RSUs vested and distributed during the years ended December 31, 2010, 2009 and 2008, was $2.7 million, $8.8 million and $6.2 million, respectively.

During the years ended December 31, 2010, 2009 and 2008, our RSU activity for awards with performance measures was as follows:

	As of December 31,					
	2010		2009		2008	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value
	(Shares In Thousands)					
Nonvested balance, beginning of year	—	$ —	—	$ —	—	$ —
Granted	366.0	24.96	—	—	—	—
Vested	(4.5)	23.32	—	—	—	—
Forfeited	(13.1)	24.99	—	—	—	—
Nonvested balance, end of year	348.4	24.98	—	—	—	—

Total unrecognized compensation cost related to RSU awards with performance measures was $4.0 million as of December 31, 2010. We expect to recognize these costs over a remaining weighted-average period of 1.6 years. There were no RSUs vested and distributed during the years ended December 31, 2010, 2009 and 2008.

RSU awards that can be settled in cash upon a change in control are classified as temporary equity. As of December 31, 2010 and 2009, we had temporary equity of $3.5 million and $3.4 million, respectively, on our consolidated balance sheets. If we determine that it is probable that these awards will be settled in cash, the awards will be reclassified as a liability.

Stock options granted between 1998 and 2001 are completely vested and have expired. There were no options exercised and all remaining options were forfeited during the year ended December 31, 2010. We currently have no plans to issue new stock option awards.

Another component of the LTISA Plan is the Executive Stock for Compensation program under which, in the past, eligible employees were entitled to receive deferred common stock in lieu of current cash compensation. Although this plan was discontinued in 2001, dividends will continue to be paid to plan participants on their outstanding plan balance until distribution. Plan participants were awarded 6,627 shares of common stock for dividends in 2010, 7,106 shares in 2009 and 5,283 shares in 2008. Participants received common stock distributions of 1,198 shares in 2010, 563 shares in 2009 and 530 shares in 2008.

Income tax benefits resulting from the income tax deductions in excess of the related compensation cost recognized in the financial statements is classified as cash flows from financing activities in the consolidated statements of cash flows.

12. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Other Post-retirement Benefit Plans

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

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2010	2009	2010	2009
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 111,033	$ 99,536	$ 9,574	$ 8,852
Service cost	4,144	3,643	179	188
Interest cost	6,941	6,401	519	538
Plan participants' contributions	—	—	554	439
Benefits paid	(2,799)	(2,273)	(1,045)	(1,151)
Actuarial losses	12,141	3,726	363	708
Benefit obligation, end of year	$ 131,460	$ 111,033	$ 10,144	$ 9,574
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 62,516	$ 45,201	$ —	$ —
Actual return on plan assets	10,082	12,109	—	—
Employer contribution	6,044	7,310	—	—
Benefits paid	(2,556)	(2,104)	—	—
Fair value of plan assets, end of year	$ 76,086	$ 62,516	$ —	$ —
Funded status, end of year	$ (55,374)	$ (48,517)	$ (10,144)	$ (9,574)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (256)	$ (253)	$ (689)	$ (674)
Noncurrent liability	(55,118)	(48,264)	(9,455)	(8,900)
Net amount recognized	$ (55,374)	$ (48,517)	$ (10,144)	$ (9,574)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 39,735	$ 34,857	$ 3,796	$ 3,709
Prior service cost	47	76	—	—
Transition obligation	52	109	115	173
Net amount recognized	$ 39,834	$ 35,042	$ 3,911	$ 3,882

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2010	2009	2010	2009
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 131,460	$ 111,033	$ —	$ —
Fair value of plan assets	76,086	62,516	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 106,684	$ 90,157	—	—
Fair value of plan assets	76,086	62,516	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 10,144	$ 9,574
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.45%	6.05%	4.90%	5.50%
Compensation rate increase	4.00%	4.00%	—	—

Wolf Creek uses a measurement date of December 31 for its pension and other post-retirement benefit plans. In addition, Wolf Creek uses an interest rate yield curve that is constructed based on the yields on over 500 high-quality, non-callable corporate bonds with maturities between zero and 30 years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of Wolf Creek's pension plan and develop a single-point discount rate matching the plan's payout structure.

