$1,500,000,000

Kentucky Utilities Company

$250,000,000 1.625% First Mortgage Bonds due 2015
$500,000,000 3.250% First Mortgage Bonds due 2020
$750,000,000 5.125% First Mortgage Bonds due 2040

Kentucky Utilities Company is hereby offering $250,000,000 of First Mortgage Bonds, 1.625% Series due 2015 (the "2015 Bonds"), $500,000,000 of First Mortgage Bonds, 3.250% Series due 2020 (the "2020 Bonds") and $750,000,000 of First Mortgage Bonds, 5.125% Series due 2040 (the "2040 Bonds" and, together with the 2015 Bonds and the 2020 Bonds, the "Bonds"). Interest on the Bonds is payable on May 1 and November 1 of each year, beginning on May 1, 2011. The 2015 Bonds will mature on November 1, 2015, the 2020 Bonds will mature on November 1, 2020 and the 2040 Bonds will mature on November 1, 2040. We may redeem some or all of the Bonds at our option, in whole at any time or in part from time to time, at the redemption prices set forth in this offering memorandum under "Description of the Bonds — Redemption." The Bonds will be issued in minimum denominations of $2,000 and in multiples of $1,000 in excess thereof.

Each series of Bonds will be our senior secured indebtedness and will rank equally with all of our other outstanding senior secured indebtedness from time to time outstanding and issued under our 2010 mortgage indenture, as described in "Description of the Bonds — Security; Lien of the Mortgage" herein.

Investing in the Bonds involves certain risks. See "Risk Factors" beginning on page 7 of this offering memorandum.

Price per 2015 Bond: 99.650% plus accrued interest, if any, from November 16, 2010
Price per 2020 Bond: 99.622% plus accrued interest, if any, from November 16, 2010
Price per 2040 Bond: 98.915% plus accrued interest, if any, from November 16, 2010

The Bonds have not been registered under the Securities Act of 1933, as amended (the "Securities Act"), or any state securities laws. Accordingly, the Bonds are being offered and sold only to "qualified institutional buyers" in accordance with Rule 144A under the Securities Act and outside the United States to non-U.S. persons in accordance with Regulation S under the Securities Act. Prospective purchasers that are qualified institutional buyers are hereby notified that the seller of the Bonds may be relying on the exemption from the provisions of Section 5 of the Securities Act provided by Rule 144A. For a description of certain restrictions on transfers of the Bonds, see "Transfer Restrictions" and "Plan of Distribution." The Bonds will not be listed on any securities exchange.

We will enter into a registration rights agreement pursuant to which we will agree to file a registration statement with the U.S. Securities and Exchange Commission relating to an offer to exchange the Bonds for publicly tradable securities having substantially identical terms. See "Registration Rights Agreement" for a description of this commitment.

The initial purchasers expect to deliver the Bonds to purchasers in book-entry form only through the facilities of The Depository Trust Company ("DTC") and its participants, on or about November 16, 2010.

Joint Book-Running Managers

BofA Merrill Lynch **RBS** **Credit Suisse**

BNP PARIBAS **Mitsubishi UFJ Securities** **Scotia Capital**

Co-Managers

BBVA Securities **RBC Capital Markets** **Santander**

SunTrust Robinson Humphrey **The Williams Capital Group, L.P.**

The date of this offering memorandum is November 8, 2010.

In making your investment decision, you should rely only on the information contained in this offering memorandum and in any communication from us or the initial purchasers specifying the final terms of the offering. Neither we nor the initial purchasers have authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the initial purchasers are not, making an offer of the Bonds in any jurisdiction where the offer thereof is not permitted. The information contained in this offering memorandum speaks only as of the date of this offering memorandum.

References to the "Company," "we," "us" and "our" in this offering memorandum are references to Kentucky Utilities Company specifically or, if the context requires, to Kentucky Utilities Company and its subsidiaries, collectively. The term "initial purchasers" refers to Credit Suisse Securities (USA) LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated and the other initial purchasers listed in "Plan of Distribution."

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We have prepared this offering memorandum solely for use in connection with the proposed sale of the Bonds described herein. The Company and the initial purchasers reserve the right to reject any offer to purchase, in whole or in part, for any reason, or to sell less than the amount of Bonds offered hereby. This offering memorandum is personal to each offeree and does not constitute an offer to any other person or to the public generally to subscribe for or otherwise acquire securities. This offering memorandum is a confidential document which we are providing only to prospective buyers of the Bonds in places where sales are permitted and not otherwise deemed unlawful. Distribution of this offering memorandum to any person other than the prospective investor and any person retained to advise such prospective investor with respect to its purchase is unauthorized, and any disclosure of any of the contents of this offering memorandum, without our prior written consent, is prohibited. Each prospective investor, by accepting delivery of this offering memorandum, agrees to the foregoing and agrees further not to make any photocopies of this offering memorandum, and if a prospective investor does not purchase Bonds or the offering is terminated, to destroy or return this offering memorandum to Kentucky Utilities Company, One Quality Street, Lexington, Kentucky 40507, Attention: Corporate Secretary.

We have prepared this offering memorandum and we are solely responsible for its contents. You are responsible for making your own examination of the Company and your own assessment of the merits and risks of investing in the Bonds. By purchasing any Bonds, you will be deemed to have acknowledged that:

- **you have reviewed this offering memorandum; and**
- **you have had an opportunity to request any additional information that you need from us.**

We are not providing you with any legal, business, tax or other advice in this offering memorandum. You should consult with your own advisors as needed to assist you in making your investment decision and to advise you as to whether you are legally permitted to purchase the Bonds.

You must comply with all laws and regulations that apply to you in any place in which you buy, offer or sell any Bonds or possess or distribute this offering memorandum. You must also obtain any consents or approvals that you need in order to purchase any Bonds. Neither the Company nor any of the initial purchasers is responsible for your compliance with these legal requirements.

We are offering the Bonds in reliance on exemptions from the registration requirements of the Securities Act. These exemptions apply to offers and sales of securities that do not involve a public sale. The Bonds have not been recommended by any federal, state or foreign securities authorities, including the Securities and Exchange Commission (“SEC”), nor have any such authorities determined that this offering memorandum is accurate or complete. Any representation to the contrary is a criminal offense.

The Bonds are subject to restrictions on resale and transfer as described under “Transfer Restrictions” and “Plan of Distribution” and may not be resold or transferred except as permitted under the Securities Act and the applicable state securities laws pursuant to registration or exemption therefrom. By purchasing Bonds, you will be deemed to have made certain acknowledgments, representations and agreements as described in the “Transfer Restrictions” section of this offering memorandum. You may be required to bear the financial risks of investing in the Bonds for an indefinite period of time.

The laws of certain jurisdictions may restrict the distribution of this offering memorandum and the offer and sale of the Bonds. Persons into whose possession this offering memorandum or any of the Bonds come must inform themselves about, and observe, any such restrictions. None of the Company or its representatives, or any of the initial purchasers or any of their representatives, is making any representation to you regarding the legality of any investment in the Bonds by you under applicable legal investment or similar laws or regulations.

This offering memorandum contains summaries believed to be accurate with respect to certain documents, but reference is made to the actual documents for complete information. All such summaries are qualified in their entirety by such reference. Copies of documents referred to herein (excluding confidential information contained therein, if any) will be made available to you upon request to the Company or the initial purchasers.

AVAILABLE INFORMATION

The Company is not subject to the informational requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act") and therefore does not file periodic reports or other information required thereby with the SEC. We have agreed to make certain information available to holders of the Bonds, as described under "Description of the Bonds — Agreement to Provide Information."

The Company will furnish upon the request of any holder of the Bonds, to such holder and a prospective purchaser designated by such holder, the information required to be delivered under Rule 144A(d)(4) under the Securities Act if at the time of the request the Company is not a reporting company under Section 13 or Section 15(d) of the Exchange Act.

You may obtain such information from us, without charge, by either calling or writing to us at:

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507
Attention: Corporate Secretary
Telephone: (502) 627-2000

NOTICE TO NEW HAMPSHIRE RESIDENTS

NEITHER THE FACT THAT A REGISTRATION STATEMENT OR AN APPLICATION FOR A LICENSE HAS BEEN FILED UNDER CHAPTER 421-B OF THE NEW HAMPSHIRE UNIFORM SECURITIES ACT ("RSA 421-B") WITH THE STATE OF NEW HAMPSHIRE NOR THE FACT THAT A SECURITY IS EFFECTIVELY REGISTERED OR A PERSON IS LICENSED IN THE STATE OF NEW HAMPSHIRE CONSTITUTES A FINDING BY THE SECRETARY OF STATE OF NEW HAMPSHIRE THAT ANY DOCUMENT FILED UNDER RSA 421-B IS TRUE, COMPLETE AND NOT MISLEADING. NEITHER ANY SUCH FACT NOR THE FACT THAT AN EXEMPTION OR EXCEPTION IS AVAILABLE FOR A SECURITY OR A TRANSACTION MEANS THAT THE SECRETARY OF STATE OF NEW HAMPSHIRE HAS PASSED IN ANY WAY UPON THE MERITS OR QUALIFICATIONS OF, OR RECOMMENDED OR GIVEN APPROVAL TO, ANY PERSON, SECURITY OR TRANSACTION. IT IS UNLAWFUL TO MAKE, OR CAUSE TO BE MADE, TO ANY PROSPECTIVE PURCHASER, CUSTOMER OR CLIENT ANY REPRESENTATION INCONSISTENT WITH THE PROVISIONS OF THIS PARAGRAPH.

REGISTRATION RIGHTS; SEC REVIEW

We have agreed to file a registration statement with the SEC with respect to an exchange offer for the Bonds or a shelf registration with respect to resales of the Bonds. See "Registration Rights Agreement." In the course of the review by the SEC of the registration statement, we may be required or we may elect to make changes to the information contained in this offering memorandum, including the description of our business, financial statements and other financial or other information. We believe that the financial data, including pro forma financial data, and other information included in this offering memorandum have been prepared in a manner that complies, in all material respects, with current practice and generally accepted accounting principles in the United States of America ("U.S. GAAP"). However, comments by the SEC on any such registration statement may require modification, deletion or reformulation of the financial data and other information presented in this offering memorandum to comply with the regulations published by the SEC. Any such modification or reformulation may be significant.

A WARNING ABOUT FORWARD-LOOKING STATEMENTS

We use forward-looking statements in this offering memorandum. Statements that are not historical facts are forward-looking statements, and are based on beliefs and assumptions of our management, and on information currently available to management. Forward-looking statements include statements preceded by, followed by or using such words as "believe," "expect," "anticipate," "plan," "estimate" or similar expressions. Such statements speak only as of the date they are made, and we undertake no obligation to update publicly any of them in light of new information or future events. Actual results may materially differ from those implied by forward-looking statements due to known and unknown risks and uncertainties. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- fuel supply availability;
- weather conditions affecting generation production, customer energy use and operating costs;
- operation, availability and operating costs of existing generation facilities;
- transmission and distribution system conditions and operating costs;
- collective labor bargaining negotiations;
- the outcome of litigation against us;
- potential effects of threatened or actual terrorism or war or other hostilities;
- our commitments and liabilities;
- market demand and prices for energy, capacity, transmission services, emission allowances and delivered fuel;
- competition in retail and wholesale power markets;
- liquidity of wholesale power markets;
- defaults by our counterparties under our energy, fuel or other power product contracts;
- market prices of commodity inputs for ongoing capital expenditures;
- capital market conditions, including the availability of capital or credit, changes in interest rates, and decisions regarding capital structure;
- the fair value of debt and equity securities and the impact on defined benefit costs and resultant cash funding requirements for defined benefit plans;
- interest rates and their affect on pension and retiree medical liabilities;
- the impact of the current financial and economic downturn;
- volatility in financial or commodity markets;
- profitability and liquidity, including access to capital markets and credit facilities;
- new accounting requirements or new interpretations or applications of existing requirements;
- securities and credit ratings;
- current and future environmental conditions and requirements and the related costs of compliance, including environmental capital expenditures, emission allowance costs and other expenses;
- political, regulatory or economic conditions in states, regions or countries where we conduct business;
- receipt of necessary governmental permits, approvals and rate relief;
- new state or federal legislation, including new tax, environmental, health care or pension-related legislation;
- state or federal regulatory developments;

- the impact of any state or federal investigations applicable to us and the energy industry;
- the effect of any business or industry restructuring;
- development of new projects, markets and technologies;
- performance of new ventures; and
- asset acquisitions and dispositions.

In light of these risks and uncertainties, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. For additional details regarding these and other risks and uncertainties, see "Risk Factors" on page 7 of this offering memorandum.

SUMMARY

This summary highlights certain information concerning the Company and this offering that may be contained elsewhere in this offering memorandum. This summary is not complete and does not contain all the information that may be important to you. You should read this offering memorandum in its entirety before making an investment decision.

Kentucky Utilities Company

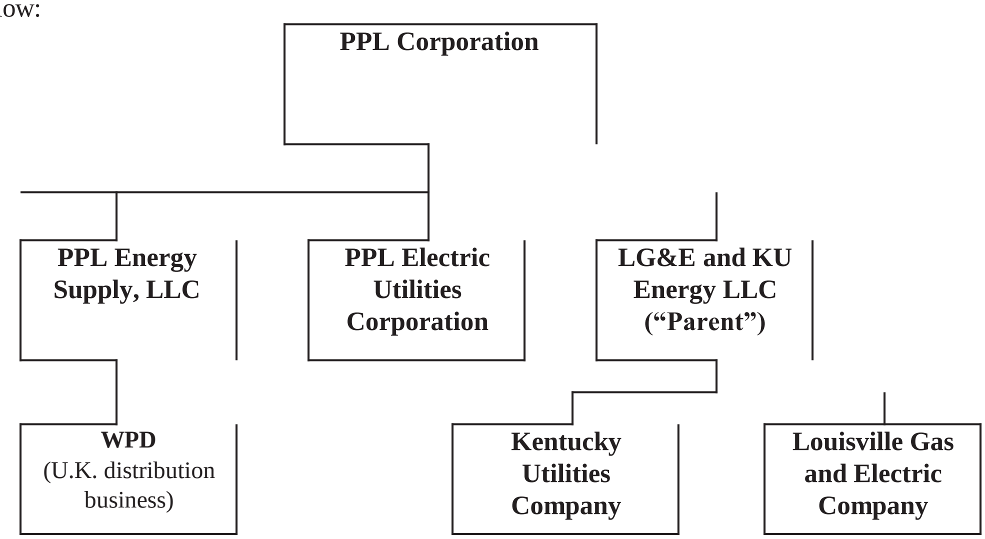
Kentucky Utilities Company (the "Company"), incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. We provide electric service to approximately 515,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 29,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. Our service area covers approximately 6,600 square miles. During the first three quarters of 2010, approximately 99% of the electricity generated by us was produced by our coal-fired electric generating stations. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. In Virginia, we operate under the name Old Dominion Power Company. We also sell wholesale electric energy to 12 municipalities.

Our principal executive offices are located at One Quality Street, Lexington, Kentucky 40507 (Telephone number (502) 627-2000).

Recent Developments

PPL Acquisition

On November 1, 2010, we became an indirect wholly-owned subsidiary of PPL Corporation ("PPL"), when PPL acquired all of the outstanding limited liability company interests in our direct parent, LG&E and KU Energy LLC ("Parent") (formerly E.ON U.S. LLC), from E.ON US Investments Corp. Our Parent, a Kentucky limited liability company, also owns our affiliate, Louisville Gas and Electric Company ("LG&E"), a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and distribution and sale of natural gas in Kentucky. Following the acquisition, our business has not changed, and we and LG&E are continuing as subsidiaries of our Parent, which is now an intermediary holding company in the PPL group of companies. An abridged structure of the PPL group of companies, including our Parent, us and LG&E, is shown below:



PPL, incorporated in 1994 and headquartered in Allentown, Pennsylvania, is an energy and utility holding company. Through its subsidiaries, PPL Corporation owns or controls about 19,000 megawatts of generating capacity in the United States, sells energy in key U.S. markets, and delivers electricity and natural gas to about 5.2 million customers in the United States and the United Kingdom.

Neither PPL nor any of its other subsidiaries, including our Parent or LG&E, will be obligated to make payments on, or provide any credit support for, the Bonds.

Repayment of Fidelia Loan

In connection with the acquisition of our Parent by PPL, we were required to repay loans, in aggregate principal amount of $1.331 billion, from Fidelia Corporation (an affiliate of E.ON AG, a German corporation and the previous indirect parent company of our Parent). We repaid such loans with the proceeds of loans from a PPL subsidiary. We intend to use the proceeds of this offering to repay such loans. See “Use of Proceeds.”

Credit Facility

On November 1, 2010, we entered into a $400 million unsecured Revolving Credit Agreement with a group of banks. Affiliates of the initial purchasers are lenders and/or agents under the new credit facility. Under this new credit facility, which expires on December 31, 2014, we have the ability to make cash borrowings and to request the lenders to issue letters of credit. Borrowings will generally bear interest at LIBOR-based rates plus a spread, depending upon our senior unsecured long-term debt rating. The new credit facility contains a financial covenant requiring our debt to total capitalization to not exceed 70% and other customary covenants. Under certain conditions, we may request that the facility’s capacity be increased by up to $100 million. This new credit facility replaced an existing bilateral line of credit totaling $35 million that was terminated on the effective date of the new facility.

Pollution Control Revenue Bonds

On October 29, 2010, in anticipation of the issuance of the Bonds, and to comply with certain requirements to similarly secure approximately $351 million of previously unsecured pollution control revenue bonds issued by various counties in Kentucky on our behalf, we issued approximately $351 million of first mortgage bonds under the Mortgage (as defined in, and as further described under, “Description of the Bonds”) to the trustees under the revenue bond indentures pursuant to which such pollution control revenue bonds were issued.

Kentucky Rate Case

In January 2010, we filed an application with the Kentucky Public Service Commission (the “Kentucky Commission”) requesting an increase in electric base rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. We requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates were suspended until August 1, 2010. A number of intervenors entered the rate case, including the office of the Attorney General of Kentucky (the “AG”), certain representatives of industrial and low-income groups and other third parties, and submitted filings challenging our requested rate increases, in whole or in part. A hearing was held on June 8, 2010. We and all of the intervenors except the AG agreed to a stipulation providing for an increase in electric base rates of
$98 million annually and filed a request with the Kentucky Commission to approve such settlement. An order in the proceeding was issued in July 2010, approving all the provisions of the stipulation, with rates effective on and after August 1, 2010.

PPL Acquisition Approvals

In September 2010, the Kentucky Commission approved a settlement agreement among PPL and all of the intervening parties to PPL’s joint application to the Kentucky Commission for approval of its acquisition of ownership and control of, our Parent, the Company and LG&E. In the settlement, the parties agreed that we and LG&E would commit that no base rate increases would take effect before January 1, 2013. The Company’s rate increase that took effect on August 1, 2010 (as described above) will not be impacted by the settlement. Under the terms of the settlement, we retain the right to seek approval for the deferral of “extraordinary and uncontrollable costs.” Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management (“DSM”) recovery mechanisms. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Company file a synergies plan with the Kentucky

Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits the Company to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. The settlement agreement contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In October 2010, both the Virginia State Corporation Commission (the "Virginia Commission") and the Tennessee Regulatory Authority approved the transfer of control of the Company from E.ON US Investments Corp. to PPL. Each of these orders contained certain commitments with regard to operations, workforce, community involvement and other matters.

In October 2010, the Federal Energy Regulatory Commission ("FERC") approved a September 2010 settlement agreement among the Company, LG&E, other applicants and protesting parties. The settlement agreement includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain of our municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that we have agreed to not seek the same transaction-related cost from retail customers and agreements to coordinate with protesters in certain open or on-going matters.

Company Strengths

We are a vertically integrated utility company that delivers electricity to approximately 545,000 customers in Kentucky, Virginia and Tennessee. We believe the company operates in a constructive and fair regulatory environment that is generally viewed as balancing the interests of consumers and investors, generally providing timely recovery of approved environmental investments, as well as timely recovery for fuel costs and gas supply. We believe that these regulatory mechanisms, together with periodic rate case filings, provide us the opportunity to earn our allowed return on equity over time. We also have strong customer service records as demonstrated by our J.D. Power regional awards for customer service in seven of the last ten years. We aggressively manage our operating costs and have retail rates that are low compared to other utilities, with 2009 electric retail rates approximately 30% below the Midwest average and 32% below the overall U.S. average, according to the Edison Electric Institute.

We expect to experience significant rate base growth over the next five years. At September 30, 2010, we anticipated that our capital expenditures would total approximately $1.1 billion between 2010 and 2012, resulting in expected rate base growth of approximately $575 million over that period. In addition to this estimate, evolving environmental regulations will likely increase the level of capital expenditures above the amounts currently expected over the next several years. See "Business — Environmental Matters." We expect that a significant portion of the planned capital expenditures would be recovered through the environmental cost recovery mechanism ("ECR"), a mechanism based on Kentucky law that generally provides timely recovery of regulatory approved costs associated with environmental compliance for coal-fired generation, although recovery cannot be assured. This mechanism includes construction work in progress and a return on equity, currently set at 10.63%. See "Business — Rates and Regulation" for a description of ECR and other recovery mechanisms available to the Company.

The Offering

The following is a brief summary of the principal terms of the Bonds and is not intended to be complete. For a more complete description of the Bonds, please refer to "Description of the Bonds" in this offering memorandum.