The prior service cost is amortized on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. The net actuarial loss subject to amortization is amortized on a straight-line basis over the average future service of active plan participants benefiting under the plan without application of an amortization corridor.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2010	2009	2008	2010	2009	2008
			(Dollars in Thousands)			
Components of Net Periodic Cost:						
Service cost	$ 4,144	$ 3,643	$ 3,421	$ 179	$ 188	$ 203
Interest cost	6,941	6,401	5,680	519	538	517
Expected return on plan assets	(5,453)	(4,976)	(4,709)	—	—	—
Amortization of unrecognized:						
Transition obligation, net	57	57	57	58	58	58
Prior service costs	29	43	57	—	—	—
Actuarial loss, net	2,636	2,538	1,696	276	257	231
Net periodic cost before regulatory adjustment	8,354	7,706	6,202	1,032	1,041	1,009
Regulatory adjustment	(1,498)	(945)	—	—	—	—
Net periodic cost	$ 6,856	$ 6,761	$ 6,202	$ 1,032	$ 1,041	$ 1,009
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$ 7,514	$ (3,407)	$ 21,517	$ 363	$ 708	$ 362
Amortization of actuarial loss	(2,636)	(2,538)	(1,696)	(276)	(257)	(231)
Amortization of prior service cost	(29)	(43)	(57)	—	—	—
Amortization of transition obligation	(57)	(57)	(57)	(58)	(58)	(58)
Total recognized in regulatory assets	$ 4,792	$ (6,045)	$ 19,707	$ 29	$ 393	$ 73
Total recognized in net periodic cost and regulatory assets	$ 11,648	$ 716	$ 25,909	$ 1,061	$ 1,434	$ 1,082
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:						
Discount rate	6.05%	6.15%	6.15%	5.50%	6.05%	6.05%
Expected long-term return on plan assets	8.00%	8.00%	8.25%	—	—	—
Compensation rate increase	4.00%	4.00%	4.00%	—	—	—

We estimate that we will amortize the following amounts from regulatory assets into net periodic cost in 2011.

	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 3,664	$ 281
Prior service cost	16	—
Transition obligation	52	58
Total	$ 3,732	$ 339

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

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

	As of December 31,	
	2010	2009
Health care cost trend rate assumed for next year	8.0%	8.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2018	2018

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

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(In Thousands)	
Effect on total of service and interest cost	$ (8)	$ 8
Effect on the present value of the projected benefit obligation	(85)	79

Plan Assets

The Wolf Creek pension plan investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. Investments are diversified across classes, sectors and manager style to maximize returns and minimize the risk of large losses. Wolf Creek delegates investment management to specialists in each asset class and, where appropriate, provides the investment managers with specific guidelines, which include allowable and/or prohibited investment types. Prohibited investments include investments in the equity or debt securities of the companies that collectively own Wolf Creek or companies that control such companies, which includes our and KGE securities. Wolf Creek has also established restrictions for certain classes of plan assets including that international equity securities should not exceed 25% of total plan assets, no more than 5% of the market value of the plan assets should be invested in the common stock of one corporation and the equity investment in any one corporation should not exceed 1% of its outstanding common stock. Wolf Creek does not utilize a separate investment trust for the purpose of funding other post-retirement benefits as it does for its pension plan.

The target allocations for Wolf Creek's pension plan assets are 22% to international equity securities, 43% to domestic equity securities, 25% to debt securities, 5% to real estate securities and 5% to commodity investments. The investments in both international and domestic equity securities include investments in large-, mid- and small-cap companies, private equity funds and investment funds with underlying investments similar to those previously mentioned. The investments in debt securities include core and high-yield bonds. Core bonds include funds invested in investment grade debt securities of corporate entities, obligations of U.S. and foreign governments and their agencies, and private debt securities. High-yield bonds include a fund with underlying investments in non-investment grade debt securities of corporate entities, private placements and bank debt. Real estate securities include funds invested in commercial and residential real estate properties while commodity investments include funds invested in commodity-related instruments.

Wolf Creek's investments in equity, debt and commodity instruments are recorded at fair value using quoted market prices or valuation models utilizing observable market data when available. A portion of the investments is comprised of real estate securities that require significant unobservable market information to measure the fair value of the investments. Real estate securities are measured at fair value using a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity.

Similar to other assets measured at fair value, GAAP establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring pension and other post-retirement benefit plan assets at fair value. From time to time, the pension and post-retirement trusts may buy and sell investments resulting in changes within the hierarchy. See Note 4, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management," for a description of the hierarchal framework.

The following table provides the fair value of KGE's 47% share of Wolf Creek's pension plan assets and the corresponding level of hierarchy as of December 31, 2010 and 2009.

As of December 31, 2010	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ 31,492	$ —	$ —	$ 31,492
International equity	9,036	9,597	—	18,633
Core bonds	—	14,156	—	14,156
High-yield bonds	3,319	—	—	3,319
Real estate securities	—	—	3,160	3,160
Commodities	—	4,558	—	4,558
Cash equivalents	1	767	—	768
Total Assets Measured at Fair Value	$ 43,848	$ 29,078	$ 3,160	$ 76,086

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

The following table provides a reconciliation of KGE's 47% share of Wolf Creek's pension plan assets measured at fair value using significant level 3 inputs for the years ended December 31, 2010 and 2009.

	Real Estate Securities (In Thousands)
Balance as of December 31, 2009	$ 2,416
Actual gain (loss) on plan assets:	
Relating to assets still held at the reporting date	393
Relating to assets sold during the period	(2)
Purchases, issuances and settlements	353
Balance as of December 31, 2010	$ 3,160
Balance as of January 1, 2009	$ —
Actual gain (loss) on plan assets:	
Relating to assets still held at the reporting date	(370)
Relating to assets sold during the period	6
Purchases, issuances and settlements	2,780
Balance as of December 31, 2009	$ 2,416

Cash Flows

The following table shows our expected cash flows for KGE's 47% share of Wolf Creek's pension and other post-retirement benefit plans for future years.

Expected Cash Flows	Pension Benefits		Post-retirement Benefits	
	To/(From) Trust	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
	(In Millions)			
Expected contributions:				
2011	$ 11.0	$ 0.2	$ —	$ 0.7
Expected benefit payments:				
2011	$ (2.7)	$ (0.2)	$ —	$ (0.7)
2012	(3.1)	(0.2)	—	(0.7)
2013	(3.7)	(0.2)	—	(0.8)
2014	(4.2)	(0.2)	—	(0.8)
2015	(4.9)	(0.2)	—	(0.8)
2016 – 2020	(37.8)	(1.1)	—	(4.2)

Savings Plan

Wolf Creek maintains a qualified 401(k) savings plan in which most of its employees participate. They match employees' contributions in cash up to specified maximum limits. Wolf Creek's contributions to the plan are deposited with a trustee and invested at the direction of plan participants into one or more of the investment alternatives provided under the plan. KGE's portion of the expense associated with Wolf Creek's matching contributions was $1.1 million in 2010, $1.1 million in 2009 and $1.0 million in 2008.

13. COMMITMENTS AND CONTINGENCIES

Purchase Orders and Contracts

As part of our ongoing operations and capital expenditure program, we have purchase orders and contracts, excluding fuel, which is discussed below under "– Purchased Power and Fuel Commitments," that had an unexpended balance of approximately $671.2 million as of December 31, 2010, of which $427.7 million had been committed. The $427.7 million of commitments relates to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments as of December 31, 2010, was as follows.

	Committed Amount
	(In Thousands)
2011	$ 268,496
2012	76,169
2013	47,895
Thereafter	35,164
Total amount committed	$ 427,724

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 pollutants 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 pollutants 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.

The environmental cost recovery rider (ECRR) allows for the more timely inclusion in retail prices the costs of capital expenditures associated with environmental improvements, including those required by the Federal Clean Air Act. In order to change our prices to recognize increased operating and maintenance costs, however, we must file a general rate case with the KCC. A recent order of the KCC indicated that it may be more appropriate to recover environmental costs at La Cygne through the filing of a general rate case as opposed to the ECRR. This could increase the time between making these investments and having them reflected in the prices we charge our customers, as well as the amount we charge our customers. Our anticipated capital expenditures at La Cygne for environmental equipment for 2011 through 2013 are $429.1 million.

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 Clear 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 MW of qualifying wind generation facilities, which together with the use of renewable energy credits, we expect to meet the 2011 requirement. On December 14, 2010, we announced that we reached two separate agreements with third parties, subject to regulatory approval, to purchase under 20-year supply contracts the renewable energy produced from approximately 370 MW of wind generation beginning in late 2012. We expect these agreements, along with our prior development of wind generation facilities, will satisfy our net renewable generation requirement through 2015 and contribute toward meeting the increased requirement beginning in 2016.

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 with ONEOK Inc. (ONEOK), the current owner of some of the sites, ONEOK assumed total liability for remediation of seven sites and we share liability for remediation with ONEOK for five sites. Our total liability for the five shared sites is capped at $3.8 million.

Our environmental liability for remediation of former manufactured gas sites in Missouri associated with assets we divested many years ago had been limited to $7.5 million by the terms of an environmental indemnity agreement with the purchaser of those assets. In June 2010, the purchaser agreed to reduce our maximum liability to $2.5 million, which reflects our share of the purchaser's expected remediation costs. We have settled this liability.

EPA Lawsuit

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

In January 2004, the EPA notified us that certain projects completed at JEC violated certain requirements of the New Source Review program. In February 2009, the Department of Justice, on behalf of the EPA, filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. On January 25, 2010, we announced a settlement of the lawsuit. The settlement was filed with the court, seeking its approval, and on March 26, 2010, the court entered an order approving the settlement. The settlement requires that we 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. This amount could change materially depending on final engineering and design. 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 NOx reduction targets. Recovery of costs to install these systems is subject to the approval of our regulators. We believe these costs are appropriate for inclusion in the prices we are allowed to charge our customers. We will also invest $5.0 million over six years in environmental mitigation projects that we will own. In 2009, we recorded as part of the settlement $1.0 million for environmental mitigation projects that will be owned by a qualifying third party and a $3.0 million civil penalty.