Issuer	Kentucky Utilities Company, a Kentucky and Virginia corporation.
Securities Offered	$250,000,000 of First Mortgage Bonds, 1.625% Series due 2015 (the "2015 Bonds"). $500,000,000 of First Mortgage Bonds, 3.250% Series due 2020 (the "2020 Bonds") $750,000,000 of First Mortgage Bonds, 5.125% Series due 2040 (the "2040 Bonds").
Maturity Date	The 2015 Bonds will mature on November 1, 2015. The 2020 Bonds will mature on November 1, 2020. The 2040 Bonds will mature on November 1, 2040.
Interest Rate and Payment Dates	The 2015 Bonds will bear interest at the rate of 1.625% per annum, payable semi-annually in arrears on each May 1 and November 1, commencing May 1, 2011. The 2020 Bonds will bear interest at the rate of 3.250% per annum, payable semi-annually in arrears on each May 1 and November 1, commencing May 1, 2011. The 2040 Bonds will bear interest at the rate of 5.125% per annum, payable semi-annually in arrears on each May 1 and November 1, commencing May 1, 2011. Interest will accrue on the Bonds of each series from the date of issuance of such Bonds.
Optional Redemption	We may redeem the Bonds at our option, in whole at any time or in part from time to time, on not less than 30 nor more than 60 days' notice, at the redemption prices described under "Description of the Bonds — Redemption." We may redeem, in whole or in part, Bonds of any or all series.
Ranking	Each series of Bonds will be our senior secured indebtedness and will rank equally in right of payment with our existing and future first mortgage bonds issued under our Mortgage.
Security	Each series of Bonds will be secured, equally and ratably, by the lien of the Mortgage, which constitutes, subject to Permitted Liens and certain exceptions and exclusions, a first mortgage lien on substantially all of our real and tangible personal property located in Kentucky and used in the generation, transmission and distribution of electricity (other than property duly released from the lien of the Mortgage in accordance with the provisions thereof and certain other excepted property, and subject to certain Permitted Liens), as described under "Description of the Bonds — Security; Lien of the Mortgage."
Events of Default	For a discussion of events that will permit acceleration of the payment of the principal of and accrued interest on the Bonds, see "Description of the Bonds — Events of Default."
Further Issuances	Subject to compliance with certain issuance conditions contained in the Mortgage, we may, without the consent of the Holders of a series of the Bonds, increase the principal amount of the series and issue

	additional bonds of such series having the same ranking, interest rate, maturity and other terms (other than the date of issuance and, in some circumstances, the initial interest accrual date and initial interest payment date) as the Bonds. Any such additional bonds would, together with the existing Bonds of such series, constitute a single series of securities under the Mortgage and may be treated as a single class for all purposes under the Mortgage, including, without limita- tion, voting, waivers and amendments.
Company Obligations	Our obligations to pay the principal of, premium, if any, and interest on the Bonds are solely obligations of the Company and none of our direct or indirect parent companies nor any of their subsidiaries or affiliates will guarantee or provide any credit support for our obliga- tions on the Bonds.
Denominations	Minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.
Form of Bonds	The Bonds will be issued in fully registered book-entry form and each series of Bonds will be represented by one or more global certificates, which will be deposited with or on behalf of DTC and registered in the name of DTC's nominee. Beneficial interests in global certificates will be shown on, and transfers thereof will be effected only through, records maintained by DTC and its direct and indirect participants, and your interest in any global certificate may not be exchanged for certificated bonds, except in limited circumstances described herein. See "Description of the Bonds — Book-Entry Only Issuance — The Depository Trust Company."
Trustee	The Bank of New York Mellon
Exchange Offer; Registration Rights . . .	Under a registration rights agreement to be executed as part of this offering, we will agree to: • file a registration statement with the SEC within 180 days after the date the Bonds are issued with respect to a registered offer to exchange the Bonds for substantially identical Bonds that have been registered under the Securities Act and use commercially reasonable efforts to cause such registration statement to be declared effective by the SEC within 270 days after the date the Bonds are issued; and • commence the exchange offer promptly after the registration state- ment is declared effective by the SEC. In certain circumstances, we may also be required to file a shelf registration statement to cover resales of the Bonds. We will also agree to pay liquidated damages on the Bonds if we do not meet certain of our obligations under the registration rights agreement. See "Regis- tration Rights Agreement."
Transfer Restrictions	The Bonds have not been registered under the Securities Act or the securities laws of any jurisdiction. The Bonds are subject to certain restrictions on transfer and may only be offered or sold in transactions exempt from, or not subject to, the registration requirements of the Securities Act and applicable state securities laws. See "Transfer Restrictions."

Absence of Established Market for the Bonds	We do not plan to have the Bonds listed on any securities exchange or included in any automated quotation system There is no existing trading market for the Bonds, and there can be no assurance regarding any future development of a trading market for the Bonds, the price at which holders of the Bonds may be able to sell their Bonds or the ability of such holders to sell their Bonds at all. The initial purchasers have advised us that they currently intend to make a market for the Bonds. However, they are not obligated to do so and may discontinue any market-making with respect to the Bonds at any time without notice in their sole discretion. Accordingly, we cannot assure you of the development or liquidity of any market for the Bonds.
Use of Proceeds	In connection with the PPL acquisition of our Parent on November 1, 2010, we borrowed funds from a PPL subsidiary, in order to repay loans from a subsidiary of E.ON AG. We plan to use the net proceeds received by us from the sale of the Bonds to repay the debt owed to the PPL subsidiary arising from that borrowing, and to use the remaining amount for general corporate purposes. See "Use of Proceeds."
Certain U.S. Federal Income Tax Consequences	You should carefully read the information under the heading "Material U.S. Federal Income Tax Consequences."
Risk Factors	You should refer to the section entitled "Risk Factors" beginning on page 7 for a discussion of material risks you should carefully consider before deciding to invest in the Bonds.

RISK FACTORS

An investment in the Bonds involves a number of risks. Risks described below should be carefully considered together with the other information included in this offering memorandum. Any of the events or circumstances described as risks below could result in a significant or material adverse effect on our business, results of operations, cash flows or financial condition, and a corresponding decline in the market price of, or our ability to repay, the Bonds. The risks and uncertainties described below may not be the only risks and uncertainties that we face. Additional risks and uncertainties not currently known or that we currently deem immaterial may also result in a significant or material adverse effect on our business, results of operations, cash flow or financial condition.

Risks related to the Company

Our business is subject to significant and complex governmental regulation.

Various federal and state entities, including but not limited to the FERC, the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority, regulate many aspects of our utility operations, including:

- the rates that we may charge and the terms and conditions of our service and operations;
- financial and capital structure matters;
- siting and construction of facilities;
- mandatory reliability and safety standards, and other standards of conduct;
- accounting, depreciation, and cost allocation methodologies;
- tax matters;
- affiliate restrictions;
- acquisition and disposal of utility assets and securities; and
- various other matters.

Such regulations or changes thereto may subject us to higher operating costs or increased capital expenditures and failure to comply could result in sanctions or possible penalties. In any rate-setting proceedings, federal or state agencies, intervenors and other permitted parties may challenge our rate requests and ultimately reduce, alter or limit the rates we seek.

Our profitability is highly dependent on our ability to recover the costs of providing energy and utility services to our customers and earn an adequate return on our capital investments. We currently provide services to our retail customers at rates approved by one or more federal or state regulatory commissions, including those commissions referred to above. While these rates are generally regulated based on an analysis of our costs incurred in a base year, the rates we are allowed to charge may or may not match our costs at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commissions will consider all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs or an adequate return on our capital investments. If our costs are not adequately recovered through rates, it could have an adverse affect on our business, results of operations, cash flows or financial condition.

We have agreed, subject to certain limited exceptions such as fuel and environmental cost recoveries, that no base rate increase would take effect for our Kentucky retail customers before January 1, 2013. See “Summary — Recent Developments — PPL Acquisition Approvals.”

Transmission and interstate market activities of the Company, as well as other aspects of the business, are subject to significant FERC regulation.

Our business is subject to extensive regulation by the FERC covering matters including rates charged to transmission users, market-based or cost-based rates applicable to wholesale customers; interstate power market structure; construction and operation of transmission facilities; mandatory reliability standards; standards of conduct and affiliate restrictions and other matters. Existing FERC regulation, changes thereto or issuances of new rules or situations of non-compliance, including but not limited to the areas of market-based tariff authority, Revenue Sufficiency Guarantee (“RSG”) resettlements in the Midwest Independent Transmission System Operator, Inc. market, mandatory reliability standards and natural gas transportation regulation can affect the earnings, operations or other activities of the Company.

Changes in transmission and wholesale power market structures could increase costs or reduce revenues.

Wholesale revenues fluctuate with regional demand, fuel prices and contracted capacity. Changes to trans- mission and wholesale power market structures and prices may occur in the future, are not estimable and may result in unforeseen effects on energy purchases and sales, transmission and related costs or revenues. These can include commercial or regulatory changes affecting power pools, exchanges or markets in which we participate.

We undertake significant capital projects and these activities are subject to unforeseen costs, delays or failures, as well as risk of inadequate recovery of resulting costs.

Our business is capital intensive and requires significant investments in energy generation and distribution and other infrastructure projects, such as projects for environmental compliance. The completion of these projects without delays or cost overruns is subject to risks in many areas, including:

- approval, licensing and permitting;
- land acquisition and the availability of suitable land;
- skilled labor or equipment shortages;
- construction problems or delays, including disputes with third party intervenors;
- increases in commodity prices or labor rates;
- contractor performance;
- environmental considerations and regulations;
- weather and geological issues; and
- political, labor and regulatory developments.

Failure to complete our capital projects on schedule or on budget, or at all, could adversely affect our financial performance, operations and future growth.

Our costs of compliance with, and liabilities under, environmental laws are significant and are subject to continuing changes.

Extensive federal, state and local environmental laws and regulations are applicable to our air emissions, water discharges and the management of hazardous and solid waste, among other areas; and the costs of compliance or alleged non-compliance cannot be predicted with certainty but could be material. In addition, our costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of our key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for our services

Our operating results are affected by weather conditions, including storms and seasonal temperature variations, as well as by significant man-made or accidental disturbances, including terrorism or natural disasters.

These weather or other factors can significantly affect our finances or operations by changing demand levels; causing outages; damaging infrastructure or requiring significant repair costs; affecting capital markets and general economic conditions or impacting future growth.

We are subject to operational and financial risks regarding potential developments concerning global climate change.

Various regulatory and industry initiatives have been implemented or are under development to regulate or otherwise reduce emissions of greenhouse gases ("GHGs"), which are emitted from the combustion of fossil fuels such as coal and natural gas, as occurs at our generating stations. Such developments could include potential federal or state legislation or industry initiatives allocating or limiting GHG emissions; establishing costs or charges on GHG emissions or on fuels relating to such emissions; requiring GHG capture and sequestration; establishing renewable portfolio standards or generation fleet-diversification requirements to address GHG emissions; pro- moting energy efficiency and conservation; changes in transmission grid construction, operation or pricing to accommodate GHG-related initiatives; or other measures. Our generation fleet is predominantly coal-fired and may be highly impacted by developments in this area. Compliance with any new laws or regulations regarding the reduction of GHG emissions could result in significant changes to the Company's operations, significant capital expenditures by the Company and a significant increase in our cost of conducting business. We may face strong competition for, or difficulty in obtaining, required GHG-compliance related goods and services, including construction services, emissions allowances and financing, insurance and other inputs relating thereto. Increases in our costs or prices of producing or selling electric power due to GHG-related developments could materially reduce or otherwise affect the demand, revenue or margin levels applicable to our power, thus adversely affecting our financial condition or results of operations.

We are subject to physical, market and economic risks relating to potential effects of climate change.

Climate change may produce changes in weather or other environmental conditions, including temperature or precipitation changes, such as warming or drought. These changes may affect farm and agriculturally-dependent businesses and activities, which are an important part of Kentucky's economy, and thus may impact consumer demand for electric power. Temperature increases could result in increased overall electricity volumes or peaks and precipitation changes could result in altered availability of water for plant cooling operations. These or other meteorological changes could lead to increased operating costs, capital expenses or power purchase costs by the Company. Conversely, climate change could have a number of potential impacts tending to reduce demand. Changes may entail more frequent or more intense storm activity, which, if severe, could temporarily disrupt regional economic conditions and adversely affect electricity demand levels. As discussed in other risk factors, storm outages and damage often directly decrease revenues or increase expenses, due to reduced usage and higher restoration charges, respectively. GHG regulation could increase the cost of electric power, particularly power generated by fossil-fuels, and such increases could have a depressive effect on the regional economy. Reduced economic and consumer activity in our service area both generally and specific to certain industries and consumers accustomed to previously low-cost power, could reduce demand for our electricity. Also, demand for our services could be similarly lowered should consumers' preferences or market factors move toward favoring energy efficiency, low-carbon power sources or reduced electric usage generally.

Our business is subject to risks associated with local, national and worldwide economic conditions.

The consequences of prolonged recessionary conditions may include a lower level of economic activity and uncertainty or volatility regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, unfavorable changes in energy and commodity prices and slower customer growth, which may adversely affect our future revenues and growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and our ability to raise capital. A deterioration of economic conditions may lead to decreased production by our industrial customers and, therefore, lower consumption of electricity. Decreased economic activity may also lead to fewer commercial and industrial customers and increased unemployment, which may in turn impact residential customers' ability to pay. Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure. Changes in global demand may impact the ability to acquire sufficient supplies and the cost of those commodities may be higher than expected.

Our business is concentrated in the Midwest United States, specifically Kentucky.

Although we also operate in Virginia and Tennessee, the majority of our operations are concentrated in Kentucky. Local and regional economic conditions, such as population growth, industrial growth, expansion and economic development or employment levels, as well as the operational or financial performance of major industries or customers, can affect the demand for energy and our results of operations. Significant industries and activities in our service territory include automotive; aluminum and steel smelting and fabrication; chemical processing; coal, mineral and ceramic-related activities; educational institutions; health care facilities; paper and pulp processing and water utilities. Any significant downturn in these industries or activities or in local and regional economic conditions in our service area may adversely affect the demand for electricity in our service territory.

We are subject to operational risks relating to our generating plants, transmission facilities, distribution equipment, information technology systems and other assets and activities.

Operation of power plants, transmission and distribution facilities, information technology systems and other assets and activities subjects the Company to many risks, including the breakdown or failure of equipment; accidents; security breaches, viruses or outages affecting information technology systems; labor disputes; obso- lescence; delivery/transportation problems and disruptions of fuel supply and performance below expected levels. Occurrences of these events may impact our ability to conduct our business efficiently or lead to increased costs, expenses or losses.

Although we maintain customary insurance coverage for certain of these risks in common with some other utilities, we do not have insurance covering our transmission and distribution system, other than substations, because we have found the cost of such insurance to be prohibitive. If we are unable to recover the costs incurred in restoring our transmission and distribution properties following damage as a result of tornados or other natural disasters or to recover the costs of other liabilities arising from the risks of our business, through a change in our rates or otherwise, or if such recovery is not received on a timely basis, we may not be able to restore losses or damages to our properties without an adverse effect on our financial condition, results of operations or our reputation.

We are subject to liability risks relating to our generating, transmission, distribution and retail businesses.

Conduct of our physical and commercial operations subjects us to many risks, including risks of potential physical injury, property damage or other financial affects, caused to or caused by employees, customers, contractors, vendors, contractual or financial counterparties and other third-parties.

We could be negatively affected by rising interest rates, downgrades to our bond credit ratings or other negative developments in our ability to access capital markets.

In the ordinary course of business, we are reliant upon adequate long-term and short-term financing means to fund our significant capital expenditures, debt interest or maturities and operating needs. As a capital-intensive business, we are sensitive to developments in interest rate levels; credit rating considerations; insurance, security or collateral requirements; market liquidity and credit availability and refinancing steps necessary or advisable to respond to credit market changes. Changes in these conditions could result in increased costs and decreased liquidity to the Company.

We are subject to commodity price risk, credit risk, counterparty risk and other risks associated with the energy business.

General market or pricing developments or failures by counterparties to perform their obligations relating to energy, fuels, other commodities, goods, services or payments could result in potential increased costs to the Company.

We are subject to risks associated with defined benefit retirement plans, health care plans, wages and other employee-related matters.

We sponsor pension and postretirement benefit plans for our employees. Risks with respect to these plans include adverse developments in legislation or regulation, future costs or funding levels, returns on investments, market fluctuations, interest rates and actuarial matters. Changes in health care rules, market practices or cost structures can affect our current or future funding requirements or liabilities. Without sustained growth in our investments over time to increase the value of our plan assets, we could be required to fund our plans with significant amounts of cash. We are also subject to risks related to changing wage levels, whether related to collective bargaining agreements or employment market conditions, ability to attract and retain key personnel and changing costs of providing health care benefits.

We are subject to risks associated with federal and state tax regulations.

Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact our results of operations. We are required to make judgments in order to estimate our obligations to taxing authorities. These tax obligations include income, property, sales and use and employment-related taxes. We also estimate our ability to utilize tax benefits and tax credits. Due to the revenue needs of the states and jurisdictions in which we operate, various tax and fee increases may be proposed or considered. We cannot predict whether legislation or regulation will be introduced or the effect on the Company of any such changes. If enacted, any changes could increase tax expense and could have a negative impact on our results of operations and cash flows.

Risks Related to the Bonds

If no trading market develops for the Bonds, you may not be able to resell your Bonds at their fair market value or at all.

Each series of Bonds is a new issue of securities with no established trading market and we do not intend to apply for listing of the Bonds on any securities exchange. If no active trading market develops, you may not be able to resell your Bonds at their fair market value or at all. Future trading prices of the Bonds will depend on many factors including, among other things, prevailing interest rates, our operating results and the market for similar securities. No assurance can be given as to the liquidity of or trading market for the Bonds. Accordingly, your ability to sell the Bonds that you purchase or the price at which you will be able to sell the Bonds may be limited.

If the ratings of the Bonds are lowered or withdrawn, the market value of the Bonds could decrease.

A rating is not a recommendation to purchase, hold or sell the Bonds, inasmuch as the rating does not comment as to market price or suitability for a particular investor. The ratings of the Bonds address the rating agencies' views as to the likelihood of the timely payment of interest and the ultimate repayment of principal of the Bonds pursuant to their respective terms. There is no assurance that a rating will remain for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if in their judgment circumstances in the future so warrant. In the event that any of the ratings initially assigned to the Bonds is subsequently lowered or withdrawn for any reason, the market price of the Bonds may be adversely affected.

USE OF PROCEEDS

In connection with the PPL acquisition, on November 1, 2010, we borrowed funds from a PPL subsidiary, in order to repay loans from a subsidiary of E.ON AG. We plan to use the net proceeds received by us from the sale of the Bonds to repay the debt owed to the PPL subsidiary arising from that borrowing.

The intercompany debt being repaid, the terms of which match loans from a subsidiary of E.ON AG repaid at the acquisition closing, totals $1.331 billion and is comprised of 21 loans with maturity dates ranging from 2010 to 2037. Each of the loans bears interest at a fixed rate, and the weighted average interest rate on all loans is 5.50%. Net proceeds in excess of the intercompany debt balance will be used for general corporate purposes.

CAPITALIZATION

The following table sets forth our historical unaudited cash and cash equivalents and capitalization as of September 30, 2010 on an actual basis, and on an as adjusted basis to give effect to the PPL acquisition and associated fair value purchase accounting adjustments and the sale of the Bonds, and the expected application of the net proceeds therefrom.

You should read the data set forth below in conjunction with "Use of Proceeds," "Selected Financial Data," "Management's Discussion and Analysis," "Pro Forma Condensed Financial Information" and our audited and unaudited financial statements and related notes included elsewhere in this offering memorandum.

	As of September 30, 2010	
	Actual	As Adjusted(4)(5)
	(Unaudited) (In millions)	
Cash and cash equivalents	$ 2	$ 142
Long-term debt and notes payable(1):		
Due to unaffiliated parties — including current portion(2)	351	352
Due to affiliates — including current portion	1,331	—
Notes Payable to Affiliates(3)	61	61
Bonds offered hereby		1,500
Total long-term debt and notes payable	$1,743	$1,913
Total equity	2,029	2,643
Total capitalization	$3,772	$4,556

(1) Does not reflect our $400 million unsecured revolving credit facility dated November 1, 2010 (See "Summary — Recent Developments — Credit Facility"). As of November 8, 2010, we had no borrowings outstanding thereunder.

(2) Reflects pollution control bonds issued by various counties in Kentucky on our behalf. See Note 7 to our Financial Statements as of December 31, 2009 and 2008 and for the Years Ended December 31, 2009, 2008 and 2007 (the "2009 Annual Financial Statements") and Note 8 to our Condensed Financial Statements as of September 30, 2010 and December 31, 2009 and for the Three and Nine Months Ended September 30, 2010 and 2009 (the "Third Quarter Financial Statements").

(3) Represents notes payable to our Parent.

(4) Reflects fair value adjustments and the goodwill that has been pushed down from our Parent's financial statements to us as a result of the acquisition by PPL.

(5) Adjustments assume net proceeds based on the principal amount of the Bonds.

PRO FORMA CONDENSED FINANCIAL INFORMATION (UNAUDITED)

On November 1, 2010, PPL completed the purchase of all of the outstanding limited liability company interests of our Parent, for cash consideration of $2,467 million. In addition, PPL assumed, through consolidation, $764 million of outstanding debt, net of $163 million repurchased and held for reissuance, and repaid all indebtedness owed by our Parent and its subsidiaries to subsidiaries of E.ON AG.

The Unaudited Pro Forma Condensed Financial Statements ("pro forma financial statements") have been derived from our historical financial statements.

The historical financial information has been adjusted in the pro forma financial statements to give effect to pro forma events that are: (1) directly attributable to the acquisition; (2) factually supportable; and (3) with respect to the statement of operations, expected to have a continuing impact on our results. Specifically, such pro forma adjustments include:

- Repayment of intercompany debt by us to E.ON AG and its affiliates, initially by intercompany loans from a PPL Subsidiary;
- Adjustments to push down the new basis of accounting recorded by PPL on the post-acquisition balance sheet of the Company; and
- The subsequent issuance of the Bonds assuming proceeds equal to the principal amounts thereof and the use of such proceeds thereafter.