FERC Investigation

We continue to respond to a non-public investigation by FERC of our use of transmission service between July 2006 and February 2008. On May 7, 2009, FERC staff advised us that it had preliminarily concluded that we improperly used secondary network transmission service to facilitate off-system wholesale power sales in violation of applicable FERC orders and Southwest Power Pool (SPP) tariffs. FERC staff alleged we received $14.3 million of unjust profits through such activities. We sent a response to FERC staff disputing both the legal basis for its allegations and their factual underpinnings. Based on our response, FERC staff 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. On March 4, 2010, we sent a response to FERC staff disputing its revised conclusions. 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 potentially could alter the manner in which we are permitted to buy and sell energy and use transmission service.

Nuclear Decommissioning

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

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

The KCC approved Wolf Creek's most recent nuclear decommissioning site study in August 2009. Based on the study, our share of decommissioning costs, including decontamination, dismantling and site restoration, is estimated to be $279.0 million. This amount compares to the prior site study estimate of $243.3 million. The site study cost estimate represents the estimate to decommission Wolf Creek as of the site study year. The actual nuclear decommissioning costs may vary from the estimates because of changes in regulations and technologies as well as changes in costs for labor, materials and equipment.

We are allowed to recover nuclear decommissioning costs in our prices over a period equal to the operating license of Wolf Creek, which is through 2045. The NRC requires that funds sufficient to meet nuclear decommissioning obligations be held in trust. We believe that the KCC approved funding level will also be sufficient to meet the NRC requirement. Our consolidated financial results would be materially adversely affected if we were not allowed to recover in our prices the full amount of the funding requirement.

We recovered in our prices and deposited in an external trust fund for nuclear decommissioning approximately $3.1 million in 2010 and $2.9 million in both 2009 and 2008. We record our investment in the NDT fund at fair value, which approximated $127.0 million as of December 31, 2010, and $112.3 million as of December 31, 2009.

Storage of Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee, calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers, was $4.0 million in 2010, $3.7 million in 2009 and $3.5 million in 2008. We include these costs in fuel and purchased power expense on our consolidated statements of income.

In March 2010, the DOE filed a motion to withdraw its application with the NRC to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada, which would end the licensing process. An NRC board denied the DOE's motion to withdraw its application in June 2010 and the DOE appealed that decision to the full NRC in early July 2010. The NRC has not yet decided that appeal. The question of the DOE's legal authority to withdraw its license application also is pending in multiple lawsuits filed with a federal appellate court. Oral argument to the court is set for late March 2011. Wolf Creek has an on-site storage facility designed to hold all spent fuel generated at the plant through 2025 and believes it will be able to expand on-site storage as needed past 2025. We cannot predict when, or if, an alternative disposal site will be available to receive Wolf Creek's spent nuclear fuel and will continue to monitor this activity.

Nuclear Insurance

We maintain nuclear insurance for Wolf Creek in four areas: liability, worker radiation, property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear and war. The nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry no longer include industry aggregate limits for non-certified acts, as defined by the Terrorism Risk Insurance Act, of terrorism-related losses, including replacement power costs. An industry aggregate limit of $3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), our insurance provider, exists for property claims, including accidental outage power costs, for acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within twelve months from the date of the first act. These limits are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. In addition, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, which has been reauthorized through December 31, 2025, by the Energy Policy Act of 2005, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently approximately \$12.6 billion. This limit of liability consists of the maximum available commercial insurance of \$375.0 million, and the remaining \$12.2 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, the owners of Wolf Creek are jointly and severally subject to an assessment of up to \$117.5 million (our share is \$55.2 million), payable at no more than \$17.5 million (our share is \$8.2 million) per incident per year per reactor. Both the total and yearly assessment is subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. This assessment also applies in excess of our worker radiation claims insurance. The next scheduled inflation adjustment is scheduled for August 2013. In addition, Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property Insurance

The owners of Wolf Creek carry decontamination liability, premature nuclear decommissioning liability and property damage insurance for Wolf Creek totaling approximately \$2.8 billion (our share is \$1.3 billion). This insurance is provided by NEIL. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the NRC. Our share of any remaining proceeds can be used to pay for property damage, decontamination expenses or, if certain requirements are met, including nuclear decommissioning the plant, toward a shortfall in the NDT fund.

Accidental Nuclear Outage Insurance

The owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, we may be subject to retrospective assessments under the current policies of approximately \$26.2 million (our share is \$12.3 million).

Although we maintain various insurance policies to provide coverage for potential losses and liabilities resulting from an accident or an extended outage, our insurance coverage may not be adequate to cover the costs that could result from a catastrophic accident or extended outage at Wolf Creek. Any substantial losses not covered by insurance, to the extent not recoverable in our prices, would have a material adverse affect on our consolidated financial results.

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements for our power plants, the owners of Wolf Creek have entered into various commitments to obtain nuclear fuel and we have entered into various commitments to obtain coal and natural gas. Some of these contracts contain provisions for price escalation and minimum purchase commitments. As of December 31, 2010, our share of Wolf Creek's nuclear fuel commitments was approximately \$45.3 million for uranium concentrates expiring in 2017, \$6.9 million for conversion expiring in 2017, \$116.6 million for enrichment expiring in 2024 and \$44.7 million for fabrication expiring in 2024.