The Unaudited Pro Forma Condensed Statements of Operations ("pro forma statements of operations") for the nine months ended September 30, 2010 and for the year ended December 31, 2009 give effect to the adjustments as if they were completed on January 1, 2009. The Unaudited Pro Forma Condensed Balance Sheet ("pro forma balance sheet") as of September 30, 2010 gives effect to the adjustments as if they were completed on September 30, 2010.

Assumptions and estimates underlying the pro forma adjustments are described in the accompanying notes, which should be read in conjunction with the pro forma financial statements. Generally accepted accounting principles in the United States permit up to one year from the date of acquisition to finalize all purchase accounting adjustments, therefore, the final amounts recorded as of the date of the acquisition may differ materially from the information presented in these pro forma financial statements. These estimates are subject to change pending further review of the assets acquired and liabilities assumed.

The pro forma financial statements have been presented for illustrative purposes only and are not necessarily indicative of results of operations and financial position that would have been achieved had the pro forma events taken place on the dates indicated, or the future results of operations or financial position of the company.

The following pro forma financial statements should be read in conjunction with:

- the accompanying notes to the pro forma financial statements;
- the 2009 Annual Financial Statements and the Third Quarter Financial Statements, contained elsewhere in this offering memorandum.

Pro Forma Condensed Statement of Operations

	Nine Months Ended September 30, 2010		
	Actual	Adjustments	Pro Forma
		(Unaudited) (Millions of dollars)	
Operating Revenues	$1,146		**$1,146**
Operating Expenses			
Fuel for electric generation	391		**391**
Power purchased	135		**135**
Other operation and maintenance	251		**251**
Depreciation, accretion, and amortization	106		**106**
Total Operating Expenses	883		**883**
Operating Income	263		**263**
Other income, net	2		**2**
Interest Expense	5	$ 44(a)	**49**
Interest Expense — Affiliates	55	(55)(a)	**—**
Income from Continuing Operations Before Income Taxes	205	11	**216**
Income Taxes	76	4(b)	**80**
Income from Continuing Operations After Income Taxes	129	7	**136**

The accompanying Notes to Pro Forma Condensed Financial Statements are an integral part of these pro forma financial statements. See Note 3 for information on pro forma adjustment references.

Pro Forma Condensed Statement of Operations

	Year Ended December 31, 2009		
	Actual	Adjustments	Pro Forma
		(Unaudited) (Millions of dollars)	
Operating Revenues	$1,355		**$1,355**
Operating Expenses			
Fuel for electric generation	434		**434**
Power purchased	199		**199**
Other operation and maintenance	320		**320**
Depreciation, accretion, and amortization	133	—	**133**
Total Operating Expenses	1,086	—	**1,086**
Operating Income	269		**269**
Other income, net	6		**6**
Interest Expense	6	59(a)	**65**
Interest Expense — Affiliates	69	(69)(a)	**—**
Income from Continuing Operations Before Income Taxes	200	10	**210**
Income Taxes	67	4(b)	**71**
Income from Continuing Operations After Income Taxes	133	6	**139**

The accompanying Notes to Pro Forma Condensed Financial Statements are an integral part of these pro forma financial statements. See Note 3 for information on pro forma adjustment references.

Pro Forma Condensed Balance Sheet

	September 30, 2010		
	Actual	Adjustments	Pro Forma Entity
		(Unaudited) (Millions of dollars)	
Current Assets			
Cash and cash equivalents	$ 2	$ 140(c)	**$ 142**
Accounts receivable	200		**200**
Fuel, materials and supplies	140		**140**
Regulatory assets	14		**14**
Prepayments and other current assets	11		**11**
Total Current Assets	367	140	**507**
Investment in unconsolidated venture	12	68(d)	**80**
Property, Plant and Equipment, net	4,470	30(l)	**4,500**
Deferred debits and other assets			
Regulatory assets	215	(16)(e)	**199**
Goodwill	—	573(f)	**573**
Other intangibles	—	201(g)	**201**
Other noncurrent assets	46	11(h)	**57**
Total deferred debits and other assets	261	769	**1,030**
Total Assets	5,110	1,007	**6,117**

The accompanying Notes to Pro Forma Condensed Financial Statements are an integral part of these pro forma financial statements. See Note 3 for information on pro forma adjustment references.

Pro Forma Condensed Balance Sheet

	September 30, 2010		
	Actual	Adjustments	Pro Forma Entity
		(Unaudited) (Millions of dollars)	
Liabilities and Equity			
Current Liabilities			
Current portion long-term debt	$ 228		**228**
Current potion long-term debt — affiliated company	33	$ (33)(j)	**—**
Note payable — affiliate	61		**61**
Accounts payable	176	(18)(i)	**158**
Regulatory liabilities	12		**12**
Other current liabilities	62		**62**
Total Current Liabilities	572	(51)	**521**
Long-term Debt	123	1,501(j)	**1,624**
Long-term Debt — Affiliates	1,298	(1,298)(j)	**—**
Deferred Credits and Other Liabilities			
Deferred income taxes and investment tax credit	482	27(p)	**509**
Accumulated provision for pensions and related benefits	160	—(k)	**160**
Asset retirement obligations	59	(4)(l)	**55**
Regulatory liabilities	367	201(m)	**568**
Other liabilities	20	17(n)	**37**
Total Deferred Credits and Other Liabilities	1,088	241	**1,329**
Commitments and Contingent Liabilities			
Total Equity	2,029	614(o)	**2,643**
Total Liabilities and Equity	$5,110	$ 1,007	**$6,117**

The accompanying Notes to Pro Forma Condensed Financial Statements are an integral part of these pro forma financial statements. See Note 3 for information on pro forma adjustment references.

NOTES TO PRO FORMA CONDENSED FINANCIAL STATEMENTS
(Unaudited)

Note 1 — Basis of Pro Forma Presentation

The pro forma statements of operations for the nine months ended September 30, 2010 and for the year ended December 31, 2009 give effect to the adjustments as if they were completed on January 1, 2009. The pro forma balance sheet as of September 30, 2010 gives effect to the adjustments as if they were completed on September 30, 2010.

The pro forma financial statements have been derived from our historical financial statements. Assumptions and estimates underlying the pro forma adjustments are described in the accompanying notes, which should be read in conjunction with the pro forma financial statements. Since the pro forma financial statements have been prepared based upon preliminary estimates, the final amounts recorded at the date of the acquisition may differ materially from the information presented. These estimates are subject to change pending further review of the assets acquired and liabilities assumed.

The pro forma financial statements reflect the push down of the new basis of accounting for our assets and liabilities arising from the acquisition by PPL being accounted for based on the guidance provided by accounting standards for business combinations. In accordance with this accounting guidance, the assets acquired and the liabilities assumed have been measured at fair value by PPL and the difference between these assets and liabilities and the purchase price has been recorded as goodwill (this process is generally referred to as a *purchase price allocation*). In accordance with SEC guidance for wholly-owned subsidiaries, these fair value measurements and an allocated portion of goodwill have been pushed down and recorded on our pro forma financial statements as presented in Note 2. The fair value measurements utilize estimates based on key assumptions of the acquisition, and historical and current market data. These fair value measurements and the related pro forma adjustments included herein may be revised as additional information becomes available and as additional analyses are performed. The final purchase price allocation may differ materially from the information presented. As noted above, the pro forma financial statements also include adjustments to reflect the issuance of the Bonds, with proceeds assumed to equal the principal amount thereof and used to repay indebtedness owed by us to a PPL subsidiary. The indebtedness was incurred to repay loans from a subsidiary of E.ON AG in connection with the PPL acquisition. The preliminary result of all these adjustments is presented in Note 2.

The amounts utilized in determining the pro forma adjustments presented on the Proforma Condensed Financial Statements are also set forth and described in Note 3.

For the purpose of measuring the estimated fair value of the assets acquired and liabilities assumed, PPL has applied the accounting guidance for fair value measurements. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

For purposes of measuring the fair value of the majority of property, plant and equipment and regulatory assets acquired and regulatory liabilities assumed, as reflected in the pro forma financial statements, PPL has determined that the fair value equaled their net book value, due to the regulatory environment in which they operate. The regulatory commissions allow for earning a rate of return on the book values of the regulated asset bases at rates determined to be fair and reasonable. Since there is no current prospect for deregulation, the expectation is that these operations will remain in a regulated environment for the foreseeable future and this presentation represents the highest and best use of these assets. In addition, certain fair value adjustments have been reflected on the balance sheet with an offsetting regulatory asset or liability based upon agreement with the regulatory commissions that purchase accounting adjustments will not impact customers and, therefore, will not be included in any cost recovery mechanisms or rates on a prospective basis..

Note 2 — Preliminary Push Down of Purchase Price Allocation and Replacement of Debt

Preliminary Purchase Price Allocation

The preliminary allocation of the purchase price to the fair value of assets acquired and liabilities assumed includes pro forma adjustments primarily related to the fair value of equity investments, contractual arrangements, goodwill, noncurrent liabilities, long-term debt and related deferred income taxes. The preliminary allocation of the purchase price, including the replacement of debt, is as follows (in millions):

Current assets	$ 507
Property, plant and equipment	4,500
Investments	80
Goodwill	573
Other intangibles	201
Regulatory assets and other noncurrent assets	256
Current liabilities	(521)
Noncurrent liabilities	(1,329)
Long-term debt	(1,624)
Total Equity	$ 2,643

Note 3 — Pro Forma Adjustments

The adjustments included in the pro forma financial statements are as follows:

Adjustments to Pro Forma Condensed Statements of Operations

(a) Interest expense — Reflects the change in interest expense from the extinguishment of indebtedness owed by us to a subsidiary of E.ON AG, and replacement with the Bonds and the application of proceeds thereof. The interest expense was adjusted assuming a weighted-average interest rate of 3.9%. No adjustment has been made for the actual rates.

(b) Income taxes — Reflects the income tax effect of the pro forma adjustments, which was calculated using an estimated statutory income tax rate of 40%. Income tax expense includes adjustments for state taxes and certain federal income tax items that are calculated on a combined or consolidated basis.

Adjustments to Pro Forma Condensed Balance Sheet

(c) Cash — Reflects $1,500 million of estimated proceeds from the Bonds. This amount was offset by a $1,331 million of estimated repayment of the indebtedness and payables owed to subsidiaries of E.ON AG and its affiliates, the repayment of $18 million of affiliate accounts payable, and approximately $11 million related to the payment of debt issuance costs.

(d) Investments — Reflects the fair value adjustment of $68 million related to our equity method investment in Electric Energy, Inc.

(e) Regulatory assets — Reflects the offsetting regulatory asset related to the fair value adjustments associated with the fair value of debt, coal contracts and asset retirement obligations. These fair value adjustments have been reflected on the balance sheet with an offsetting regulatory asset based upon agreement with the regulatory commissions that purchase accounting adjustments will not impact customers and, therefore, will not be included in any cost recovery mechanisms or rates on a prospective basis.

(f) Goodwill — Reflects the preliminary estimate of the excess of the purchase price paid over the net fair value of our assets acquired and liabilities assumed. This excess is calculated as follows (in millions):

Purchase price	$2,643
Less: Fair value of net assets acquired	2,070
Estimated goodwill resulting from the acquisition	573
Less: pre-existing goodwill	—
Pro forma goodwill adjustment	$ 573

PPL has not yet completed its goodwill allocation evaluation, but will allocate the final amount of goodwill to its reporting units that are expected to benefit from the business combination in accordance with applicable accounting guidance. The resulting goodwill that will ultimately be allocated and pushed down to us could differ materially from the amount presented.

(g) Other intangibles — Reflects the recognition of $188 million related to the fair value of certain coal contracts and $13 million related the fair value of emission allowances.

(h) Other noncurrent assets — Reflects the capitalization of $11 million of estimated debt issuance costs incurred with the issuance of the Bonds.

(i) Accounts payable — Reflects the payment of affiliate accounts payable to E.ON AG and its affiliates.

(j) Debt — Reflects the adjustments to repay $1,331 million of indebtedness owed by us to a subsidiary of E.ON AG and its affiliates. This decrease is offset by the issuance of $1,500 million of the Bonds at an assumed weighted-average interest rate of 3.9%. No adjustment has been made for the actual rates. In addition, an increase of
$1 million was recorded to reflect the fair value of the assumed debt. The ultimate fair value determination of the debt will be based on prevailing market interest rates at the completion of the acquisition and the adjustment will be amortized as an adjustment to interest expense over the remaining life of the debt issues.

(k) Accumulated provision for pensions and related benefits — The accrued pension obligations have not been adjusted as the information required to make such adjustment was not yet available. The resulting adjustment could differ materially from the amount presented.

(l) Asset retirement obligations — Reflects a $4 million adjustment to record the fair value of asset retirement obligations. As a result, the associated regulatory assets of $34 million were written off, and $30 million related to property, plant and equipment, net, were recorded.

(m) Regulatory liabilities — Reflects the offsetting regulatory liability related to the fair value adjustments associated with the fair value of emission allowances and coal contracts. These fair value adjustments have been reflected on the balance sheet with an offsetting regulatory liability based upon agreement with the regulatory commissions that purchase accounting adjustments will not impact customers and, therefore, will not be included in any cost recovery mechanisms or rates on a prospective basis.

(n) Other noncurrent liabilities — Reflects the recognition of the fair value of certain coal contracts.

(o) Equity — Reflects the net purchase accounting adjustments to increase our historical equity balance of $2,029 million to recognize the $2,643 million of equity from the purchase price, including the push down of $573 million of goodwill resulting from acquisition and other fair value adjustments previously discussed.

(p) Deferred income taxes — Represents estimated deferred taxes calculated at our estimated statutory tax rate of 40% applied to certain fair value adjustments recorded to the assets acquired and liabilities assumed, excluding goodwill.

SELECTED FINANCIAL DATA

The selected financial data presented below for the years ended December 31, 2006 and 2005 and as of December 31, 2007, 2006 and 2005 have been derived from our audited financial statements and are not included in this offering memorandum. The selected financial data for the years ended December 31, 2009, 2008 and 2007 and as of December 31, 2009 and 2008 have been derived from our audited financial statements and are included in this offering memorandum. The selected financial data for the nine months ended September 30, 2010 and 2009 and as of September 30, 2010 and 2009 are derived from our unaudited financial statements included in this offering memorandum. The unaudited financial statements reflect all adjustments, including only usual recurring adjust- ments, which in the opinion of management, are necessary for the fair representation of that information for and as of the periods presented. Historical results are not necessarily indicative of future results and results for the nine months ended September 30, 2010 are not necessarily indicative of results to be expected for the full year.

You should read the data set forth below in conjunction with "Use of Proceeds," "Management's Discussion and Analysis" and our audited and unaudited financial statements and related notes included elsewhere in this offering memorandum.

	Nine Months Ended September 30,		Year Ended December 31,				
	2010	2009	2009	2008	2007	2006	2005
	(Unaudited)						
				(In millions)			
Income Statement Data:							
Operating revenues	$1,146	$1,009	$1,355	$1,405	$1,272	$1,210	$1,207
Net operating income	$ 263	$ 197	$ 269	$ 260	$ 267	$ 235	$ 202

	As of September 30,		As of December 31,				
	2010	2009	2009	2008	2007	2006	2005
	(Unaudited)						
Balance Sheet Data:							
Total assets	$5,110	$4,830	$4,956	$4,518	$3,796	$3,148	$2,756
Long-term debt	$1,682	$1,632	$1,682	$1,532	$1,264	$ 843	$ 746

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis by management focuses on those factors that had a material effect on our results of operations and financial condition during the periods presented and should be read in connection with the financial statements and notes included elsewhere in this offering memorandum. The discussion contains certain forward-looking statements that involve risk and uncertainties. See "Forward Looking Statements" and "Risk Factors."

Years Ended December 31, 2009, 2008 and 2007

Results of Operations

The electric utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Net Income

Net income in 2009 decreased $25 million compared to 2008. The decrease was primarily the result of decreased operating revenues ($50 million), decreased equity in earnings ($29 million), decreased other income — net ($3 million) and increased interest expense ($3 million), partially offset by decreased operating expenses ($59 million) and decreased income taxes ($1 million).

Net income in 2008 decreased $9 million compared to 2007. The decrease was primarily the result of increased operating expenses ($140 million) and increased interest expense ($16 million), partially offset by increased operating revenues ($133 million), decreased income taxes ($9 million), increased equity in earnings ($4 million) and increased other income — net ($1 million).

Revenues

Revenues in 2009 decreased $50 million compared to 2008 primarily due to:

- Decreased wholesale sales ($75 million) due to lower sales volumes to LG&E ($60 million) and third-parties ($16 million). These lower volumes were primarily due to lower economic demand caused by low spot market pricing during most of 2009, and due to higher scheduled coal-fired generation unit outages during 2009. Via a mutual agreement, we sell our higher cost electricity to LG&E for its wholesale sales and we purchase LG&E's lower cost electricity to serve our native load. These decreases were partially offset by increased prices ($1 million) for sales to LG&E due to the higher cost of fuel inventory.

- Decreased retail sales volumes delivered ($55 million) due to reduced consumption by residential customers as a result of milder weather and significant 2009 storm outages as well as low energy usage by industrial and commercial customers as a result of weakened economic conditions.

- Decreased fuel costs billed to customers through a fuel adjustment clause ($2 million) due to a refund of power purchased costs from Owensboro Municipal Utilities ("OMU") ($6 million), partially offset by increased fuel prices ($4 million).

- Decreased gains in unrealized energy marketing financial swaps ($2 million).

Partially offset by:

- Increased environmental cost recovery surcharge ($50 million) due to increased recoverable capital spending.

- Decreased merger surcredit ($13 million) due to the surcredit termination in February 2009.

- Increased DSM cost recovery ($9 million) due to increased recoverable program spending.

- Increased miscellaneous revenue ($6 million) resulting from the assessment of late payment fees beginning in the second quarter of 2009.

- Increased retail sales revenue from base rates ($5 million) due to the increase in Virginia rates in November 2009, and application of the Kentucky base rate settlement resulting in higher customer charge and demand revenue, partially offset by lower energy revenue.

•Decreased value delivery team (“VDT”) process surcredit ($1 million) due to termination in August 2008.

Revenues in 2008 increased $133 million compared to 2007 primarily due to:

- Increased fuel costs billed to customers through the fuel adjustment clause ($52 million) due to increased fuel prices
- Increased wholesale sales ($48 million) due to higher sales volumes and prices. Volumes increased to LG&E ($34 million) and third-parties ($10 million) as a result of excess generation made available by LG&E via a mutual agreement. We sell our higher cost electricity to LG&E for LG&E to make wholesale sales and we purchase LG&E’s lower cost electricity to serve our native load. Both the Company and LG&E experienced lower native load requirements due to milder weather and the weakening economy, and increased generation due to fewer scheduled coal-fired generation unit outages during 2008, resulting in higher volumes available for wholesale sales. Pricing to third-parties increased as a result of higher fuel costs ($2 million). Wholesale sales also increased due to gains in energy marketing financial swaps ($2 million).
- Increased environmental cost recovery surcharge ($43 million) due to increased recoverable capital spending
- Increased DSM cost recovery ($2 million) due to additional conservation programs
- Increased transmission sales ($2 million) due to higher sales to LG&E
- Decreased merger surcredit ($2 million) due to a lower rate approved by the Kentucky Commission in June 2008

•Decreased VDT surcredit ($1 million) due to its termination in August 2008.

Partially offset by:

- Decreased retail sales volumes delivered ($17 million) due to a 26% decrease in cooling degree days and weakening economic conditions

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the fuel adjustment clause, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC.

Electric Generation Expense

Expenses related to fuel for electric generation decreased $79 million in 2009 compared to 2008 primarily due to:

•Decreased volumes of fuel usage ($97 million) due to decreased native load and wholesale sales

Partially offset by:

- Increased commodity and transportation costs for coal ($18 million)

Expenses related to fuel for electric generation increased $52 million in 2008 compared to 2007 primarily due to:

- Increased commodity and transportation costs for coal and natural gas ($39 million)
- Increased generation ($13 million) due to increased utilization of coal-fired generation units as a result of fewer scheduled outages in 2008

Power Purchased Expense

Power purchased expense decreased $22 million in 2009 compared to 2008 primarily due to:

- Decreased prices for purchases used to serve retail customers ($18 million) due to lower spot market pricing and increased availability of power from OMU
- Decreased purchases from LG&E due to lower prices ($7 million) and lower volumes ($2 million). Via a mutual agreement, we purchase LG&E's lower cost electricity to serve our native load. LG&E provided lower volumes due to its increased scheduled coal-fired outages during the fourth quarter of 2009.
- Decreased power purchased expense ($6 million) due to a refund of power purchased costs related to the OMU settlement.

Partially offset by:

- Increased third-party purchased volumes for native load ($8 million) primarily due to scheduled coal-fired generation unit outages.
- Increased demand payments for third-party purchases ($3 million) on long-term contracts.

Power purchased expense increased $53 million in 2008 compared to 2007 primarily due to:

- Increased prices for purchases used to serve retail customers ($24 million) due to higher market prices, influenced by higher fuel costs
- Increased power purchased from LG&E via a mutual agreement due to higher volumes ($8 million) and higher prices ($8 million). We purchase LG&E's lower cost electricity to serve our native load. LG&E was able to provide higher volumes due to its reduced native load requirements as a result of milder weather and the weakening economy.
- Increased demand payments ($7 million) for energy purchased on a long-term contract
- Increased third-party power purchase volume for native load ($5 million) due to increased unscheduled coal- fired generation unit outages
- Increased expenses ($1 million) due to activities in the PJM Interconnection LLC market for the entire year of 2008 compared to only one quarter in 2007

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $45 million in 2009 compared to 2008 primarily due to increased other operation expenses ($30 million) and increased other maintenance expenses ($15 million).

Other operation expenses increased $30 million in 2009 compared to 2008 primarily due to:

- Increased pension expense ($20 million) due to lower 2008 pension asset investment performance.
- Increased steam expense ($7 million) due to utilization of selective catalytic reductions year-round.
- Increased administrative and general expense ($5 million) due to increased DSM program spending as well as consulting fees for software training and increased labor and benefit costs, partially offset by decreased legal expenses mainly related to OMU in 2008, which case was settled in the second quarter of 2009.