As of December 31, 2010, our coal and coal transportation contract commitments in 2010 dollars under the remaining terms of the contracts were approximately \$1.5 billion. The two largest contracts expire in 2013 and 2020, with the remaining contracts expiring at various times through 2020.

As of December 31, 2010, our natural gas transportation contract commitments in 2010 dollars under the remaining terms of the contracts were approximately \$179.8 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2030.

We have purchase power agreements with the owners of two separate wind generation facilities located in Kansas with a combined capacity of 146 MW. The agreements expire in late 2028 and early 2029 and provide for our receipt and purchase of the energy produced at a fixed price per unit of output. We estimate that our annual cost for energy purchased from these wind generation facilities will be approximately \$19.5 million.

14. ASSET RETIREMENT OBLIGATIONS

Legal Liability

We have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. The recording of AROs for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset.

We initially recorded AROs at fair value for the estimated cost to decommission Wolf Creek (KGE's 47% share), retire our wind generating facilities, dispose of asbestos insulating material at our power plants, remediate ash disposal ponds and dispose of polychlorinated biphenyl (PCB)-contaminated oil.

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Beginning ARO	$ 119,519	$ 95,083
Liabilities incurred	—	1,289
Liabilities settled	(738)	(1,922)
Accretion expense	7,218	4,727
Increase in nuclear decommissioning ARO liability	—	20,342
Ending ARO	$ 125,999	$ 119,519

As discussed in Note 13, "Commitments and Contingencies – Nuclear Decommissioning," Wolf Creek filed a nuclear decommissioning study with the KCC in 2009. As a result of the study, we recorded a $20.3 million increase in our ARO to reflect revisions to the estimated costs to decommission Wolf Creek.

Conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. We determined that our conditional AROs include the retirement of our wind generation facilities, disposal of asbestos insulating material at our power plants, the remediation of ash disposal ponds and the disposal of PCB-contaminated oil.

We have an obligation to retire our wind generation facilities and remove the foundations. The ARO related to our wind generation facilities was determined based upon the date each wind generation facility was placed into service.

The amount of the retirement obligation related to asbestos disposal was recorded as of 1990, the date when the EPA published the "National Emission Standards for Hazardous Air Pollutants: Asbestos NESHAP Revision; Final Rule."

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

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

Non-Legal Liability – Cost of Removal

We recover in our prices the costs to dispose of plant assets that do not represent legal retirement obligations. As of December 31, 2010 and 2009, we had $70.3 million and $68.1 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability.

15. 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. As of December 31, 2010, we had accrued liabilities of $80.6 million for compensation not yet paid to them and $8.3 million for legal fees and expenses they had incurred. As of December 31, 2009, we had accrued liabilities of $77.6 million for compensation not yet paid to them and $6.8 million for legal fees and expenses they had incurred. The arbitration was stayed in August 2004 pending final resolution of criminal charges filed by the United States Attorney's Office against them in U.S. District Court in the District of Kansas. In August 2010, these criminal charges were dismissed and subsequently the stay of the arbitration was lifted. We expect arbitration proceedings to conclude in 2011. We have reclassified about $54.0 million, comprised of various elements of compensation, from other long-term liabilities to other current liabilities on our consolidated balance sheet. We intend to vigorously defend against the counterclaims they filed in the arbitration. We are unable to predict the ultimate amount of the compensation, legal fees or related amounts we may be required to pay them, or the ultimate impact of these matters on our consolidated financial results.

We and our subsidiaries are involved in various other legal, environmental and regulatory proceedings. We believe that adequate provisions have been made and accordingly believe that the ultimate disposition of such matters will not have a material adverse affect on our consolidated financial results.

See also Note 3, "Rate Matters and Regulation," and Note 13, "Commitments and Contingencies."

16. COMMON AND PREFERRED STOCK

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

	Cumulative preferred stock shares	Common stock shares
Balance at December 31, 2007	214,363	95,463,180
Issuance of common stock...........	—	12,847,955
Balance at December 31, 2008	214,363	108,311,135
Issuance of common stock...........	—	760,865
Balance at December 31, 2009	214,363	109,072,000
Issuance of common stock...........	—	3,056,068
Balance at December 31, 2010	214,363	112,128,068

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. As of December 31, 2010, we had 112,128,068 shares issued and outstanding.

Westar Energy has a direct stock purchase plan (DSPP). Shares sold pursuant to the DSPP may be either original issue shares or shares purchased in the open market. During 2010, 2009 and 2008, Westar Energy issued 734,918 shares, 760,865 shares and 592,772 shares, respectively, through the DSPP and other stock-based plans operated under the 1996 LTISA Plan. As of December 31, 2010 and 2009, a total of 2,590,942 shares and 3,196,816 shares, respectively, were available under the DSPP registration statement.