Partially offset by:

- Decreased generation expense ($2 million) due to scheduled unit outages and routine maintenance

Other maintenance expenses increased $15 million in 2009 compared to 2008 primarily due to:

- Increased steam expense ($7 million) due to increased scope of work for scheduled outages.
- Increased distribution expense ($5 million) as a result of increased repairs and higher tree trimming expense in 2009 ($3 million) and higher storm related expense in 2009 ($2 million).

- Increased transmission expense ($2 million) primarily due to increased overhead line maintenance for North American Electric Reliability Corporation ("NERC") mandatory reliability compliance.
- Increased administrative and general expense ($1 million) due to increased labor and system maintenance contracts resulting from completion of a significant in-house customer information system project.

Other operation and maintenance expenses increased $20 million in 2008 compared to 2007 primarily due to increased other operation expenses ($16 million) and increased maintenance expenses ($4 million).

Other operation expenses increased $16 million in 2008 compared to 2007 primarily due to:

- Increased outside services ($4 million) due to increased legal expenses as a result of on-going litigation, mainly with OMU
- Increased cost of consumables ($4 million) due to contract pricing and commissioning and start up costs of flue gas desulfurization systems ("FGDs")
- Increased transmission expense ($2 million) due to increased native load purchases from LG&E and the additional costs to comply with growing SERC Reliability Corporation and NERC Mandatory Reliability Standards
- Increased distribution expense ($2 million) due to storm restoration
- Increased uncollectible accounts ($2 million) due to the weakening economy
- Increased property taxes ($2 million) due to net decrease in expense in 2007 as a result of the application of coal tax credits

Other maintenance expenses increased $4 million in 2008 compared to 2007 primarily due to increased maintenance of overhead conductors and devices ($4 million) resulting from storm restoration.

Income from Equity Investments

Equity income from Electric Energy, Inc. ("EEI"), in which we own 20% of the common stock, decreased $29 million in 2009 compared to 2008 primarily due to lower earnings resulting from decreased market prices.

Equity income in EEI increased $4 million in 2008 primarily due to an increased average price per megawatt hour sold in 2008 over the price for 2007.

Other Income — Net

Other income — net decreased $3 million in 2009 compared to 2008 primarily due to:

- Decreased $2 million due to discontinuance of allowance for funds used during construction on environ- mental cost recovery projects as a result of the FERC rate case.
- Decreased $1 million due mainly to depreciation expense on joint-use assets related to Trimble County Unit 2 ("TC2") transferred from LG&E and currently held for future use.

Other income — net increased $1 million in 2008 compared to 2007, primarily due to:

- Increased $3 million due to allowance for funds used during construction related to several large multi-year projects
- Increased $1 million due to net losses on the sale of property in 2007

Partially offset by:

- Decreased $2 million due to lower income earned on bond deposits for special projects
- Decreased $1 million due to settlement for Brown Station new source review litigation and related programs

Interest Expense

Interest expense increased $3 million in 2009 compared to 2008 primarily due to increased interest expense to affiliated companies ($13 million) resulting from additional debt, partially offset by decreased interest expense ($8 million) due to lower interest rates on bonds and ($2 million) due to lower interest rates on intercompany short term borrowings.

Interest expense increased $16 million in 2008 compared to 2007 primarily due to increased interest expense to affiliated companies ($17 million) due to additional debt, partially offset by decreased interest expense ($1 million) due to interest received on reacquired debt.

Depreciation

Depreciation expense decreased $3 million in 2009 compared to 2008, primarily due to the decrease in depreciation rates that became effective in February 2009, mainly related to an increase in the estimated useful lives on transmission and distribution assets.

Depreciation expense increased $15 million in 2008 compared to 2007, primarily due to an increase in capital assets that were placed in service in 2008.

Income Tax Expense

Components of income tax expense are shown in the table below:

	2009	2008	2007
		(In millions)	
Current — federal	$ (5)	$ 46	$28
— state	1	10	13
Deferred — federal — net	43	(10)	(5)
— state — net	7	(3)	(1)
Investment tax credit — deferred	21	25	43
Amortization of investment tax credit	—	—	(1)
Total income tax expense	$67	$ 68	$77

Deferred federal and state income tax expense increased in 2009 compared to 2008, primarily due to temporary differences related to storm costs and depreciation. The temporary differences also resulted in an offsetting decrease to current federal and state taxes in 2009. Current federal income tax expense increased and investment tax credit — deferred decreased primarily due to claiming $18 million less in investment tax credits in 2008. Current state income tax decreased due to coal credits claimed in 2008. Deferred federal income tax expense decreased in 2008 compared to 2007, primarily due to adjusting prior year estimates to actual based on the filed tax return.

Cash Flows from Operating Activities

Cash provided by operations in 2009 was $39 million less than cash provided by operations in 2008 and was primarily the result of decreases in cash due to changes in:

- Storm restoration expenses ($55 million) deferred for future recovery as regulatory assets
- Accounts receivable ($16 million) due to timing of payments received from the Illinois Municipal Electric Agency (“IMEA”) and the Indiana Municipal Power Agency (“IMPA”) in 2008
- Pension and postretirement funding ($15 million) due to increased contributions made in 2009
- Accounts payable ($12 million) primarily due to fuel purchases and timing of payments
- Prepayment and other current assets ($2 million)

These decreases were partially offset by increases in cash due to changes in:

- Earnings, net of non-cash items ($49 million)[(1)]
- Materials and supplies ($5 million) primarily due to a decrease in cash used for coal inventory
- Other ($7 million)

(1) Management uses the term "earnings, net of non-cash items" in its discussion of cash flows from operating activities to describe net income adjusted by income or expenses not requiring cash currently, including depreciation, accretion, amortization, deferred income taxes, investment tax credits, provision for pension and postretirement benefits and other non-cash items. Although "earnings, net of non-cash items" may not be a measure determined in accordance with accounting principles generally accepted in the United States, the measure facilitates the analysis by management and investors of the Companies' cash flows from operating activities.

Cash provided by operations in 2008 was $19 million less than cash provided by operations in 2007 and was primarily the result of decreases in cash due to changes in:

- Materials and supplies ($55 million) primarily due to increased fuel inventory volumes and higher fuel costs
- Earnings, net of non-cash items ($15 million)[(1)]
- Other ($12 million) primarily due to changes in utility plant and customer advances for construction
- Prepayment and other current assets ($2 million)
- Wind storm regulatory asset ($2 million) due to new regulatory asset for Hurricane Ike restoration expenses

These decreases were partially offset by increases in cash due to changes in:

- Accounts receivable ($28 million) due to timing of payments received from IMEA and IMPA
- Accounts payable ($24 million) primarily due to construction accruals related to FGD projects and TC2
- Pension and postretirement funding ($14 million) due to contributions made in 2007
- Other current liabilities ($1 million)

Cash Flows from Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Net cash used for investing activities decreased $188 million in 2009 compared to 2008 primarily due to decreased capital expen- ditures of $170 million, assets purchased from LG&E of $10 million in 2008 and changes in restricted cash from bonds issued in 2008 used to fund environmental equipment of $8 million. Restricted cash represents the escrowed proceeds of the pollution control bonds, which are disbursed as qualifying costs are incurred.

Net cash used for investing activities decreased $42 million in 2008 compared to 2007 primarily due to decreased capital expenditures of $63 million, partially offset by decreased restricted cash of $11 million and an asset purchased from LG&E of $10 million. Restricted cash represents the escrowed proceeds of the pollution control bonds, which are disbursed as qualifying costs are incurred.

Cash Flows from Financing Activities

Net cash provided by financing activities decreased $151 million due to decreased long-term borrowings from affiliated company of $100 million, lower equity contributions in 2009 of $70 million and reduced issuance of tax- exempt bonds in 2009 totaling $17 million, all of which were partially offset by an increase of short-term borrowing from affiliate of $36 million.

Net cash provided by financing activities decreased $15 million in 2008 compared to 2007, primarily due to decreased long-term borrowings from affiliated company of $198 million, reacquisition of bonds of $80 million, retirement of pollution control bonds of $60 million and issuance of pollution control bonds of $1 million, partially offset by the retirement of first mortgage bonds of $107 million in 2007, increased infusions from our Parent of $70 million, decreased repayment of short-term borrowings from affiliate — net of $67 million, reissuance of reacquired bonds of $63 million and retirement of reacquired bonds of $17 million.

See Note 7 to our 2009 Annual Financial Statements and Note 8 to our Third Quarter Financial Statements, each included elsewhere in this offering memorandum, for information of redemptions, maturities and issuances of long-term debt.

Three Months Ended September 30, 2010, Compared to Three Months Ended September 30, 2009

Results of Operations

Net Income

Net income was $54 million for the three months ended September 30, 2010, compared to $66 million for the same period in 2009. The decrease was primarily the result of the following (In millions of $):

	Three Months Ended September 30,		Increase (Decrease)
	2010	2009	
Total operating revenues	$416	$341	$ 75
Total operating expenses	311	216	95
Operating income	105	125	(20)
Interest expense to affiliated companies	18	18	—
Other income (expense) — net	(1)	(2)	1
Income before income taxes	86	105	(19)
Income tax expense	32	39	(7)
Net income	$ 54	$ 66	$(12)

Revenues

The $75 million increase in operating revenues in the three months ended September 30, 2010, was primarily due to (In millions of $):

	Increase (Decrease)
Retail sales volumes(a)	$40
Retail base rates(b)	14
ECR surcharge due to increased recoverable capital spending	10
Retail fuel adjustment clause (“FAC”) costs billed to customers due to higher fuel prices	6
Other	5
	$75

(a) Primarily due to increased consumption by residential customers as a result of increased cooling degree days and higher energy usage by industrial customers as a result of improved economic conditions and increased cooling degree days.

(b) Primarily due to higher rates effective August 1, 2010. See Note 2 to our Third Quarter Financial Statements, included elsewhere in this offering memorandum, for further discussion of the 2010 Kentucky rate case.

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC. Operating expenses follow (in millions of $):

	Three Months Ended September 30,		
	2010	**2009**	**Increase (Decrease)**
Fuel for electric generation	$146	$114	$32
Power purchased	41	47	(6)
Other operation and maintenance expenses	86	22	64
Depreciation, accretion and amortization	38	33	5
Total operating expenses	$311	$216	$95

Electric Generation Expense

The $32 million increase in fuel for electric generation in the three months ended September 30, 2010, was primarily due to increased volumes of fuel usage due to increased retail sales volumes.

Power Purchased Expense

The $6 million decrease in power purchased expense in the three months ended September 30, 2010, was primarily due to (in millions of $):

	Increase (Decrease)
Third-party purchased volumes for native load	$(8)
Demand payments for third-party purchase	(4)
Prices for purchases used to serve retail customers	6
	$(6)

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $64 million in the three months ended September 30, 2010, due to $55 million of increased maintenance expenses, and $9 million of increased other operation expenses. These increases were primarily due to distribution expenses ($53 million related to maintenance and $4 million related to other operations) incurred in the first quarter of 2009 for wind and ice storm restoration that were reclassified to a regulatory asset in the third quarter of 2009.

Income Tax Expense

See Note 7 to our Third Quarter Financial Statements, included elsewhere in this offering memorandum, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and our income tax expense.

Nine Months Ended September 30, 2010, Compared to Nine Months Ended September 30, 2009

Results of Operations

Net Income

Net income was $129 million for the nine months ended September 30, 2010, compared to $99 million for the same period in 2009. The increase was primarily the result of the following (in millions of $):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase (Decrease)
Total operating revenues	$1,146	$1,009	$137
Total operating expenses	883	812	71
Operating income	263	197	66
Interest expense to affiliated companies	55	51	4
Other income (expense) — net	(3)	2	(5)
Income before income taxes	205	148	57
Income tax expense	76	49	27
Net income	$ 129	$ 99	$ 30

Revenues

The $137 million increase in operating revenues in the nine months ended September 30, 2010, was primarily due to (in millions of $):

	Increase (Decrease)
Retail sales volumes(a)	$ 98
Retail base rates(b)	14
ECR surcharge due to increased recoverable capital spending	10
Miscellaneous operating revenue(c)	8
DSM revenue due to increased recoverable program spending	6
Other	1
	$137

(a) Primarily due to increased consumption by residential customers as a result of increased cooling and heating degree days and higher energy usage by industrial customers as a result of improved economic conditions and increased cooling and heating degree days.

(b) Primarily due to higher rates effective August 1, 2010. See Note 2 to our Third Quarter Financial Statements, included elsewhere in this offering memorandum, for further discussion of the 2010 Kentucky rate case.

(c) Primarily related to increased late payment charges and transmission service revenues.

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC. Operating expenses follow (In millions of $):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase (Decrease)
Fuel for electric generation	$391	$329	$ 62
Power purchased	135	154	(19)
Other operation and maintenance expenses	251	230	21
Depreciation, accretion and amortization	106	99	7
Total operating expenses	$883	$812	$ 71

Electric Generation Expense

The $62 million increase in fuel for electric generation in the nine months ended September 30, 2010, was primarily due to (In millions of $):

	Increase (Decrease)
Fuel usage volumes due to increased native load and wholesale sales	$ 73
Commodity and transportation costs for coal	(11)
	$62

Power Purchased Expense

The $19 million decrease in power purchased expense in the nine months ended September 30, 2010, was primarily due to (In millions of $):

	Increase (Decrease)
Third-party purchased volumes for native load	$(16)
Purchases from LG&E due to volume(a)	(13)
Demand payments for third-party purchases	(5)
Prices for purchases used to serve retail customers	7
OMU settlement received in 2009(b)	6
Purchases from LG&E due to fuel costs	2
	$(19)

(a) Primarily due to increased consumption by residential customers at LG&E as a result of increased cooling and heating degree days and increased coal-fired generation outages in the first six months of 2010 and higher energy usage by industrial customers as a result of improved economic conditions and increased cooling and heating degree days. See Note 10 to our Third Quarter Financial Statements, included elsewhere in this offering memorandum, for further discussion of the mutual agreement for wholesale sales and purchases between the Companies.

(b) See Note 9 to our Third Quarter Financial Statements, included elsewhere in this offering memorandum, for further discussion of the OMU settlement.

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $21 million in the nine months ended September 30, 2010, due to $19 million of increased other operation expenses and $2 million of increased maintenance expenses.

Other Operation Expenses

The $19 million increase in other operation expenses in the nine months ended September 30, 2010 was primarily due to (in millions of $):

	Increase (Decrease)
Transmission expense(a)	$ 7
Administrative and general(b)	6
Steam expense due to increased generation in 2010	5
Other	1
	$19

(a) Primarily due to transmission expense for a third party pursuant to a settlement agreement, the establishment of a regulatory asset approved by the Kentucky Commission for the EKPC settlement in 2009, net of nine months of amortization expense recorded in 2010, and increased transmission expense due to transmission charges for FERC jurisdictional municipal customers now unbundled from energy.

(b) Primarily due to increased bad debt expense due to higher billed revenues, implementation of a late payment charge and a higher net charge-off percentage, increased labor costs, and increased insurance cost.

Interest Expense to Affiliated Companies

The $4 million increase in interest expense to affiliated companies in the nine months ended September 30, 2010, was primarily due to increased intercompany notes outstanding.

Income Tax Expense

See Note 7 to our Third Quarter Financial Statements, included elsewhere in this offering memorandum, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and our income tax expense.

Liquidity and Capital Resources

	September 30, 2010	December 31, 2009
	(in millions)	
Cash and cash equivalents	$ 2	$ 2
Current portion of long-term debt	228	228
Current portion of long-term debt to affiliated company	33	33
Notes payable to affiliated company	61	45

Activity in our cash and cash equivalents in the nine months ended September 30, 2010, included the following:

	Increase (Decrease) (In millions)
Cash provided by operating activities	$ 300
Construction expenditures	(218)
A net increase in short-term borrowings from affiliated company	16
Expenditures to purchase assets from affiliate	(48)
Payment of dividends	(50)
	$ —

We use net cash generated from our operations, external financing, financing from affiliates and/or infusions of capital from our Parent mainly to fund construction of plant and equipment. As of September 30, 2010, we had a working capital deficiency of $205 million, primarily due to the terms of certain tax-exempt bonds totaling $228 million which allow the investors to put the bonds back to the Company causing them to be classified as current portion of long-term debt. We believe we have adequate liquidity facilities to repurchase any bonds put back to the Company. Working capital deficiencies can be funded through an intercompany money pool agreement or through a syndicated credit facility as described below. We believe that our sources of funds will be sufficient to meet the needs of our business in the foreseeable future.

On November 1, 2010, we entered into a new $400 million unsecured Revolving Credit Agreement, expiring December 31, 2014. Under this credit facility, we have the ability to make cash borrowings and to request the lenders to issue letters of credit. Borrowings will generally bear interest at LIBOR-based rates plus a spread, depending upon our senior unsecured long-term debt rating. The new credit facility contains a financial covenant requiring our debt to total capitalization to not exceed 70% and other customary covenants. Under certain conditions, we may request that the facility’s capacity be increased by up to $100 million. This new credit facility replaced an existing bilateral line of credit totaling $35 million that was terminated on the effective date of the new facility.

In addition, we maintain letter of credit facilities under which four letters of credit have been issued totaling $198 million, which support existing pollution control bonds totaling approximately $195 million. We plan to substitute letters of credit issued under our new Revolving Credit Agreement for these letters of credit currently supporting pollution control bonds. After the substitution, we plan to terminate these letter of credit facilities.

We also participate in an intercompany money pool agreement wherein our Parent and/or LG&E make funds available to us at market-based rates (based on highly rated commercial paper issues) up to $400 million.

We, through our Parent, sponsor pension and postretirement benefit plans for our employees. The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under the defined benefit pension plans. The market value of the combined investments, including the impact of benefit payments, within the plans increased by approximately 15% for the year ended December 31, 2009. The benefit plan assets and obligations of our Parent and the Company are remeasured annually using a December 31 measurement date. Investment gains in 2009 resulted in a decrease to the plans’ unfunded status upon actuarial revaluation of the plans, while investment losses in 2008 had the opposite effect. Our 2009 pension cost was approximately $20 million higher than 2008. We anticipate our 2010 pension cost will be approximately $5 million less than the 2009 expense. The amount of future funding will depend upon the actual return on plan assets, the discount rate and other factors, but we fund our pension obligations in a manner consistent with the Pension Protection Act of 2006. In January 2010, we made a voluntary contribution to our pension plan of $13 million.

Future Capital Requirements

Our construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of our service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. At September 30, 2010, we estimated our capital expenditures for the three-year period ending December 31, 2012 to total approximately $1,125 million, consisting primarily of on-going construction related to generation assets totaling approximately $305 million, ash pond and landfill projects totaling approximately $210 million, on-going construction related to distribution assets totaling approximately $245 million, selective catalytic reduction projects totaling approximately $155 million, installation of FGDs on Ghent and Brown units totaling approximately $125 million, information technology projects totaling approximately $35 million, other projects totaling approximately $25 million and construction of TC2 totaling approximately $25 million (including $5 million for environmental controls).

In addition to the amounts above, evolving environmental regulations will likely increase the level of capital expenditures above the amounts currently expected over the next several years. With respect to NAAQS, CATR, CAMR (each as defined and described under "Business — Environmental Matters") replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, we may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Our capital expenditures associated with such actions are preliminarily estimated to be in the $1.7 billion range over the next 10 years, although final costs may substantially vary. With respect to potential developments in water discharge, revised PCB standards, or GHG initiatives, costs in such areas cannot be estimated due to the preliminary status or uncertain outcome of such developments, but would be in addition to the above amounts and could be substantial. See Note 9 to our Third Quarter Financial Statements, included elsewhere in this offering memoran- dum, for further discussion of environmental matters.

Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. Credit market conditions can affect aspects of the availability, terms or methods in which we fund our capital requirements. We anticipate funding future capital requirements through operating cash flow, issuance of debt (including issuance of first mortgage bonds) and/or infusions of capital from our Parent.

We have a variety of funding alternatives available to meet our capital requirements. We maintain a $400 million unsecured revolving credit facility with a maturity date of December 31, 2014, and we participate in an intercompany money pool arrangement wherein our Parent and/or LG&E make funds of up to $400 million available to the Company at market-based rates.

Regulatory approvals are required for the Company to incur additional debt. The Virginia Commission and the FERC authorize the issuance of short-term debt while the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In November 2009, we received a two- year authorization from the FERC to borrow up to $400 million in short-term funds. We also have authorization from the Virginia Commission that expires at the end of 2011 allowing short-term borrowing of up to $400 million. We currently believe this authorization provides the necessary flexibility to address any liquidity needs. As of September 30, 2010, we have borrowed $61 million of this authorized amount.

In September 2010 the Kentucky Commission, and in October 2010 the Virginia Commission and the Tennessee Regulatory Authority, issued orders in the Company's respective financing cases associated with the PPL acquisition. The orders each authorized the Company to:

- issue notes to a PPL affiliate to repay previously outstanding debt with an affiliate of E.ON AG;
- issue first mortgage bonds up to $1.556 billion to
  - refund notes due to affiliates and
  - fund our cash needs;
- issue first mortgage bonds to secure and collateralize existing pollution control debt obligations;
- enter into and perform obligations under hedging agreements in connection with the issuance of the above first mortgage bonds; and
- enter into a multi-year revolving credit facility in an amount not to exceed $400 million.

See Notes 7, 8 and 9 to our 2009 Annual Financial Statements and Notes 8 and 9 to our Third Quarter Financial Statements, each included elsewhere in this offering memorandum, for additional information.

Contractual Obligations

The following table is provided to summarize contractual cash obligations, as estimated by the Company at December 31, 2009. We anticipate cash from operations and external financing will be sufficient to fund future obligations.

Contractual Cash Obligations	Payments Due by Period 2010	2011	2012	2013	2014	Thereafter	Total
				(In millions)			
Short-term debt(a)	$ 45	$ —	$ —	$ —	$ —	$ —	$ 45
Long-term debt(b)(j)	33	—	50	175	100	1,324(b)	1,682
Interest on long-term debt to affiliated company(c)(k)	73	72	71	67	61	424	768
Interest on fixed rate bonds(d)	2	2	2	2	2	21	31
Operating leases(e)	7	6	5	4	4	3	29
Unconditional power purchase obligations(f)	16	10	10	11	12	177	236
Coal and gas purchase obligations(g)	391	307	145	88	92	—	1,023
Postretirement benefit plan obligations(h)	5	6	6	6	6	34	63
Other obligations(i)	57	5	—	—	—	—	62
Total contractual cash obligations	$629	$408	$289	$353	$277	$1,983	$3,939

(a) Represents borrowings from affiliated company due within one year.

(b) Includes $228 million of pollution control bonds classified as current liabilities, which bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. Maturity dates for these bonds range from 2023 to 2034.

(c) Represents future interest payments on long-term debt to affiliated company.

(d) Represents interest on fixed rate long-term bonds. Future interest obligations on variable rate long-term bonds cannot be quantified.

(e) Represents future operating lease payments.

(f) Represents future minimum payments under OMU and Ohio Valley Electric Corporation power purchase agreements through May 2010 and 2026, respectively.

(g) Represents contracts to purchase coal and natural gas transportation. Obligations for 2015 and 2016 are indexed to future market prices and are not included above, since prices will be set in the future using the contracted methodology.

(h) Represents currently projected cash flows for the postretirement benefit plan as calculated by the actuary.

(i) Represents construction commitments, including commitments for TC2 and the FGDs.

(j) Includes long-term debt to affiliate of $1,298 million in long-term debt and $33 million in short-term debt, which was replaced with other affiliate borrowings at the time of the PPL acquisition of our Parent, which borrowings will be repaid with proceeds of the Bonds.

(k) Debt to affiliate will be repaid with the proceeds of the Bonds, thereby modifying future interest obligations.

Off-Balance Sheet Arrangements

We have very limited off-balance sheet activity. See Note 9 to our 2009 Annual Financial Statements, included elsewhere in this offering memorandum, for more information.

Climate Change

As a company with significant coal-fired generating assets, we could be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, establishing additional requirements for the handling or disposal of coal combustion byproducts, or addressing other environmental matters. However, the precise impact on our operations, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the finalization of such requirements.

The cost to the Company and the effect on our business of complying with potential GHG restrictions will depend upon the details of the programs ultimately enacted. Some of the design elements which may have the greatest effect on the Company include (a) the required levels and timing of any carbon caps or limits, (b) the emission sources covered by such caps or limits, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant GHG-reduction technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to GHG limits. While the costs to comply with future GHG developments are not currently determinable, such costs could be significant.

Ultimately, environmental matters or potential environmental matters represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. While we currently anticipate that many of such direct costs or effects may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change matters could result in material effects on our results of operations, liquidity and financial condition.

Growing global, national and local attention to climate change matters has led to the development of various international, federal, regional and state laws and regulations directly or indirectly relating to emissions of GHGs, including carbon dioxide, which is emitted from the combustion of fossil fuels such as coal and natural gas, as occurs at our generating stations. In particular, beginning in January 2011, GHG emissions from stationary sources, including our generating assets, will be subject to regulation by the EPA under the Prevention of Significant Deterioration and Title V provisions of the federal Clean Air Act through the GHG "tailoring" rule. Other developing laws and regulations include a variety of mechanisms and structures to regulate GHGs, including direct limits or caps, emission allowances or taxes, renewable generation requirements or standards and energy efficiency or conservation measures, and may require investments in transmission, alternative fuel or carbon sequestration or other emission reduction technologies. See "Business — Environmental Matters," Note 9 to our 2009 Annual Financial Statements and Note 9 to our Third Quarter Financial Statements, each included elsewhere in this offering memorandum, for additional information.

Quantitative and Qualitative Disclosures about Market Risk

We conduct energy trading and risk management activities to maximize the value of power sales from physical assets we own. Energy trading activities are principally forward financial transactions to manage price risk and are accounted for as non-hedging derivatives on a mark-to-market basis in accordance with the derivatives and hedging topic of the Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC").

The Company manages its cost of borrowing by utilizing both fixed and floating rate debt. The exposure to floating rate debt can be mitigated through the use of interest rate swaps. We currently do not have any interest rate swaps in place.

For more information, see Note 3 to our 2009 Annual Financial Statements and Note 4 to our Third Quarter Financial Statements, each included elsewhere in this offering memorandum.

Critical Accounting Policies/Estimates

Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied has not changed. Specific risks for these critical accounting policies are described in the notes to our audited and unaudited financial statements included elsewhere in this offering memorandum. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Events rarely develop exactly as forecasted, and the best estimates routinely require adjustment.

Recent accounting pronouncements and critical accounting policies and estimates including unbilled revenue, allowance for doubtful accounts, regulatory mechanisms, pension and postretirement benefits and income taxes are detailed in Notes 1, 2, 5, 6 and 9 to our 2009 Annual Financial Statements and Notes 1, 2, 6, 7 and 9 to our Third Quarter Financial Statements, each included elsewhere in this offering memorandum.

Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

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

As of December 31, 2009, we are not subject to the internal control and other requirements of the Sarbanes- Oxley Act of 2002 and associated rules ("Sarbanes-Oxley") and consequently are not required to evaluate the effectiveness of our internal control over financial reporting pursuant to Section 404 of Sarbanes-Oxley. However, management has assessed the effectiveness of our internal control over financial reporting as of December 31, 2009, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control — Integrated Framework.* Management has concluded that, as of December 31, 2009, our internal control over financial reporting was effective based on those criteria. There have been no changes in our internal control over financial reporting that occurred during the twelve months ended December 31, 2009, or during the nine months ended September 30, 2010, that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

The effectiveness of our internal control over financial reporting as of December 31, 2009, has been audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included within our 2009 Annual Financial Statements included elsewhere in this offering memorandum.

RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth the Company's ratio of earnings to fixed charges for the nine months ended September 30, 2010 and for the years ended December 31, 2009, 2008, 2007, 2006 and 2005. Our ratios of earnings to fixed charges for the periods indicated are as follows:

	2005	2006	2007	2008	2009	9-Months Ended September 2010
			(In millions)			
Earnings:						
Income from continuing operations before income taxes	$ 176	$ 226	$ 244	$ 226	$ 200	$ 205
Exclude amounts reflected in line above:						
Undistributed income of Electric Energy, Inc.	2	2	5	—	(11)	4
Mark to market impact of derivative instruments(1)	1	—	—	1	(1)	—
Add fixed charges (see below)	34	41	59	77	79	63
Total Earnings	$ 207	$ 265	$ 298	$ 302	$ 291	$ 264
Fixed charges:						
Interest expense	$ 31	$ 39	$ 57	$ 74	$ 76	$ 61
Estimated interest component of rental expense	1	2	2	3	3	2
Preferred stock dividends	2	—	—	—	—	—
Total Fixed Charges	$ 34	$ 41	$ 59	$ 77	$ 79	$ 63
Ratio of Earnings to Fixed Charges	6.09	6.46	5.05	3.92	3.68	4.19

(1) Represents non-cash unrealized gains or losses on derivative instruments recorded in the statements of income.

Earnings, for purposes hereof, consist of earnings from continuing operations (as defined below) plus fixed charges. Fixed charges consist of all interest on indebtedness, amortization of debt discount and expense and the portion of rental expense that represents an imputed interest component. Earnings from continuing operations consist of income before taxes, undistributed income of EEI, and the mark-to-market impact of derivative instruments.

PRO FORMA RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth the Company's ratio of earnings to fixed charges for the nine months ended September 30, 2010 and for the year ended December 31, 2009, adjusted for the sale of the Bonds.

	2009	9-Months Ended September 2010
	(In millions)	
Earnings:		
Income from continuing operations before income taxes	$ 200	$ 205
Adjustments to Income(1)	10	11
Exclude amounts reflected in line above:		
Undistributed income of Electric Energy, Inc.	(11)	4
Mark to market impact of derivative instruments(2)	(1)	—
Add fixed charges (see below)	69	52
Total Earnings	$ 291	$ 264
Fixed charges:		
Interest expense	$ 76	$ 61
Adjustments to interest expense(1)	(10)	(11)
Estimated interest component of rental expense	3	2
Preferred stock dividends	—	—
Total Fixed Charges	$ 69	$ 52
Ratio of Earnings to Fixed Charges	4.22	5.08

(1) Adjusted to give effect to the estimated net decrease in interest expense from refinancing using an average interest rate of 3.9%.

(2) Represents non-cash unrealized gains or losses on derivative instruments recorded in the statements of income.

Earnings, for purposes hereof, consist of earnings from continuing operations (as defined below) plus fixed charges. Fixed charges consist of all interest on indebtedness, amortization of debt discount and expense and the portion of rental expense that represents an imputed interest component. Earnings from continuing operations consist of income before taxes, undistributed income of Electric Energy, Inc. ("EEI"), and the mark-to-market impact of derivative instruments.

BUSINESS

Overview

Kentucky Utilities Company, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. We provide electric service to approximately 515,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 29,000 customers in 5 counties in southwestern Virginia and to 5 customers in Tennessee. Our service area covers approximately 6,600 square miles. During the first three quarters of 2010, approximately 99% of the electricity generated by us was produced by our coal-fired electric generating stations. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines ("CTs"). In Virginia, we operate under the name Old Dominion Power Company. We also sell wholesale electric energy to 12 municipalities.

Our affiliate, Louisville Gas and Electric Company ("LG&E"), is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution and sale of natural gas in Kentucky. We and LG&E became indirect wholly-owned subsidiaries of PPL Corporation on November 1, 2010.

Operations

The sources of our operating revenues and volume of sales for the year ended December 31, 2009 were as follows:

	Revenue	**% Revenue**	**Volume**	**% Volume**
	($ in millions. Volume in GWH)			
Industrial & Commercial	$ 637	47%	10,171	49%
Residential	480	35%	6,594	31%
Municipals	91	7%	1,848	9%
Other Retail	118	9%	1,647	8%
Wholesale(1)	29	2%	660	3%
Total	**$1,355**	**100%**	**20,920**	**100%**

(1) Includes transactions between the Company and LG&E

Our business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year. We frequently experience dual peaks in winter and summer; our peak load in 2009 of 4,640 megawatts ("Mw") occurred on January 16, when the temperature reached a low of
- 3 degrees Fahrenheit in Lexington.

Our retail electric rates contain a FAC, whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The FAC allows us to adjust customers' accounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Refunds to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

Kentucky law permits us to recover the costs of complying with the Federal Clean Air Act, including a return of operating expenses, and a return of and on capital invested, through the environmental cost recovery ("ECR") mechanism. Pursuant to this mechanism, a regulatory asset or liability is established in the amount that has been under- or over-recovered due to timing or adjustments to the mechanism. This mechanism includes construction work in progress and a return on equity, currently set at 10.63%.

We have contracts with the Tennessee Valley Authority ("TVA") to act as our transmission Reliability Coordinator and Southwest Power Pool, Inc. ("SPP") to function as our independent transmission operator, pursuant to FERC requirements. With respect to certain of these matters, we have submitted filings with the FERC and the Kentucky Commission proposing to approve agreed-upon continuations of these arrangements beyond their previous September 2010 expiration dates. The Kentucky Commission approved the continuation of this arrangement on October 27, 2010, and FERC approval is anticipated in 2010.

We and LG&E jointly dispatch our generation units with the lowest cost generation used to serve retail native load. When we have excess generation capacity after serving our own retail native load and our generation cost is lower than that of LG&E, LG&E purchases electricity from us. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of ours, we purchase electricity from LG&E. These transactions are recorded as intercompany wholesale sales and purchases and are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the two companies. The volume of energy each company has to sell to the other is dependent upon its native load needs and its available generation. See Note 11 to our 2009 Annual Financial Statements and Note 10 to our Third Quarter Financial Statements, each included elsewhere in this offering memorandum.

Properties

Our power generating system includes coal-fired units operated at our four steam generating stations. Natural gas and oil fueled CTs supplement the system during peak or emergency periods. As of December 31, 2009, we owned all or a portion of, and operated the following generating stations* while targeting a 13%-15% reserve margin:

Plant	Location	2009 Heat Rate (Btu/KWh)	Plant Type	Fuel	Summer Capability Rating (Mw)	2009 Generation GWh
Steam Turbines						
Ghent-Units 1-4	Carroll County, KY	10,882	ST	Coal	1,918	11,346
E.W. Brown — Units 1-3	Mercer County, KY	10,630	ST	Coal	697	2,505
Green River — Units 3-4	Muhlenberg County, KY	11,352	ST	Coal	163	625
Tyrone-Unit 3	Woodford County, KY	13,156	ST	Coal	71	24
Total Coal-fired Generation					**2,849**	**14,500**
Combustion Turbines						
Trimble County — Units 5-10	Trimble County, KY	11,603	CT	Gas	632	129
E.W. Brown — Units 5-11	Mercer County, KY	15,424	CT	Gas	757	56
Secondary CTs	Fayette/Jefferson County, KY	57,458	CT	Gas	110	0
Total Gas-fired Generation					**1,499**	**185**
Hydroelectric Stations						
Dix Dam	Mercer County, KY	NA	NA	Hydro	24	69
Total Hydroelectric Generation					**24**	**69**
In Construction						
Trimble County — Unit 2**	Trimble County, KY	NA	ST	Coal	NA	NA
Grand Total					**4,372**	**14,754**

* Some of these units are jointly owned with LG&E and others (capability ratings reflect our ownership share). See Note 10 to our 2009 Annual Financial Statements, included elsewhere in this offering memorandum, for information regarding jointly-owned units.

** At November 1, 2010, TC2, a new 760-Mw capacity base-load, coal fired unit that will be jointly owned by the Company (60.75%) and LG&E (14.25%) and unrelated third parties, remains under construction with completion expected by year-end 2010.

At December 31, 2009, our transmission system included 130 substations (52 of which are shared with the distribution system) with a total capacity of approximately 13,016 Megavolt-ampere ("MVA") and approximately 4,040 miles of lines. The distribution system included 479 substations (52 of which are shared with the transmission system) with a total capacity of approximately 6,973 MVA, 14,136 miles of overhead lines and 2,209 miles of underground conduit.

Substantially all of our real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity, subject to certain exclusions and exceptions, is subject to the lien of the Mortgage, as described in "Description of the Bonds — Security; Lien of the Mortgage."

We own 20% of the common stock of EEI, which owns and operates a 1,162-Mw generating station in southern Illinois. EEI generally sells its production into the wholesale market. Additional information regarding property and investments is provided in Notes 1, 9 and 10 to our 2009 Annual Financial Statements and Note 9 to our Third Quarter Financial Statements, each included elsewhere in this offering memorandum.

Construction and Future Capital Requirements

The Company and LG&E are currently constructing a new 760-Mw capacity base-load, coal fired unit, TC2, which will be jointly owned by the Company (60.75%) and LG&E (14.25%), together with the Illinois Municipal Electric Agency and the Indiana Municipal Power Agency. Each owner is responsible for its proportionate share of the capital cost during construction, and fuel, operation and maintenance cost when TC2 begins operation , which is scheduled to occur by year-end 2010. The contract price and its components attributable to us, currently approximating $697 million (including $192 million for environmental controls) are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor.

Our construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of our service area and to comply with environmental regulations. These needs are continually being reassessed, and appropriate revisions are made, when necessary, in construction schedules. At September 30, 2010, we estimated our capital expenditures for the three-year period ending December 31, 2012, including those for TC2, to total approximately $1.1 billion, consisting primarily of the following:

	($ in millions)
Construction of generation assets	$ 305
Construction of distribution assets	245
Ash pond and landfill projects	210
Brown SCR	155
Installation of FGDs on Ghent and Brown units	125
Information technology projects	35
Other projects	25
Construction of TC2 (includes $5 million for environmental controls)	25
	$1,125

In addition to the amounts above, evolving environmental regulations will likely increase the level of capital expenditures over the next several years. See "Business — Environmental Matters." Future capital requirements may be affected in varying degrees by factors such as electric energy demand, load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates, further changes in environmental regulations and other regulatory requirements. Credit market conditions can affect aspects of the availability, terms or methods in which we fund our capital requirements. We anticipate funding future capital requirements through operating cash flow, debt and/or infusions of capital from our Parent.

For a discussion of liquidity, capital resources and financing activities, see "Management's Discussion and Analysis."

Coal Supply

Coal-fired generating units provided approximately 99% of our net kilowatt-hour (“Kwh”) generation for 2009. The remaining net generation for 2009 was provided by natural gas and oil fueled CT peaking units and a hydroelectric plant. Coal is expected to be the predominant fuel used by us in the foreseeable future, with natural gas and oil being used for peaking capacity and flame stabilization in coal-fired boilers or in emergencies. We have no nuclear generating units and have no plans to build any in the foreseeable future.

Fuel inventory is maintained at levels estimated to be necessary to avoid operational disruptions at the coal-fired generating units. Reliability of coal deliveries can be affected from time to time by a number of factors including fluctuations in demand, coal mine production issues and other supplier or transporter operating difficulties.

We have entered into coal supply agreements with various suppliers for coal deliveries for 2010 and beyond, and normally augment our coal supply agreements with spot market purchases. We have a coal inventory policy which we believe provides adequate protection under most contingencies.

For our existing units, we expect to continue purchasing coal from western and eastern Kentucky, West Virginia, southern Indiana, southern Illinois and Ohio for the foreseeable future. With the installation of FGDs, we expect our use of higher sulfur coal to increase. Following commercial operation of the new TC2 unit, we may purchase small quantities of ultra low sulfur content coal from Wyoming for blending. Coal is delivered to our generating stations by a mix of transportation modes, including barge, truck and rail.

Rates and Regulation

We are subject to the jurisdiction of the Kentucky Commission, the Virginia Commission, the Tennessee Regulatory Authority and the FERC in virtually all matters related to electric utility regulation, and as such, our accounting is subject to the regulated operations guidance of the FASB ASC. Given our competitive position in the marketplace and the status of regulation in Kentucky and Virginia, there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

Our Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and notes payable) including certain regulatory adjustments to exclude non-regulated investments and environmental compliance plans recovered separately through the ECR mechanism. Currently, none of the regulatory assets or regulatory liabilities are excluded from the return on capitalization utilized in the calculation of Kentucky base rates; therefore, a return is earned on all Kentucky regulatory assets. Our Virginia base rates are calculated based on a return on rate base (net utility plant less deferred taxes and miscellaneous deductions). All regulatory assets and liabilities are excluded from the return on rate base utilized in the calculation of Virginia base rates.

PPL Acquisition. In September 2010, the Kentucky Commission approved the September 2010 settlement agreement among PPL and all of the intervening parties to PPL’s joint application to the Kentucky Commission for approval of its acquisition of ownership and control of our Parent, the Company and LG&E. In the settlement, the parties agreed that we and LG&E would commit that no base rate increases would take effect before January 1, 2013. The Company’s rate increase that took effect on August 1, 2010 (as described below) will not be impacted by the settlement. Under the terms of the settlement, we retain the right to seek approval for the deferral of “extraordinary and uncontrollable costs.” Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and DSM recovery mechanisms. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Company file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits the Company to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. The Kentucky Commission order and the settlement agreement contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In October 2010, both the Virginia Commission and the Tennessee Regulatory Authority approved the transfer of control of the Company from E.ON US Investments Corp. to PPL. Each of these orders contained certain

commitments with regard to operations, workforce, community involvement and other matters.

In October 2010, the FERC approved the September 2010 settlement agreement among the Company, LG&E, other applicants and protesting parties. The settlement agreement includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain of our municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that we have agreed to not seek the same transaction- related cost from retail customers and agreements to coordinate with protesters in certain open or on-going matters.

Kentucky Rate Case. In January 2010, we filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. We requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates were suspended until August 1, 2010. A number of intervenors entered the rate case, including the office of the Attorney General of Kentucky (the "AG") Kentucky Attorney General's office, certain representatives of industrial and low-income groups and other third parties, and submitted filings chal- lenging our requested rate increases, in whole or in part. A hearing was held on June 8, 2010. We and all of the intervenors except the AG agreed to a stipulation providing for an increase in electric base rates of $98 million on an annual basis and filed a request with the Kentucky Commission to approve such stipulation. In July 2010, the Kentucky Commission issued an order in the proceeding approving all the provisions of the stipulation, with rates effective on and after August 1, 2010.

Virginia Rate Case. In June 2009, we filed an application with the Virginia Commission requesting an increase in electric base rates for our Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. During December 2009, we and the Virginia Commission Staff agreed to a stipulation and recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. A public hearing was held during January 2010. As permitted, pursuant to a Virginia Commission order, we elected to implement the proposed rates effective November 1, 2009, on an interim basis. In March 2010, the Virginia Commission issued an order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, we refunded approximately
$1 million in interim rate amounts in excess of the ultimate approved rates. During August 2010, a report was filed with the Virginia Commission detailing the costs of the refunds, the accounts charged and confirming that applicable refunds had been applied.

FERC Wholesale Rate Case. In September 2008, we filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rate to an unbundled formula rate, including an annual adjustment mechanism. In May 2009, the FERC issued an order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, we submitted to the FERC the proposed current annual adjustment to the formula rate. This updated rate became effective on July 1, 2010, subject to certain review procedures by the wholesale requirements customers and the FERC, including potential refunds in the case of disallowed costs or charges.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether we must allocate to the municipal customers a portion of renewable resources we may be required to procure on behalf of our retail ratepayers. In August 2009, the FERC accepted the issue for briefing and the parties completed briefing submissions during 2009. An order was issued by the FERC in July 2010, indicating that we are not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

Refund of Over-Collected Amounts. On July 15, 2010, our Parent, on behalf of the Company and LG&E, submitted an informational filing indicating it had inadvertently over-collected certain costs related to the independent transmission organization and reliability coordinator in rates charged pursuant to the Attachment O formula rate included in the companies' open access transmission tariff. Total refunds being issued in connection with the inadvertent recovery are approximately $1.2 million. No action has been taken by FERC with respect to
this informational filing.