Common Stock Issuance

Through a Sales Agency Financing Agreement entered into with a broker dealer subsidiary of a bank in 2007, Westar Energy sold 1.2 million shares of common stock for $25.0 million in 2010 and 1.1 million shares of common stock for $26.9 million in 2008. Westar Energy did not sell any shares of common stock under this agreement during 2009.

During 2010, Westar Energy entered into two separate forward sale agreements with banks. The use of a forward sale agreement allows Westar Energy the means to minimize equity market uncertainty by pricing a common stock offering under then existing market conditions while mitigating share dilution by postponing the issuance of common stock until funds are needed. Westar Energy is also better able to match the timing of its financing needs with its capital investment and regulatory plans. The forward sale transactions are entered into at market prices; therefore, the forward sale agreements have no initial fair value. Westar Energy will not receive any proceeds from the sale of common stock under the forward sale agreements until transactions are settled. Upon settlement, Westar Energy will record the forward sale agreements within equity. Except in specified circumstances or events that would require physical share settlement, Westar Energy is able to elect to settle any forward sale transactions by means of physical share, cash or net share settlement, and is also able to elect to settle the forward sale transactions in whole, or in part, earlier than the stated maturity dates. Currently, Westar Energy anticipates settling the forward sale transactions through physical share settlement. The shares under the forward sale agreements were initially priced when the agreements were entered into and are subject to certain fixed pricing adjustments during the term of the agreements. Accordingly, assuming physical share settlement, Westar's net proceeds from the forward sale transactions will represent the prices established by the forward sale agreements applicable to the time periods in which physical settlement occurs.

Westar Energy entered into one such forward sale agreement on November 4, 2010. Under the terms of the agreement, the bank, as forward seller, borrowed 7.5 million shares of Westar Energy's common stock from third parties and sold them to a group of underwriters for $25.54 per share. Under an over-allotment option included in the agreement, the underwriters purchased approximately 1.0 million additional shares on November 5, 2010, also for $25.54 per share, which increased the total number of shares under the forward sale agreement to approximately 8.5 million shares. The underwriters receive a commission equal to 3.5% of the sales price of all shares sold under the agreement. Westar Energy must settle the forward sale agreement within 18 months of the transaction date. Assuming physical share settlement of this agreement at December 31, 2010, Westar Energy would have received aggregate proceeds of approximately $206.2 million, net of commission, based on an average forward price of $24.32 per share.

On April 2, 2010, Westar Energy entered into a new, three-year Sales Agency Financing Agreement and forward sale agreement. The maximum amount that Westar Energy may offer and sell under the agreements is the lesser of an aggregate of $500.0 million or approximately 22.0 million shares, subject to adjustment for share splits, share combinations and share dividends. Under the terms of the Sales Agency Financing Agreement, Westar Energy may offer and sell shares of its common stock from time to time through the broker dealer subsidiary, as agent. The broker dealer receives a commission equal to 1% of the sales price of all shares sold under the agreement. In addition, under the terms of the Sales Agency Financing Agreement and forward sale agreement, Westar Energy may from time to time enter into one or more forward sale transactions with the bank, as forward purchaser, and the bank will borrow shares of Westar Energy's common stock from third parties and sell them through its broker dealer. Westar Energy must settle the forward sale transactions within a year of the date each transaction is entered. As of December 31, 2010, Westar Energy had entered into forward sale transactions with respect to an aggregate of approximately 5.4 million shares of common stock. As partial settlement of the forward sale transactions, Westar Energy delivered approximately 0.5 million shares of common stock for proceeds of $10.4 million on October 14, 2010. On December 20, 2010, Westar Energy delivered approximately 0.7 million additional shares for proceeds of $16.0 million as partial settlement of the forward sale transactions. Assuming physical share settlement of the approximately 4.2 million remaining shares of common stock at December 31, 2010, Westar Energy would have received aggregate proceeds of approximately $94.0 million, net of commission, based on an average forward price of $22.16 per share.

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

In 2008, Westar Energy also completed a forward sale agreement entered into in November 2007 by delivering 5.1 million shares of common stock for proceeds of $123.0 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.

Preferred Stock Not Subject to Mandatory Redemption

Westar Energy's cumulative preferred stock is redeemable in whole or in part on 30 to 60 days' notice at our option. The table below shows our redemption amount for all series of preferred stock not subject to mandatory redemption as of December 31, 2010.