Storm Restoration. In January 2009, a significant ice storm passed through our service territory causing approximately 199,000 customer outages and was followed closely by a severe wind storm in February 2009 that caused approximately 44,000 customer outages. We incurred $57 million in incremental operation and maintenance expenses and $33 million in capital expenditures related to the restoration following the two storms. We filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an order allowing us to establish a regulatory asset of up to $62 million based on our actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, we established a regulatory asset of $57 million for actual costs incurred. We received approval in our current base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service territory causing significant outages and system damage. In October 2008, we filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, approximately
$3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an order allowing us to establish a regulatory asset of up to $3 million based on our actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, we established a regulatory asset of $2 million for actual costs incurred. We received approval in our current electric base rate cases to recover this asset over a ten year period beginning August 1, 2010.

2008 Rate Case. In July 2008, we filed an application with the Kentucky Commission requesting an increase in base electric rates. In conjunction with the filing of the application for a change in base rates, based on previous orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008. The VDT surcredit was a regulatory mechanism that reduced rates as the result of changes made to reduce operating costs following a previous acquisition transaction involving our Parent. In February 2009, the Kentucky Commission issued an order approving a settlement agreement among us, the AG, the Kentucky Industrial Utility Consumers, Inc. and all other parties to the rate case, under which our base electric rates decreased by $9 million annually effective February 6, 2009, at which time the merger surcredit (which originated as part of our Parent's merger with KU Energy Corporation in 1998) terminated.

Rate Mechanisms

FAC. Our retail electric rates contain a FAC, whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The FAC allows us to adjust customers' accounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Credits to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. A regulatory asset or liability is established in the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

ECR. Kentucky law permits us to recover the costs of complying with the Federal Clean Air Act and those federal, state and local environmental requirements that apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal, including a return of operating expenses, and a return of and on capital invested, through the ECR mechanism. Pursuant to this mechanism, a regulatory asset or liability is established in the amount that has been under- or over-recovered due to timing or adjustments to the mechanism. This mechanism includes construction work in progress and a return on equity, currently set at 10.63%.

DSM. Our rates contain a DSM provision which includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows us to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

For a further discussion of current rates and regulatory matters, see Notes 2, 9 and 12 to our 2009 Annual Financial Statements and Notes 2 and 9 to our Third Quarter Financial Statements, included elsewhere in this offering memorandum.

Environmental Matters

General. Protection of the environment is a major priority for us and a significant element of our business activities. Our properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, we must conduct our operations in accordance with numerous permit and other require- ments issued under or contained in such laws or regulations.

Climate Change. Growing global, national and local attention to climate change matters has led to the development of various international, federal, regional and state laws and regulations directly or indirectly relating to emissions of GHGs, including carbon dioxide, which is emitted from the combustion of fossil fuels such as coal and natural gas, as occurs at our generating stations. In particular, beginning in January 2011, GHG emissions from stationary sources, including our generating assets, will be subject to regulation by the EPA under the Prevention of Significant Deterioration and Title V provisions of the federal Clean Air Act through the GHG “tailoring” rule. Other developing laws and regulations include a variety of mechanisms and structures to regulate GHGs, including direct limits or caps, emission allowances or taxes, renewable generation requirements or standards and energy efficiency or conservation measures, and may require investments in transmission, alternative fuel or carbon sequestration or other emission reduction technologies.

While the final terms and impacts of such developments cannot be estimated, we, as a primarily coal-fired utility, could be adversely affected. Among other emissions, GHGs include carbon-dioxide, which is produced via the combustion of fossil-fuels such as coal and natural gas. Our generating fleet is approximately 63% coal-fired, 37% oil/gas-fired and less than 1% hydroelectric based on capacity. During 2009, we produced approximately 99% of our electricity from coal and 1% from natural gas combustion, on a megawatt-hours basis. During 2009, our emissions of GHGs were approximately 14.2 million metric tons of carbon-dioxide equivalents from our owned or controlled generation sources. While our generation activities account for the bulk of our GHG emissions, other GHG sources at the Company include operation of motor vehicles and powered equipment, evaporation associated with gas pipelines, refrigerating equipment and similar activities.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as National Ambient Air Quality Standards (“NAAQS”). Each state must identify “nonattainment areas” within its boundaries that fail to comply with the NAAQS and develop a state implementation plan (“SIP”) to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final “NOx SIP Call” rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the Clean Air Interstate Rule (“CAIR”) which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR.

In July 2008, a federal appeals court issued a ruling finding deficiencies in the CAIR and vacating it. In December 2008, the Court amended its previous order, directing the EPA to promulgate a new regulation, but leaving the CAIR in place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and our compliance plans relating thereto, due to the interconnection of the CAIR with such associated programs.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS for nitrogen dioxide (“NO_2”) and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS, our power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions.

In July 2010, the EPA issued the proposed the Clean Air Transport Rule (“CATR”), which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012 and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on alternative approaches, including one which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional “transport” rules to address compliance with revised NAAQS for ozone and particulate matter which will be issued by the EPA in the future, as discussed below.

Hazardous Air Pollutants. As provided in the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the Clean Air Mercury Rule (“CAMR”) establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a “co-benefit” of the controls installed for purposes of compliance with the CAIR. In addition, in 2006, the Metro Louisville Air Pollution Control District adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has entered into a consent decree requiring it to promulgate a utility Maximum Achievable Control Technology rule to replace the CAMR, with a proposed rule due by March 2011 and a final rule due by November 2011. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations.

Ash Ponds and Coal-Combustion Byproducts. The EPA has undertaken various initiatives in response to a December 2008 impoundment failure at the TVA’s Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including the Company, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of our impoundments, which the EPA found to be in satisfactory condition except for certain impoundments at the Mill Creek and Cane Run stations, which were determined to be in fair condition. In June 2010, the EPA published proposed regulations for the management of coal combustion byproducts. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts.

Water Discharges and PCB Regulations. The EPA has also announced plans to develop revised effluent limitation guidelines governing discharges from power plants and standards for cooling water intake structures. The EPA has further announced plans to develop revised standards governing the use of polychlorinated biphenyls (“PCBs”) in electrical equipment. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized.

Impact of Pending and Future Environmental Developments. As a company with significant coal-fired generating assets, we will likely be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. These evolving environmental regulations will likely require an increased level of capital expenditures and increased incremental operating and maintenance costs by us over the next several years. Due to the uncertain nature of the final regulations that will ultimately be adopted by the EPA, including the reduction targets and the deadlines that will be applicable, we cannot finalize estimates of the potential compliance costs, but should the final rules incorporate additional emission reduction requirements, require more stringent emissions controls or implement more stringent byproducts storage and disposal practices, such costs will likely be significant. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, we may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Our capital expenditures associated with such actions are prelim- inarily estimated to be in the $1.7 billion range over the next 10 years, although final costs may substantially vary. With respect to potential developments in water discharge, revised PCB standards or GHG initiatives, costs in such areas cannot be estimated due to the preliminary status or uncertain outcome of such developments, but would be in addition to the above amount and could be substantial. Ultimately, the precise impact on our operations of these various environmental developments cannot be determined prior to the finalization of such requirements. Based on prior regulatory precedent, we believe that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but we can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

Environmental laws and regulations applicable to our business and governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contaminants and employee health and safety are discussed in Notes 2 and 9 to our 2009 Annual Financial Statements and Notes 2 and 9 to our Third Quarter Financial Statements, each included elsewhere in this offering memorandum.

State Executive or Legislative Matters

In November 2008, the Governor of Kentucky issued an action plan to create efficient, sustainable energy solutions and strategies and move toward state energy independence. The plan outlines the following seven strategies to work toward these goals:

- Improve the energy efficiency of Kentucky’s homes, buildings, industries and transportation fleet
- Increase Kentucky’s use of renewable energy
- Sustainably grow Kentucky’s production of biofuels
- Develop a coal-to-liquids industry in Kentucky to replace petroleum-based liquids
- Implement a major and comprehensive effort to increase gas supplies, including coal-to-gas in Kentucky
- Initiate aggressive carbon capture/sequestration projects for coal-generated electricity in Kentucky
- Examine the use of nuclear power for electricity generation in Kentucky

In December 2009, the Governor of Kentucky’s Executive Task Force on Biomass and Biofuels issued a final report to establish potential strategic actions to develop biomass and biofuels industries in Kentucky. The plan noted the potential importance of biomass as a renewable energy source available to Kentucky and discussed various goals or mechanisms, such as the use of approximately 25 million tons of biomass for generation fuel annually, allotment of electricity and gas taxes and state tax credits to support biomass development.

In January 2010, a state-established Kentucky Climate Action Plan Council commenced formal activities. The council, which includes governmental, industry, consumer and other representatives, seeks to identify possible Kentucky responses to potential climate change and federal legislation, including increasing statewide energy efficiency, energy independence and economic growth. The council has established various technical work groups, including in the areas of energy supply and energy efficiency/conservation, to provide input, data and recommendations.

During prior legislative sessions, various bills have been introduced in the Kentucky General Assembly with respect to environmental or utility matters, including potential renewable energy portfolio requirements, energy conservation measures, coal mining or coal byproduct operations and other matters. It is expected that similar legislation will be introduced in upcoming sessions, but the prospects and final terms of any such legislation cannot be determined.

Legislative and regulatory actions as a result of these proposals and their impact on the Company, which may be significant, cannot currently be predicted.

Competition

There are currently no other electric public utilities operating within our service area. At this time, neither the Kentucky General Assembly nor the Kentucky Commission has adopted or approved a plan or timetable for retail electric industry competition in Kentucky. The nature or timing of the ultimate legislative or regulatory actions regarding industry restructuring and their impact on us, which may be significant, cannot currently be predicted. Virginia, formerly a deregulated jurisdiction, has enacted legislation which implements a hybrid model of cost- based regulation.

Employees and Labor Relations

We had 964 full-time regular employees at December 31, 2009, 149 of which were operating, maintenance and construction employees represented by the IBEW (“International Brotherhood of Electrical Workers”) Local 2100 and the United Steelworkers of America (“USWA”) Local 9447-01. Effective August 4, 2009, we and our employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement. The agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. We and employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2008. This agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers.

Related Party Transactions

We, our Parent and subsidiaries of our Parent engage in related party transactions. See Note 11 to our 2009 Annual Financial Statements and Note 10 to our Third Quarter Financial Statements, each included elsewhere in this offering memorandum, for more information.

Legal Proceedings

For a description of the significant legal proceedings, including, but not limited to, certain rates and regulatory, environmental, climate change and litigation matters, involving the Company, reference is made to the information in Note 9 to our 2009 Annual Financial Statements and Note 9 to our Third Quarter Financial Statements, each included elsewhere in this offering memorandum.

In connection with an administrative proceeding alleging a violation by a former Argentine subsidiary of our Parent under that country’s 2002-2003 emergency currency exchange laws, claims are pending against the subsidiary’s then directors, including two individuals who are executive officers of the Company, in a specialized Argentine financial criminal court. Under applicable Argentine laws, directors of a local company may be liable for monetary penalties for a subject company’s violations of the currency laws. The subsidiary and the relevant executive officers believe their actions were in compliance with the relevant laws and have presented defenses in the administrative and criminal proceedings. Our Parent has standard indemnification arrangements with its executive officers. The former subsidiary is now owned by a third-party, which has agreed to indemnify our Parent and the relevant executive officers.

In the normal course of business from time to time, other lawsuits, claims, environmental actions and other governmental proceedings arise against the Company. To the extent that damages are assessed in any of these actions or proceedings, the Company believes that its insurance coverage is adequate. Although we cannot accurately predict the amount of any liability that may ultimately arise with respect to such matters, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on the Company’s financial condition or results of operations.

EXECUTIVE AND FINANCIAL OFFICERS OF THE COMPANY

As of November 1, 2010:

Name	Age	Position	Effective Date of Election to Present Position
Victor A. Staffieri	55	Chairman of the Board, President and Chief Executive Officer Before he was elected to his current position, Mr. Staffieri was President and Chief Operating Officer of LG&E Energy Corp. ("LG&E Energy," the predecessor to our Parent) from March 1999 to April 2001 (including President of LG&E and the Company from June 2000 to April 2001).	May 2001
John R. McCall	67	Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer Mr. McCall has been Executive Vice President, General Counsel and Corporate Secretary of LG&E Energy and LG&E since July 1994 and of the Company since May 1998.	July 1994
S. Bradford Rives	52	Chief Financial Officer Before he was elected to his current position, Mr. Rives was Senior Vice President — Finance and Controller of LG&E Energy, LG&E and the Company from December 2000 to September 2003.	September 2003
Chris Hermann	63	Senior Vice President — Energy Delivery Before he was elected to his current position, Mr. Hermann was Senior Vice President — Distribution Operations, of LG&E Energy, LG&E and the Company from December 2000 to February 2003.	February 2003
Paula H. Pottinger	53	Senior Vice President — Human Resources Before she was elected to her current position, Ms. Pottinger was Vice President — Human Resources of LG&E Energy, LG&E and the Company from June 2002 to January 2006.	January 2006
Paul W. Thompson	53	Senior Vice President — Energy Services Before he was elected to his current position, Mr. Thompson was Senior Vice President — Energy Services of LG&E Energy from August 1999 to June 2000.	June 2000

Name	Age	Position	Effective Date of Election to Present Position
Kent W. Blake	44	Vice President — Corporate Planning and Development	August 2007
		Before he was elected to his current position, Mr. Blake was Vice President State Rates and Regulation of the Parent, the Company and LG&E from April 2007 to August 2007.	
Daniel K. Arbough	49	Treasurer	December 2000
		In addition to his current position, Mr. Arbough held the positions of Director, Corporate Finance of LG&E Energy, LG&E and the Company from May 1998 to March 2007.	
Valerie L. Scott	54	Controller	January 2005
		Before she was elected to her current position, Ms. Scott was Director, Financial Planning and Accounting — Utility Operations of the Company from September 2002 to December 2004.	

All officers serve in the same capacities at the Company, the Parent and LG&E.

DESCRIPTION OF THE BONDS

The following summary description sets forth certain terms and provisions of the Bonds that we are offering by this offering memorandum. Because this description is a summary, it does not describe every aspect of the Bonds or the Mortgage (as defined below) under which the Bonds will be issued. The Mortgage and its associated documents contain the full legal text of the matters described in this section. This summary is subject to and qualified in its entirety by reference to all of the provisions of the Bonds and the Mortgage, including definitions of certain terms used in the Mortgage. We also include references in parentheses to certain sections of the Mortgage. Whenever we refer to particular sections or defined terms of the Mortgage in this offering memorandum, such sections or defined terms are incorporated by reference herein.

General

We will issue each series of the Bonds as a series of debt securities under our indenture, dated as of October 1, 2010 (as such indenture may be amended and supplemented from time to time, the "Mortgage"), to The Bank of New York Mellon, as trustee (the "Trustee"). The Mortgage effectively does not limit the aggregate principal amount of bonds or other debt securities that may issued thereunder, subject to meeting certain conditions to issuance, including those described below under "Issuance of Additional Mortgage Securities." The Bonds and all other debt securities issued previously or hereafter issued under the Mortgage are collectively referred to herein as "Mortgage Securities." The Mortgage constitutes a first mortgage lien, subject to Permitted Liens and exceptions and exclusions as described below, on substantially all of our real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity. (See "— Security; Lien of the Mortgage" below.) As of the date of this offering memorandum, approximately
$351 million of first mortgage bonds are issued and outstanding under the Mortgage, and have been pledged to secure pollution control revenue bonds issued by various counties in Kentucky on our behalf. See "Summary — Recent Developments — Pollution Control Revenue Bonds."

The Bonds will be issued in fully registered form only, without coupons. The Bonds will be initially represented by one or more fully registered global securities (the "Global Securities") deposited with the Trustee, as custodian for The Depository Trust Company ("DTC"), as depositary, and registered in the name of DTC or DTC's nominee. A beneficial interest in a Global Security will be shown on, and transfers or exchanges thereof will be effected only through, records maintained by DTC and its participants, as described below under "— Book-Entry Only Issuance — The Depository Trust Company." The authorized denominations of the Bonds will be $2,000 and any larger amount that is an integral multiple of $1,000. Except in limited circumstances described below, the Bonds will not be exchangeable for Bonds in definitive certificated form.

The 2015 Bonds are initially being offered in one series in the principal amount of $250,000,000. The 2020 Bonds are initially being offered in one series in the principal amount of $500,000,000. The 2040 Bonds are initially being offered in one series in the principal amount of $750,000,000. We may, without the consent of the Holders of the applicable series of Bonds, increase the principal amount of any series of Bonds and issue additional bonds of the applicable series having the same ranking, interest rate, maturity and other terms (other than the date of issuance and, in some circumstances, the initial interest accrual date and initial interest payment date) as the Bonds, but we will not reopen a series unless the additional bonds are fungible with the previously issued bonds for U.S. federal income tax purposes. Any such additional bonds would, together with the Bonds of the applicable series offered by this offering memorandum, constitute a single series of securities under the Mortgage and may be treated as a single class for all purposes under the Mortgage, including, without limitation, voting waivers and amendments.

Maturity; Interest

The 2015 Bonds will mature on November 1, 2015 and will bear interest from the date of issuance at a rate of 1.625% per annum. The 2020 Bonds will mature on November 1, 2020 and will bear interest from the date of issuance at a rate of 3.250% per annum. The 2040 Bonds will mature on November 1, 2040 and will bear interest from the date of issuance at a rate of 5.125% per annum. Interest will be payable on each series of Bonds on May 1 and November 1 of each year (each, an "Interest Payment Date"), commencing on May 1, 2011, and at maturity (whether at the applicable stated maturity date, upon redemption or acceleration, or otherwise) ("Maturity").

Subject to certain exceptions, the Mortgage provides for the payment of interest on an Interest Payment Date only to persons in whose names the Bonds are registered at the close of business on the Regular Record Date, which will be the April 15 and October 15 (whether or not a Business Day), as the case may be, immediately preceding the applicable Interest Payment Date; except that interest payable at Maturity will be paid to the person to whom principal is paid.

Interest on the Bonds will be calculated on the basis of a 360-day year of twelve 30-day months, and with respect to any period less than a full calendar month, on the basis of the actual number of days elapsed during the period.

Payment

So long as the Bonds are registered in the name of DTC, as depository for the Bonds as described herein under "— Book-Entry Only Issuance — The Depository Trust Company" or DTC's nominee, payments on the Bonds will be made as described therein.

If we default in paying interest on a Bond, we will pay such defaulted interest either

- to Holders as of a special record date between 10 and 15 days before the proposed payment; or
- in any other lawful manner of payment that is consistent with the requirements of any securities exchange on which the Bonds may be listed for trading. (See Section 307.)

We will pay principal of and interest and premium, if any, on the Bonds at Maturity upon presentation of the Bonds at the corporate trust office of The Bank of New York Mellon in New York, New York, as our Paying Agent. In our discretion, we may change the place of payment on the Bonds, and we may remove any Paying Agent and may appoint one or more additional Paying Agents (including us or any of our affiliates). (See Section 702.)

If any Interest Payment Date, Redemption Date or Maturity of a Bond falls on a day that is not a Business Day, the required payment of principal, premium, if any, and/or interest will be made on the next succeeding Business Day as if made on the date such payment was due, and no interest will accrue on such payment for the period from and after such Interest Payment Date, Redemption Date or Maturity, as the case may be, to the date of such payment on the next succeeding Business Day.

"Business Day" means any day, other than a Saturday or Sunday, that is not a day on which banking institutions or trust companies in The City of New York, New York, or other city in which a paying agent for such Bond is located, are generally authorized or required by law, regulation or executive order to remain closed. (See Section 116.)

Form; Transfers; Exchanges

So long as the Bonds are registered in the name of DTC, as depository for the Bonds as described herein under "— Book-Entry Only Issuance — The Depository Trust Company" or DTC's nominee, transfers and exchanges of beneficial interest in the Bonds will be made as described therein. In the event that the book-entry only system is discontinued, and the Bonds are issued in certificated form, you may exchange or transfer Bonds at the corporate trust office of the Trustee.

You may have your Bonds divided into Bonds of smaller denominations (of at least $2,000 and any larger amount that is an integral multiple of $1,000) or combined into Bonds of larger denominations, as long as the total principal amount is not changed. (See Section 305.)

There will be no service charge for any transfer or exchange of the Bonds, but you may be required to pay a sum sufficient to cover any tax or other governmental charge payable in connection therewith. We may block the transfer or exchange of (1) Bonds during a period of 15 days prior to giving any notice of redemption or (2) any Bond selected for redemption in whole or in part, except the unredeemed portion of any Bond being redeemed in part. (See Section 305.)

The Trustee acts as our agent for registering Bonds in the names of Holders and transferring the Bonds. We may appoint another agent (including one of our affiliates) or act as our own agent for this purpose. The entity performing the role of maintaining the list of registered Holders is called the "Security Registrar." It will also perform transfers. In our discretion, we may change the place for registration of transfer of the Bonds and may designate a different entity as the Security Registrar, including us or one of our affiliates. (See Sections 305 and 702.)

Redemption

We may, at our option, redeem the 2015 Bonds, in whole at any time or in part from time to time, at a redemption price equal to the greater of (1) 100% of the principal amount of the 2015 Bonds to be so redeemed; or
(2)as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the 2015 Bonds to be so redeemed (not including any portion of such payments of interest accrued to the date of redemption) discounted to the Redemption Date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Adjusted Treasury Rate, plus 10 basis points; plus, in either case,
accrued and unpaid interest on the principal amount of the 2015 Bonds to be so redeemed to the Redemption Date.

We may, at our option, redeem the 2020 Bonds, in whole at any time or in part from time to time. If the 2020 Bonds are redeemed before August 1, 2020 (the date that is three months prior to the stated maturity of the 2020 Bonds), the 2020 Bonds will be redeemed by us at a redemption price equal to the greater of (1) 100% of the principal amount of the 2020 Bonds to be so redeemed; or (2) as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the 2020 Bonds to be so redeemed (not including any portion of such payments of interest accrued to the date of redemption) discounted to the Redemption Date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Adjusted Treasury Rate, plus 15 basis points; plus, in either case, accrued and unpaid interest on the principal amount of the 2020 Bonds to be so redeemed to the Redemption Date. If the 2020 Bonds are redeemed on or after August 1, 2020, the 2020 Bonds will be redeemed by us at a redemption price equal to 100% of the principal amount of the 2020 Bonds to be so redeemed, plus accrued and unpaid interest on the principal amount of the 2020 Bonds to be so redeemed to the Redemption Date.

We may, at our option, redeem the 2040 Bonds, in whole at any time or in part from time to time. If the 2040 Bonds are redeemed before May 1, 2040 (the date that is six months prior to the stated maturity of the 2040 Bonds), the 2040 Bonds may be redeemed by us at a redemption price equal to the greater of (1) 100% of the principal amount of the 2040 Bonds to be so redeemed; or (2) as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the 2040 Bonds to be so redeemed (not including any portion of such payments of interest accrued to the date of redemption) discounted to the Redemption Date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Adjusted Treasury Rate, plus 20 basis points; plus, in either case, accrued and unpaid interest on the principal amount of the 2040 Bonds to be so redeemed to the Redemption Date. If the 2040 Bonds are redeemed on or after May 1, 2040, the 2040 Bonds will be redeemed by us at a redemption price equal to 100% of the principal amount of the 2040 Bonds to be so redeemed, plus accrued and unpaid interest on the principal amount of the 2040 Bonds to be so redeemed to the Redemption Date.

"Adjusted Treasury Rate" means, with respect to any Redemption Date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for that Redemption Date.

"Comparable Treasury Issue" means the United States Treasury security selected by the Quotation Agent as having an actual or interpolated maturity comparable to the remaining term of the applicable series of Bonds to be redeemed to the applicable stated maturity date that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such applicable series of Bonds being redeemed.

"Comparable Treasury Price" means, with respect to any Redemption Date:
highest and lowest Reference Treasury Dealer Quotations; or

- the average of five Reference Treasury Dealer Quotations for that Redemption Date, after excluding the

- if the Quotation Agent obtains fewer than five Reference Treasury Dealer Quotations, the average of all of those quotations received.

"Quotation Agent" means one of the Reference Treasury Dealers appointed by us.

"Reference Treasury Dealer" means:

- each of Credit Suisse Securities (USA) LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated and their respective successors, unless any of them ceases to be a primary U.S. Government securities dealer in the United States (a "Primary Treasury Dealer"), in which case we will substitute another Primary Treasury Dealer; and
- any other Primary Treasury Dealers selected by us (after consultation with the Quotation Agent).

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any Redemption Date, the average, as determined by the Quotation Agent, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount), as provided to the Quotation Agent by that Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding that Redemption Date.

The Bonds will not be subject to a sinking fund or other mandatory redemption provisions and will not be repayable at the option of the Holder prior to the applicable stated maturity date.

The Bonds will be redeemable upon notice of redemption to each holder of Bonds to be redeemed by mail between 30 days and 60 days prior to the Redemption Date. If less than all of the Bonds are to be redeemed, the Trustee will select the Bonds or portions thereof to be redeemed. In the absence of any provision for selection, the Trustee will choose a method of random selection that it deems fair and appropriate. (See Sections 503 and 504.)

We may make any redemption at our option conditional upon the receipt by the Paying Agent, on or prior to the date fixed for redemption, of money sufficient to pay the redemption price. If the Paying Agent has not received such money by the date fixed for redemption, we will not be required to redeem such Bonds. (See Section 504.)

If money sufficient to pay the redemption price has been received by the Paying Agent, Bonds called for redemption will cease to bear interest on the Redemption Date. We will pay the redemption price and any accrued interest once you surrender the Bond for redemption. (See Section 505.) If only part of a Bond is redeemed, the Trustee will deliver to you a new Bond of the same series for the remaining portion without charge. (See Section 506.)

We may redeem, in whole or in part, one series of Bonds without redeeming the other series.

Security; Lien of the Mortgage

General

Except as described below under this heading and under "— Issuance of Additional Mortgage Securities," and subject to the exceptions described under "— Satisfaction and Discharge," all Mortgage Securities, including the Bonds, will be secured, equally and ratably, by the lien of the Mortgage, which constitutes, subject to Permitted Liens as described below, a first mortgage lien on substantially all of our real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity (other than property duly released from the lien of the Mortgage in accordance with the provisions thereof and other than Excepted Property, as described below). We sometimes refer to our property that is subject to the lien of the Mortgage as "Mortgaged Property."

We may obtain the release of property from the lien of the Mortgage from time to time, upon the bases provided for such release in the Mortgage. See "— Release of Property."

We may enter into supplemental indentures with the Trustee, without the consent of the Holders, in order to subject additional property (including property that would otherwise be excepted from such lien) to the lien of the Mortgage. (See Section 1401.) This property would constitute Property Additions and would be available as a basis for the issuance of Mortgage Securities. See "— Issuance of Additional Mortgage Securities."

The Mortgage provides that after-acquired property (other than Excepted Property) will be subject to the lien of the Mortgage. (See Granting Clause Second.) However, in the case of consolidation or merger (whether or not we are the surviving company) or transfer of the Mortgaged Property as or substantially as an entirety, the Mortgage will not be required to be a lien upon any of the properties either owned or subsequently acquired by the successor company except properties acquired from us in or as a result of such transfer, as well as improvements, extensions and additions (as defined in the Mortgage) to such properties and renewals, replacements and substitutions of or for any part or parts thereof. See Section 1303 and "— Consolidation, Merger and Conveyance of Assets as an Entirety."

Excepted Property. The lien of the Mortgage does not cover, among other things, the following types of property: property located outside of Kentucky and not specifically subjected or required to be subjected to the lien of the Mortgage; property not used by us in our electric generation, transmission and distribution business; cash and securities not paid, deposited or held under the Mortgage or required so to be; contracts, leases and other agreements of all kinds, contract rights, bills, notes and other instruments, revenues, accounts receivable, claims, demands and judgments; governmental and other licenses, permits, franchises, consents and allowances; intellectual property rights and other general intangibles; vehicles, movable equipment, aircraft and vessels; all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; materials, supplies, inventory and other personal property consumable in the operation of our business; fuel; tools and equipment; furniture and furnishings; computers and data processing, telecommunications and other facilities used primarily for administrative or clerical purposes or otherwise not used in connection with the operation or maintenance of electric generation, transmission and distribution facilities; coal, ore, gas, oil and other minerals and timber rights; electric energy and capacity, gas, steam, water and other products generated, produced, manufactured, purchased or otherwise acquired; real property and facilities used primarily for the production or gathering of natural gas; property which has been released from the lien of the Mortgage; and leasehold interests. We sometimes refer to our property not covered by the lien of the Mortgage as "Excepted Property." (See Granting Clauses.) Properties held by any of our subsidiaries, as well as properties leased from others, would not be subject to the lien of the Mortgage.

Permitted Liens. The lien of the Mortgage is subject to Permitted Liens described in the Mortgage. Such Permitted Liens include liens existing at the execution date of the Mortgage, purchase money liens and other liens placed or otherwise existing on property acquired by us after the execution date of the Mortgage at the time we acquire it, tax liens and other governmental charges which are not delinquent or which are being contested in good faith, mechanics', construction and materialmen's liens, certain judgment liens, easements, reservations and rights of others (including governmental entities) in, and defects of title to, our property, certain leases and leasehold interests, liens to secure public obligations, rights of others to take minerals, timber, electric energy or capacity, gas, water, steam or other products produced by us or by others on our property, rights and interests of Persons other than us arising out of agreements relating to the common ownership or joint use of property, and liens on the interests of such Persons in such property and liens which have been bonded or for which other security arrangements have been made. (See Granting Clauses and Section 101.)

The Mortgage also provides that the Trustee will have a lien, prior to the lien on behalf of the Holders of the Mortgage Securities, upon the Mortgaged Property as security for our payment of its reasonable compensation and expenses and for indemnity against certain liabilities. (See Section 1107.) Any such lien would be a Permitted Lien under the Mortgage.

Issuance of Additional Mortgage Securities

The maximum principal amount of Mortgage Securities that may be authenticated and delivered under the Mortgage is subject to the issuance restrictions described below; provided, however, that the maximum principal amount of Mortgage Securities outstanding at any one time shall not exceed One Quintillion Dollars ($1,000,000,000,000,000,000), which amount may be changed by supplemental indenture. (See Section 301.) Mortgage Securities of any series may be issued from time to time on the basis of, and in an aggregate principal amount not exceeding:

- 66⅔% of the Cost or Fair Value to the Company (whichever is less) of Property Additions (as described below) which do not constitute Funded Property (generally, Property Additions which have been made the basis of the authentication and delivery of Mortgage Securities, the release of Mortgaged Property or the withdrawal of cash, which have been substituted for retired Funded Property or which have been used for other specified purposes) after certain deductions and additions, primarily including adjustments to offset property retirements;

- the aggregate principal amount of Retired Securities (as described below); or
- an amount of cash deposited with the Trustee. (See Article Four.)

Property Additions generally include any property which is owned by us and is subject to the lien of the Mortgage except (with certain exceptions) goodwill, going concern value rights or intangible property, or any property the acquisition or construction of which is properly chargeable to one of our operating expense accounts in accordance with U.S. generally accepted accounting principles. (See Section 104.)

Retired Securities means, generally, Mortgage Securities which are no longer outstanding under the Mortgage, which have not been retired by the application of Funded Cash and which have not been used as the basis for the authentication and delivery of Mortgage Securities, the release of property or the withdrawal of cash.

We intend to issue the Bonds on the basis of Property Additions. At November 1, 2010, approximately $3.384 billion of Property Additions were available to us to be used as the basis for the authentication and delivery of Mortgage Securities (including the Bonds offered hereby). (See Article Four)

Release of Property

Unless an Event of Default has occurred and is continuing, we may obtain the release from the lien of the Mortgage of any Mortgaged Property, except for cash held by the Trustee, upon delivery to the Trustee of an amount in cash equal to the amount, if any, by which sixty-six and two-thirds percent (66⅔%) of the Cost of the property to be released (or, if less, the Fair Value to us of such property at the time it became Funded Property) exceeds the aggregate of:

- an amount equal to 66⅔% of the aggregate principal amount of obligations secured by Purchase Money Liens upon the property to be released and delivered to the Trustee;
- an amount equal to 66⅔% of the Cost or Fair Value to us (whichever is less) of certified Property Additions not constituting Funded Property after certain deductions and additions, primarily including adjustments to offset property retirements (except that such adjustments need not be made if such Property Additions were acquired or made within the 90-day period preceding the release);
- the aggregate principal amount of Mortgage Securities we would be entitled to issue on the basis of Retired Securities (with such entitlement being waived by operation of such release);
- the aggregate principal amount of Mortgage Securities delivered to the Trustee (with such Mortgage Securities to be canceled by the Trustee);
- any amount of cash and/or an amount equal to 66⅔% of the aggregate principal amount of obligations secured by Purchase Money Liens upon the property released delivered to the trustee or other holder of a lien prior to the lien of the Mortgage, subject to certain limitations described in the Mortgage; and
- any taxes and expenses incidental to any sale, exchange, dedication or other disposition of the property to be released.

(See Section 803.)

As used in the Mortgage, the term “Purchase Money Lien” means, generally, a lien on the property being released which is retained by the transferor of such property or granted to one or more other Persons in connection with the transfer or release thereof, or granted to or held by a trustee or agent for any such Persons, and may include liens which cover property in addition to the property being released and/or which secure indebtedness in addition to indebtedness to the transferor of such property (See Section 101.).

Unless an Event of Default has occurred and is continuing, property which is not Funded Property may generally be released from the lien of the Mortgage without depositing any cash or property with the Trustee as long as (a) the aggregate amount of Cost or Fair Value to us (whichever is less) of all Property Additions which do not constitute Funded Property (excluding the property to be released) after certain deductions and additions, primarily including adjustments to offset property retirements, is not less than zero or (b) the Cost or Fair Value (whichever is less) of property to be released does not exceed the aggregate amount of the Cost or Fair Value to us (whichever is less) of Property Additions acquired or made within the 90-day period preceding the release. (See Section 804.)

The Mortgage provides simplified procedures for the release of minor properties and property taken by eminent domain, and provides for dispositions of certain obsolete property and grants or surrender of certain rights without any release or consent by the Trustee. (See Sections 805, 807 and 808.)

If we retain any interest in any property released from the lien of the Mortgage, the Mortgage will not become a lien on such property or such interest therein or any improvements, extensions or additions to such property or renewals, replacements or substitutions of or for such property or any part or parts thereof. (See Section 809.)

Withdrawal of Cash

Unless an Event of Default has occurred and is continuing, and subject to certain limitations, cash held by the Trustee may, generally, (1) be withdrawn by us (a) to the extent of sixty-six and two-thirds percent (66⅔%) of the Cost or Fair Value to us (whichever is less) of Property Additions not constituting Funded Property, after certain deductions and additions, primarily including adjustments to offset retirements (except that such adjustments need not be made if such Property Additions were acquired or made within the 90-day period preceding the withdrawal) or (b) in an amount equal to the aggregate principal amount of Mortgage Securities that we would be entitled to issue on the basis of Retired Securities (with the entitlement to such issuance being waived by operation of such withdrawal) or (c) in an amount equal to the aggregate principal amount of any outstanding Mortgage Securities delivered to the Trustee; or (2) upon our request, be applied to (a) the purchase of Mortgage Securities in a manner and at a price approved by us or (b) the payment (or provision for payment) at stated maturity of any Mortgage Securities or the redemption (or provision for payment) of any Mortgage Securities which are redeemable (see Section 806); provided, however, that cash deposited with the Trustee as the basis for the authentication and delivery of Mortgage Securities may, in addition, be withdrawn in an amount not exceeding the aggregate principal amount of cash delivered to the Trustee for such purpose. (See Section 404.)

Events of Default

An "Event of Default" occurs under the Mortgage if

- we do not pay any interest on any Mortgage Securities within 30 days of the due date;
- we do not pay principal or premium, if any, on any Mortgage Securities on the due date;
- we remain in breach of any other covenant (excluding covenants specifically dealt with elsewhere in this section) in respect of any Mortgage Securities for 90 days after we receive a written notice of default stating we are in breach and requiring remedy of the breach; the notice must be sent by either the Trustee or Holders of 25% of the principal amount of outstanding Mortgage Securities; the Trustee or such Holders can agree to extend the 90-day period and such an agreement to extend will be automatically deemed to occur if we initiate corrective action within such 90-day period and we are diligently pursuing such action to correct the default; or
- we file for bankruptcy or certain other events in bankruptcy, insolvency, receivership or reorganization occur.

(See Section 1001.)

Remedies

Acceleration of Maturity

If an Event of Default occurs and is continuing, then either the Trustee or the Holders of not less than 25% in principal amount of the outstanding Mortgage Securities may declare the principal amount of all of the Mortgage Securities to be due and payable immediately. (See Section 1002.)

Rescission of Acceleration

After the declaration of acceleration has been made and before the Trustee has obtained a judgment or decree for payment of the money due, such declaration and its consequences will be rescinded and annulled, if

(i) we pay or deposit with the Trustee a sum sufficient to pay:

- all overdue interest;
- the principal of and premium, if any, which have become due otherwise than by such declaration of acceleration and interest thereon;
- interest on overdue interest to the extent lawful; and
- all amounts due to the Trustee under the Mortgage; and

(ii) all Events of Default, other than the nonpayment of the principal which has become due solely by such declaration of acceleration, have been cured or waived as provided in the Mortgage.

(See Section 1002.)

For more information as to waiver of defaults, see "— Waiver of Default and of Compliance" below.

Appointment of Receiver and Other Remedies

Subject to the Mortgage, under certain circumstances and to the extent permitted by law, if an Event of Default occurs and is continuing, the Trustee has the power to appoint a receiver of the Mortgaged Property, and is entitled to all other remedies available to mortgagees and secured parties under the Uniform Commercial Code or any other applicable law. (See Section 1016.)

Control by Holders; Limitations

Subject to the Mortgage, if an Event of Default occurs and is continuing, the Holders of a majority in principal amount of the outstanding Mortgage Securities will have the right to

- direct the time, method and place of conducting any proceeding for any remedy available to the Trustee, or
- exercise any trust or power conferred on the Trustee.

The rights of Holders to make direction are subject to the following limitations:

- the Holders' directions may not conflict with any law or the Mortgage; and
- the Holders' directions may not involve the Trustee in personal liability where the Trustee believes indemnity is not adequate.

The Trustee may also take any other action it deems proper which is not inconsistent with the Holders' direction. (See Sections 1012 and 1103.)

In addition, the Mortgage provides that no Holder of any Mortgage Security will have any right to institute any proceeding, judicial or otherwise, with respect to the Mortgage for the appointment of a receiver or for any other remedy thereunder unless

- that Holder has previously given the Trustee written notice of a continuing Event of Default;
- the Holders of 25% in aggregate principal amount of the outstanding Mortgage Securities have made written request to the Trustee to institute proceedings in respect of that Event of Default and have offered the Trustee reasonable indemnity against costs, expenses and liabilities incurred in complying with such request; and
- for 60 days after receipt of such notice, request and offer of indemnity, the Trustee has failed to institute any such proceeding and no direction inconsistent with such request has been given to the Trustee during such 60-day period by the Holders of a majority in aggregate principal amount of outstanding Mortgage Securities.

Furthermore, no Holder will be entitled to institute any such action if and to the extent that such action would disturb or prejudice the rights of other Holders. (See Sections 1007 and 1103.)

However, each Holder has an absolute and unconditional right to receive payment when due and to bring a suit to enforce that right. (See Section 1008.)

Notice of Default

The Trustee is required to give the Holders of the Mortgage Securities notice of any default under the Mortgage to the extent required by the Trust Indenture Act, unless such default has been cured or waived; except that in the case of an Event of Default of the character specified in the third bullet point under "— Events of Default" (regarding a breach of certain covenants continuing for 90 days after the receipt of a written notice of default), no such notice shall be given to such Holders until at least 60 days after the occurrence thereof. (See Section 1102.) The Trust Indenture Act currently permits the Trustee to withhold notices of default (except for certain payment defaults) if the Trustee in good faith determines the withholding of such notice to be in the interests of the Holders.

We will furnish the Trustee with an annual statement as to our compliance with the conditions and covenants in the Mortgage. (See Section 709.)

Waiver of Default and of Compliance

The Holders of a majority in aggregate principal amount of the outstanding Mortgage Securities may waive, on behalf of the Holders of all outstanding Mortgage Securities, any past default under the Mortgage, except a default in the payment of principal, premium or interest, or with respect to compliance with certain provisions of the Mortgage that cannot be amended without the consent of the Holder of each outstanding Mortgage Security affected. (See Section 1013.)

Compliance with certain covenants in the Mortgage or otherwise provided with respect to Mortgage Securities may be waived by the Holders of a majority in aggregate principal amount of the affected Mortgage Securities, considered as one class. (See Section 710.)

Consolidation, Merger and Conveyance of Assets as an Entirety

Subject to the provisions described below, we have agreed to preserve our corporate existence. (See Section 704.)

We have agreed not to consolidate with or merge with or into any other entity or convey, transfer or lease the Mortgaged Property as or substantially as an entirety to any entity unless

- the entity formed by such consolidation or into which we merge, or the entity which acquires or which leases the Mortgaged Property substantially as an entirety, is an entity organized and existing under the laws of the United States of America or any State or Territory thereof or the District of Columbia, and
  - expressly assumes, by supplemental indenture, the due and punctual payment of the principal of, and premium and interest on, all the outstanding Mortgage Securities and the performance of all of our covenants under the Mortgage, and
  - such entity confirms the lien of the Mortgage on the Mortgaged Property;
- in the case of a lease, such lease is made expressly subject to termination by (i) us or by the Trustee and (ii) the purchaser of the property so leased at any sale thereof, at any time during the continuance of an Event of Default; and
- immediately after giving effect to such transaction, no Event of Default, and no event which after notice or lapse of time or both would become an Event of Default, will have occurred and be continuing.

(See Section 1301.)

In the case of the conveyance or other transfer of the Mortgaged Property as or substantially as an entirety to any other person, upon the satisfaction of all the conditions described above we would be released and discharged from all obligations under the Mortgage and on the Mortgage Securities then outstanding unless we elect to waive such release and discharge. (See Section 1304.)

The Mortgage does not prevent or restrict:

- any consolidation or merger after the consummation of which we would be the surviving or resulting entity; or
- any conveyance or other transfer, or lease, of any part of the Mortgaged Property which does not constitute the entirety or substantially the entirety thereof.

If following a conveyance or other transfer, or lease, of any part of the Mortgaged Property, the fair value of the Mortgaged Property retained by the Company exceeds an amount equal to three-halves (3/2) of the aggregate principal amount of all outstanding Mortgage Securities, then the part of the Mortgaged Property so conveyed, transferred or leased shall be deemed not to constitute the entirety or substantially the entirety of the Mortgaged Property. This fair value will be determined within 90 days of the conveyance or transfer by an independent expert that we select and that is approved by the Trustee.

(See Sections 1305 and 1306.)