Rate	Shares	Principal Outstanding	Call Price	Premium	Total Cost to Redeem
		(Dollars in Thousands)			
4.500%	121,613	$12,161	108.0%	$ 973	$13,134
4.250%	54,970	5,497	101.5%	82	5,579
5.000%	37,780	3,778	102.0%	76	3,854
		$21,436		$1,131	$22,567

The provisions of Westar Energy's articles of incorporation, as amended, contain restrictions on the payment of dividends or the making of other distributions on its common stock while any preferred shares remain outstanding unless certain capitalization ratios and other conditions are met. If the ratio of the capital represented by Westar Energy's common stock, including premiums on its capital stock and its surplus accounts, to its total capital and its surplus accounts at the end of the second month immediately preceding the date of the proposed payment of dividends, adjusted to reflect the proposed payment (capitalization ratio), will be less than 20%, then the payment of the dividends on its common stock, including the proposed payment, during the 12-month period ending with and including the date of the proposed payment shall not exceed 50% of its net income available for dividends for the 12-month period ending with and including the second month immediately preceding the date of the proposed payment. If the capitalization ratio is 20% or more but less than 25%, then the payment of dividends on its common stock, including the proposed payment, during the 12-month period ending with and including the date of the proposed payment shall not exceed 75% of its net income available for dividends for the 12-month period ending with and including the second month immediately preceding the date of the proposed payment. Except to the extent permitted above, no payment or other distribution may be made that would reduce the capitalization ratio to less than 25%. The capitalization ratio is determined based on the unconsolidated balance sheet for Westar Energy. As of December 31, 2010, the capitalization ratio was greater than 25%.

So long as there are any outstanding shares of Westar Energy preferred stock, Westar Energy shall not without the consent of a majority of the shares of preferred stock or if more than one-third of the outstanding shares of preferred stock vote negatively and without the consent of a percentage of any and all classes required by law and Westar Energy's articles of incorporation, declare or pay any dividends (other than stock dividends or dividends applied by the recipient to the purchase of additional shares) or make any other distribution upon common stock unless, immediately after such distribution or payment the sum of Westar Energy's capital represented by its outstanding common stock and its earned and any capital surplus shall not be less than $10.5 million plus an amount equal to twice the annual dividend requirement on all the then outstanding shares of preferred stock.

17. VARIABLE INTEREST ENTITIES

Effective January 1, 2010, we adopted accounting guidance that amends the consolidation criteria for VIEs. The amended guidance requires a qualitative assessment rather than a quantitative assessment in determining the primary beneficiary of a VIE. A qualitative assessment includes understanding 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. We have concluded that trusts holding assets we lease, which include the 8% interest in JEC, the 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. With the consolidation of these VIEs, we ceased accounting for these transactions as leases. See Note 18, "Leases," for additional information.

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 such 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

As of December 31, 2010, we had recorded the following assets and liabilities on our consolidated balance sheet as a result of consolidating the VIEs described above.

As of December 31, 2010		Dollar Amount (In Thousands)
Assets:		
Property, plant and equipment of variable interest entities, net	$	345,037
Regulatory assets (a)		3,963
Liabilities:		
Current maturities of long-term debt of variable interest entities	$	30,155
Accrued interest (b)		5,064
Long-term debt of variable interest entities, net		278,162

(a) Included in other regulatory assets on our consolidated balance sheet.
(b) Included in accrued interest on our consolidated balance sheet.

All of the liabilities noted in the table above relate to the purchase 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.

Additionally, the consolidation of these VIEs affected the presentation of our consolidated statements of cash flows. A portion of lease expenditures previously presented as operating cash flows is now allocated between operating and financing cash flows. Total cash flows did not change.

18. LEASES

As discussed in Note 17, "Variable Interest Entities," the adoption of new accounting guidance effective January 1, 2010, eliminated the lease accounting we previously reported for 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. As a result, future commitments under operating leases, minimum annual rental payments under capital leases and recorded capital lease assets have decreased significantly. However, we remain contractually obligated to meet our future commitments and to make annual payments in accordance with the lease agreements that relate to these assets.

Operating Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment. These leases have various terms and expiration dates ranging from one to 20 years.

In determining lease expense, we recognize the effects of scheduled rent increases on a straight-line basis over the minimum lease term. The rental expense and estimated future commitments under operating leases are as follows.

Year Ended December 31,	Total Operating Leases
	(In Thousands)
Rental expense:	
2008	$ 38,870
2009	38,096
2010	15,464
Future commitments:	
2011	$ 12,940
2012	14,192
2013	11,973
2014	9,996
2015	7,879
Thereafter	21,936
Total future commitments	$ 78,916

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.

Assets recorded under capital leases are listed below.

	December 31,	
	2010	2009
	(In Thousands)	
Vehicles	$ 12,504	$ 18,991
Computer equipment and software	5,551	4,640
JEC 8% interest (a)	—	118,623
Accumulated amortization	(8,744)	(21,736)
Total capital leases	$ 9,311	$ 120,518

(a) As discussed in Note 17, "Variable Interest Entities," the adoption of new accounting guidance effective January 1, 2010, eliminated the lease accounting we previously reported for our 8% interest in JEC.

Capital lease payments 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.

Year Ended December 31,	Total Capital Leases (In Thousands)
2011	$ 2,110
2012	2,213
2013	1,908
2014	1,792
2015	1,391
Thereafter	1,157
	10,571
Amounts representing imputed interest	(1,260)
Present value of net minimum lease payments under capital leases	9,311
Less: current portion	1,797
Total long-term obligation under capital leases	$ 7,514

19. DISCONTINUED OPERATIONS — Sale of Protection One, Inc.

In January 2009, the Joint Committee on Taxation of the U.S. Congress approved a settlement with the IRS Office of Appeals regarding the re-characterization of a portion of the loss we incurred on the sale of Protection One, Inc. (Protection One), a former subsidiary, from a capital loss to an ordinary loss. The settlement involved a determination of the amount of the net capital loss and net operating loss carryforwards available as of December 31, 2004, to offset income in years after 2004. In March 2009, we filed amended federal income tax returns for years 2005, 2006 and 2007 to claim a portion of the income tax benefits from the net operating loss carryforward. We expect to realize the remainder of the income tax benefits from the net operating loss carryforward in future years. We recorded a non-cash net earnings benefit of approximately $33.7 million, net of $22.8 million we paid Protection One, in discontinued operations in 2009 in recognition of this settlement.

20. QUARTERLY RESULTS (UNAUDITED)

Our electric business is seasonal in nature and, in our opinion, comparisons between the quarters of a year do not give a true indication of overall trends and changes in operations.

2010	First	Second	Third (a)	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues (b)	$ 459,830	$495,181	$ 644,437	$ 456,723
Net income (b)	31,682	54,530	115,863	6,550
Net income attributable to common stock (b)	30,438	53,069	114,502	4,919
Per Share Data (b):				
Basic:				
Earnings available	$ 0.27	$ 0.47	$ 1.02	$ 0.04
Diluted:				
Earnings available	$ 0.27	$ 0.47	$ 1.01	$ 0.04
Cash dividend declared per common share	$ 0.31	$ 0.31	$ 0.31	$ 0.31
Market price per common share:				
High	$ 22.78	$ 23.93	$ 24.64	$ 25.90
Low	$ 20.56	$ 21.08	$ 21.22	$ 24.21

(a) In the third quarter of 2010, net income and net income attributable to common stock increased compared to the same period last year due principally to warmer than normal weather in our service territory paired with extremely cool weather during the third quarter of 2009. As measured by cooling degree days, the weather during the third quarter of 2010 was 63% warmer than the same period last year and 20% warmer than the 20-year average.

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

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

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

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

Westar Energy, Inc. **Attachment B(6)**

Ringfencing Compliance Filing

May 31, 2011

Report requirements:

B. Each jurisdictional public utility shall provide annually by May 31st the following information using diagrams, schedules or narrative discussion as may be appropriate:

6. To the extent financial separations are maintained for either legal or financial accounting purposes and at a level in which financial statements are reasonably capable of being produced by the utility's accounting system, each jurisdictional public utility shall file a summary of financial ratios as of the end of the last completed fiscal year, as described by way of example in the attachment to these rules and consistent with the method used to report such information to the principal bond rating agency or Standard & Poors for (1) consolidated utility operations; (2) consolidated non-regulated operations; and (3) consolidated corporate financials.

Westar Energy Response:

A responsive summary of financial ratios for Westar Energy, Inc. (consolidated), Westar Energy, Inc. (standalone) and Kansas Gas and Electric Company are attached. Pursuant to the exception stated on Page 4 of the Report regarding entities comprising less than 10% of the consolidated assets or 10% of the consolidated revenues of the parent jurisdictional public utility, financial ratios regarding consolidated non-regulated operations are not attached.

Westar Energy, Inc. Consolidated

Summary of Consolidated Entity Financial Ratios For Fiscal Year Ending 12-31-2010	
Ratio Description	**Westar Ratio**
Total Debt to Total Capitalization	57.1 %
Funds from Operations Interest Coverage	4.2 X
Funds from Operations as a Percent of Total Debt	21.4 %

Westar Energy, Inc. Standalone

Summary of Westar Stand-Alone Financial Ratios For Fiscal Year Ending 12-31-2010*	
Ratio Description	**Westar Ratio**
Total Debt to Total Capitalization	43.7 %
Funds from Operations Interest Coverage	5.4 X
Funds from Operations as a Percent of Total Debt	24.2 %

Kansas Gas and Electric Company

Summary of KGE Stand-Alone Financial Ratios For Fiscal Year Ending 12-31-2010*	
Ratio Description	**Westar Ratio**
Total Debt to Total Capitalization	49.7 %
Funds from Operations Interest Coverage	3.3 X
Funds from Operations as a Percent of Total Debt	15.8 %

* The Westar and KGE stand-alone ratios are being calculated and provided specifically for purposes of meeting the Commission's ringfencing information submittal requirements. These stand-alone ratios are not calculated in the normal course of business and they are not provided to any rating agency.