Agreement to Provide Information

So long as any Bonds are outstanding under the Mortgage, during such periods as we are not subject to the periodic reporting requirements of Section 13 or 15(d) of the Exchange Act, we shall make available to Holders of the Bonds by means of posting on our website or other similar means:

(a) as soon as reasonably available and in any event within 120 days after the end of each fiscal year, our audited balance sheet, income statement and cash flow statement for such fiscal year prepared in accordance with United States generally accepted accounting principles (with notes to such financial statements), together with an audit report thereon by an independent accounting firm of established national reputation, and a management’s narrative analysis of the results of operations explaining the reasons for material changes in the amount of revenue and expense items between the most recent fiscal year presented and the fiscal year immediately preceding it, as described in Instruction I(2)(a) of Form 10-K; and

(b) as soon as reasonably available and in any event within 60 days after the end of each of the first three fiscal quarters of each fiscal year, our unaudited balance sheet, unaudited income statement and unaudited cash flow statement for such fiscal quarter prepared in accordance with United States generally accepted accounting principles (with notes to such financial statements) and a management’s narrative analysis of the results of operations explaining the reasons for material changes in the amount of revenue and expense items between the most recent fiscal year-to-date period presented and the corresponding year-to-date period in the preceding fiscal year, as described in Instruction H(2)(a) to Form 10-Q.

If we are unable, for any reason, to post the financial statements on our website, we shall furnish the financial statements to the Trustee, who, at our expense, will furnish them to the Holders of the Bonds. In addition, for so long as any Bonds remain outstanding, we will furnish to prospective purchasers of the Bonds, upon their request, the information described above as well as any other information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act for compliance with Rule 144A.

Modification of Mortgage

Without Holder Consent. Without the consent of any Holders of Mortgage Securities, we and the Trustee may enter into one or more supplemental indentures for any of the following purposes:

- to evidence the succession of another entity to us;
- to add one or more covenants or other provisions for the benefit of the Holders of all or any series or tranche of Mortgage Securities, or to surrender any right or power conferred upon us;

- to correct or amplify the description of any property at any time subject to the lien of the Mortgage; or to better to assure, convey and confirm unto the Trustee any property subject or required to be subjected to the lien of the Mortgage; or to subject to the lien of the Mortgage additional property (including property of others), to specify any additional Permitted Liens with respect to such additional property and to modify the provisions in the Mortgage for dispositions of certain types of property without release in order to specify any additional items with respect to such additional property;
- to add any additional Events of Default, which may be stated to remain in effect only so long as the Mortgage Securities of any one more particular series remains outstanding;
- to change or eliminate any provision of the Mortgage or to add any new provision to the Mortgage that does not adversely affect the interests of the Holders in any material respect;
- to establish the form or terms of any series or tranche of Mortgage Securities;
- to provide for the issuance of bearer securities;
- to evidence and provide for the acceptance of appointment of a successor Trustee or by a co-trustee or separate trustee;
- to provide for the procedures required to permit the utilization of a noncertificated system of registration for any series or tranche of Mortgage Securities;
- to change any place or places where
  - we may pay principal, premium and interest,
  - Mortgage Securities may be surrendered for transfer or exchange, and
  - notices and demands to or upon us may be served;
- to amend and restate the Mortgage as originally executed, and as amended from time to time, with such additions, deletions and other changes that do not adversely affect the interest of the Holders in any material respect;
- to cure any ambiguity, defect or inconsistency or to make any other changes that do not adversely affect the interests of the Holders in any material respect; or
- to increase or decrease the maximum principal amount of Mortgage Securities that may be outstanding at any time.

In addition, if the Trust Indenture Act is amended after the date of the Mortgage so as to require changes to the Mortgage or so as to permit changes to, or the elimination of, provisions which, at the date of the Mortgage or at any time thereafter, were required by the Trust Indenture Act to be contained in the Mortgage, the Mortgage will be deemed to have been amended so as to conform to such amendment or to effect such changes or elimination, and we and the Trustee may, without the consent of any Holders, enter into one or more supplemental indentures to effect or evidence such amendment.

(See Section 1401.)

With Holder Consent. Except as provided above, the consent of the Holders of at least a majority in aggregate principal amount of the Mortgage Securities of all outstanding series, considered as one class, is generally required for the purpose of adding to, or changing or eliminating any of the provisions of, the Mortgage pursuant to a supplemental indenture. However, if less than all of the series of outstanding Mortgage Securities are directly affected by a proposed supplemental indenture, then such proposal only requires the consent of the Holders of a majority in aggregate principal amount of the outstanding Mortgage Securities of all directly affected series, considered as one class. Moreover, if the Mortgage Securities of any series have been issued in more than one tranche and if the proposed supplemental indenture directly affects the rights of the Holders of Mortgage Securities of one or more, but less than all, of such tranches, then such proposal only requires the consent of the Holders of a majority in aggregate principal amount of the outstanding Mortgage Securities of all directly affected tranches,
considered as one class.

However, no amendment or modification may, without the consent of the Holder of each outstanding Mortgage Security directly affected thereby,

- change the stated maturity of the principal or interest on any Mortgage Security (other than pursuant to the terms thereof), or reduce the principal amount, interest or premium payable (or the method of calculating such rates) or change the currency in which any Mortgage Security is payable, or impair the right to bring suit to enforce any payment;
- create any lien (not otherwise permitted by the Mortgage) ranking prior to the lien of the Mortgage with respect to all or substantially all of the Mortgaged Property, or terminate the lien of the Mortgage on all or substantially all of the Mortgaged Property (other than in accordance with the terms of the Mortgage), or deprive any Holder of the benefits of the security of the lien of the Mortgage;
- reduce the percentages of Holders whose consent is required for any supplemental indenture or waiver of compliance with any provision of the Mortgage or of any default thereunder and its consequences, or reduce the requirements for quorum and voting under the Mortgage; or
- modify certain of the provisions of the Mortgage relating to supplemental indentures, waivers of certain covenants and waivers of past defaults with respect to Mortgage Securities.

A supplemental indenture which changes, modifies or eliminates any provision of the Mortgage expressly included solely for the benefit of Holders of Mortgage Securities of one or more particular series or tranches will be deemed not to affect the rights under the Mortgage of the Holders of Mortgage Securities of any other series or tranche.

(See Section 1402.)

Satisfaction and Discharge

Any Mortgage Securities or any portion thereof will be deemed to have been paid and no longer outstanding for purposes of the Mortgage and, at our election, our entire indebtedness with respect to those securities will be satisfied and discharged, if there shall have been irrevocably deposited with the Trustee or any Paying Agent (other than the Company), in trust:

- money sufficient, or
- in the case of a deposit made prior to the maturity of such Mortgage Securities, non-redeemable Eligible Obligations (as defined in the Mortgage) sufficient, or
- a combination of the items listed in the preceding two bullet points, which in total are sufficient,

to pay when due the principal of, and any premium, and interest due and to become due on such Mortgage Securities or portions of such Mortgage Securities on and prior to their maturity.

(See Section 901.)

Our right to cause our entire indebtedness in respect of the Mortgage Securities of any series to be deemed to be satisfied and discharged as described above will be subject to the satisfaction of any conditions specified in the instrument creating such series.

The Mortgage will be deemed satisfied and discharged when no Mortgage Securities remain outstanding and when we have paid all other sums payable by us under the Mortgage. (See Section 902.)

All moneys we pay to the Trustee or any Paying Agent on Bonds that remain unclaimed at the end of two years after payments have become due may be paid to or upon our order. Thereafter, the Holder of such Bond may look only to us for payment. (See Section 703.)

Duties of the Trustee; Resignation and Removal of the Trustee; Deemed Resignation

The Trustee will have, and will be subject to, all the duties and responsibilities specified with respect to an indenture trustee under the Trust Indenture Act. Subject to these provisions, the Trustee will be under no obligation to exercise any of the powers vested in it by the Mortgage at the request of any holder of Mortgage Securities, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred thereby. The Trustee will not be required to expend or risk its own funds or otherwise incur financial liability in the performance of its duties if the Trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

The Trustee may resign at any time by giving written notice to us.

The Trustee may also be removed by act of the Holders of a majority in principal amount of the then outstanding Mortgage Securities of any series.

No resignation or removal of the Trustee and no appointment of a successor trustee will become effective until the acceptance of appointment by a successor trustee in accordance with the requirements of the Mortgage.

Under certain circumstances, we may appoint a successor trustee and if the successor accepts, the Trustee will be deemed to have resigned.

(See Section 1110.)

Evidence to be Furnished to the Trustee

Compliance with Mortgage provisions is evidenced by written statements of our officers or persons selected or paid by us. In certain cases, opinions of counsel and certifications of an engineer, accountant, appraiser or other expert (who in some cases must be independent) must be furnished. In addition, the Mortgage requires us to give to the Trustee, not less than annually, a brief statement as to our compliance with the conditions and covenants under the Mortgage.

Miscellaneous Provisions

The Mortgage provides that certain Mortgage Securities, including those for which payment or redemption money has been deposited or set aside in trust as described under "— Satisfaction and Discharge" above, will not be deemed to be "outstanding" in determining whether the Holders of the requisite principal amount of the outstanding Mortgage Securities have given or taken any demand, direction, consent or other action under the Mortgage as of any date, or are present at a meeting of Holders for quorum purposes. (See Section 101.)

We will be entitled to set any day as a record date for the purpose of determining the Holders of outstanding Mortgage Securities of any series entitled to give or take any demand, direction, consent or other action under the Mortgage, in the manner and subject to the limitations provided in the Mortgage. In certain circumstances, the Trustee also will be entitled to set a record date for action by Holders. If such a record date is set for any action to be taken by Holders of particular Mortgage Securities, such action may be taken only by persons who are Holders of such Mortgage Securities on the record date. (See Section 107.)

Governing Law

The Mortgage and the Mortgage Securities provide that they are to be governed by and construed in accordance with the laws of the State of New York except where the Trust Indenture Act is applicable or where otherwise required by law. (See Section 115.) The effectiveness of the lien of the Mortgage, and the perfection and priority thereof, will be governed by Kentucky law.

Regarding the Trustee

The Trustee under the Mortgage is the Bank of New York Mellon ("BNYM"). In addition to acting as Trustee, BNYM also maintains various banking and trust relationships with us and some of our affiliates.

Book-Entry Only Issuance — The Depository Trust Company

DTC will act as the initial securities depository for the Bonds. The Bonds will be issued as fully-registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered certificate will be issued with respect to each $500 million of principal amount of Bonds, and an additional certificate will be issued with respect to any remaining principal amount of Bonds. The global bonds will be deposited with the Trustee as custodian for DTC.

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Exchange Act. DTC holds securities for its participants ("Direct Participants") and also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts, thereby eliminating the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). The rules that apply to DTC and those using its system are on file with the SEC. More information about DTC can be found at www.dtcc.com.

Purchases of the Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchases, but Beneficial Owners should receive written confirmations providing details of the transactions, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which they purchased Bonds. Transfers of ownership interests on the Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in Bonds, except in the event that use of the book-entry system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of the Bonds with DTC and their registration in the name of Cede & Co. or such other nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts the Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners, will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Notices will be sent to DTC.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's procedures. Under its usual procedures, DTC mails an omnibus proxy to us as soon as possible after the record date. The omnibus proxy assigns the voting or consenting rights of Cede & Co. to those Direct Participants to whose accounts the Bonds are credited on the record date. We believe that these arrangements will enable the beneficial owners to exercise rights equivalent in substance to the rights that can be directly exercised by a registered Holder of the Bonds.

Payments of principal and interest on the Bonds will be made to Cede & Co. (or such other nominee of DTC). DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from us or the Trustee, on payable date in accordance with their respective holdings shown on DTC's records. Payments by participants to Beneficial Owners will be governed by standing instructions and customary practices and will be the responsibility of such participant and not of DTC, the Trustee or us, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of the Purchase Price, principal and interest to Cede & Co. (or such other nominee of DTC) is the responsibility of us or the Trustee. Disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners is the responsibility of Direct and Indirect Participants.

A beneficial owner will not be entitled to receive physical delivery of the Bonds. Accordingly, each beneficial owner must rely on the procedures of DTC to exercise any rights under the Bonds.

DTC may discontinue providing its services as securities depository with respect to the Bonds at any time by giving us or the Trustee reasonable notice. In the event no successor securities depository is obtained, certificates for the Bonds will be printed and delivered.

The information in this section concerning DTC and DTC's book-entry system has been obtained from sources that we believe to be reliable, but neither we nor the initial purchasers take any responsibility for the accuracy of this information.

Transfers of Beneficial Interests between U.S. Global Bond and Offshore Global Bond

A beneficial interest in the U.S. global bond may be transferred to a person who wishes to hold such beneficial interest through the offshore global bond only upon receipt by the trustee of a written certification of the transferor to the effect that such transfer is being made in compliance with Regulation S under the Securities Act.

A beneficial interest in the offshore global bond may be transferred to a person who wishes to hold such beneficial interest through the U.S. global bond only upon receipt by the trustee of a written certification of the transferee to the effect that such transferee is a qualified institutional buyer within the meaning of Rule 144A under the Securities Act in a transaction meeting the requirements of Rule 144A.

The restrictions on transfer described in the preceding two paragraphs will not apply to (1) bonds sold pursuant to a registration statement under the Securities Act or to Exchange Bonds (as discussed under "Registration Rights Agreement") or (2) after such time (if any) as the Company determines and instructs the trustee that the bonds are eligible for resale pursuant to Rule 144 under the Securities Act without the need for current public information. There is no assurance that the bonds will become eligible for resale pursuant to Rule 144.

Any beneficial interest in one global bond that is transferred to a person who takes delivery in the form of an interest in another global bond will, upon transfer, cease to be an interest in such global bond and become an interest in the other global bond and, accordingly, will thereafter be subject to all transfer restrictions applicable to beneficial interests in such other global note for as long as it remains such an interest.

REGISTRATION RIGHTS AGREEMENT

Registered Exchange Offer

We will enter into a registration rights agreement with the initial purchasers on or before the issue date of the Bonds. The following is a description of certain provisions of the registration rights agreement. We urge you to read the form of registration rights agreement in its entirety because it, and not this description, defines your registration rights as a holder of the Bonds. Under the registration rights agreement, we will, at our own cost:

- file with the SEC a registration statement (an "Exchange Offer Registration Statement") with respect to a registered offer (the "Registered Exchange Offer") to exchange the Bonds for new bonds of the Company (the "Exchange Bonds") having terms substantially identical in all material respects to the Bonds (except that the Exchange Bonds will not contain terms with respect to transfer restrictions) within 180 days of the closing of this offering of the Bonds;
- use our commercially reasonable efforts to cause the Exchange Offer Registration Statement to be declared effective under the Securities Act not later than 270 days of the closing of this offering of the Bonds (or if such day is not a business day, the first business day thereafter);
- upon the effectiveness of the Exchange Offer Registration Statement, promptly offer the Exchange Bonds in exchange for the surrender of the Bonds; and
- keep the Registered Exchange Offer open for not less than 20 business days (or longer if required by applicable law) after the date notice of the Registered Exchange Offer is mailed to the holders of the Bonds.

For each Bond validly tendered to us and not withdrawn pursuant to the Registered Exchange Offer, we will issue to the holder of such Bond an Exchange Bond having a principal amount equal to that of the surrendered Bond. Interest on each Exchange Bond will accrue from the last interest payment date on which interest was paid on the Bond surrendered in exchange therefor.

Under existing SEC interpretations, the Exchange Bonds would be freely transferable by holders other than our affiliates after the Registered Exchange Offer without further registration under the Securities Act if the holder of the Exchange Bonds represents that it is acquiring the Exchange Bonds in the ordinary course of its business, that it has no arrangement or understanding with any person to participate in the distribution of the Exchange Bonds and that it is not an affiliate of ours, as such terms are defined under the Securities Act or interpreted by the SEC; provided, however, that broker-dealers ("Participating Broker-Dealers") receiving Exchange Bonds in the Reg- istered Exchange Offer will have a prospectus delivery requirement with respect to resales of such Exchange Bonds. The SEC has taken the position that Participating Broker-Dealers may fulfill their prospectus delivery requirements with respect to Exchange Bonds (other than a resale of an unsold allotment from the original sale of the Bonds) with the prospectus contained in the Exchange Offer Registration Statement.

Under the registration rights agreement, we are required to allow Participating Broker-Dealers and other persons, if any, with similar prospectus delivery requirements to use the prospectus contained in the Exchange Offer Registration Statement in connection with the resale of such Exchange Bonds.

A holder of Bonds that wishes to exchange such Bonds for Exchange Bonds in the Registered Exchange Offer will be required to represent that (1) any Exchange Bonds to be received by it will be acquired in the ordinary course of its business, (2) it has no arrangement with any person to participate in the distribution (within the meaning of the Securities Act) of the Bonds or the Exchange Bonds, (3) it is not an "affiliate" of ours, as defined in Rule 405 of the Securities Act, or if it is an affiliate, that it will comply with the registration and prospectus delivery requirements of the Securities Act to the extent applicable, (4) if such holder is not a broker-dealer, that it is not engaged in, and does not intend to engage in, the distribution of the Exchange Bonds, and (5) if such holder is a broker-dealer, that it will receive Exchange Bonds for its own account in exchange for Bonds that were acquired as a result of market-making activities or other trading activities and that it will be required to acknowledge that it will deliver a prospectus in connection with any resale of such Exchange Bonds.

Shelf Registration Statement

If (1) a change in law or in applicable interpretations of the staff of the SEC does not permit us to effect such a Registered Exchange Offer, (2) for any other reason the Registered Exchange Offer is not consummated within

315 days of the closing of this offering of the Bonds, (3) any initial purchaser so requests with respect to Bonds not eligible to be exchanged for Exchange Bonds in the Registered Exchange Offer and held by it following consummation of the Registered Exchange Offer, or (4) any holder notifies us during the 20 business days following consummation of the Registered Exchange Offer that it was not eligible to participate in the Registered Exchange Offer or any holder who participates in the Registered Exchange Offer does not receive freely tradeable Exchange Bonds in the Registered Exchange Offer, and such holder so requests, we will at our cost:

- file with the SEC a shelf registration statement (a "Shelf Registration Statement") under the Securities Act covering continuous resales of the Bonds or Exchange Bonds, as the case may be;
- use our commercially reasonable efforts to cause such Shelf Registration Statement to be declared effective under the Securities Act within the later of (i) 180 days after being required or requested to file a Shelf Registration Statement and (ii) 270 days after the closing of this offering of the Bonds; and
- use our commercially reasonable efforts to keep the Shelf Registration Statement effective until the earlier of (a)one year from the issue date of the Bonds, (b) when all Bonds covered by the Shelf Registration Statement have been sold, (c) when all Bonds covered by the Shelf Registration Statement are distributed to the public pursuant to Rule 144, or are saleable pursuant to Rule 144, or are otherwise no longer restricted securities (as defined in Rule 144) and (d) when all Bonds covered by the Shelf Registration Statement cease to be outstanding.

We will, in the event a Shelf Registration Statement is declared effective, among other things, provide to each holder for whom such Shelf Registration Statement was filed copies of the prospectus which is a part of the Shelf Registration Statement, notify each such holder when the Shelf Registration Statement has become effective and take certain other actions as are required to permit unrestricted resales of the Bonds or the Exchange Bonds, as the case may be. A holder selling such Bonds or Exchange Bonds pursuant to the Shelf Registration Statement generally would be required to be named as a selling security holder in the related prospectus and to deliver a prospectus to purchasers, will be subject to certain of the civil liability provisions under the Securities Act in connection with such sales and will be bound by the provisions of the registration rights agreement that are applicable to such holder (including certain indemnification obligations).

Liquidated Damages

We will pay liquidated damages in cash if:

- neither the Exchange Offer Registration Statement nor a Shelf Registration Statement (if required) is filed by us in the applicable time periods specified above; or
- neither the Exchange Offer Registration Statement nor a Shelf Registration Statement (if required) is declared effective by the SEC within the applicable time periods specified above; or
- the Registered Exchange Offer is not consummated within 315 days after the closing of this offering of the Bonds (or if the 315th day is not a business day, by the first business day thereafter); or
- after the Exchange Offer Registration Statement or the Shelf Registration Statement, as the case may be, is declared effective, such Registration Statement thereafter ceases to be effective or usable (subject to certain exceptions) in connection with resales of Bonds or Exchange Bonds as provided in and during the periods specified in the Registration Rights Agreement (each such event referred to in the first through fourth bullet points, a Registration Default).

Liquidated damages will be payable at a rate of 0.25% per annum for the first 90 days from and including the date on which any Registration Default occurs, and such Liquidated Damages rate shall increase by an additional 0.25% per annum thereafter; provided, however, that the Liquidated Damages rate on the Bonds shall not at any time exceed 0.50% per annum. Liquidated damages shall cease to accrue on and after the date on which all Registration Defaults have been cured. Such liquidated damages will be payable on interest payment dates in addition to interest payable from time to time on the Bonds and Exchange Bonds.

TRANSFER RESTRICTIONS

The Bonds have not been registered under the Securities Act and may not be offered or sold within the United States or to, or for the account or benefit of, U.S. persons (as defined in Regulation S under the Securities Act) except to (a) qualified institutional buyers in reliance on the exemption from the registration requirements of the Securities Act provided by Rule 144A and (b) persons in offshore transactions in reliance on Regulation S.

Each purchaser of Bonds will be deemed to have represented and agreed as follows (terms used in this paragraph that are defined in Rule 144A or Regulation S under the Securities Act are used herein as defined therein):

(1) The purchaser (A) (i) is a qualified institutional buyer, (ii) is aware that the sale to it is being made in reliance on Rule 144A and (iii) is acquiring the Bonds for its own account or for the account of a qualified institutional buyer or (B) is not a U.S. person and is purchasing the Bonds in an offshore transaction pursuant to Regulation S.

(2) The purchaser understands that the Bonds are being offered in a transaction not involving any public offering in the United States within the meaning of the Securities Act, that the Bonds have not been and except as described in this offering circular, will not be registered under the Securities Act and that (A) if in the future it decides to offer, resell, pledge or otherwise transfer any of the Bonds, such Bonds may be offered, resold, pledged or otherwise transferred only (i) in the United States to a person whom the seller reasonably believes is a qualified institutional buyer in a transaction meeting the requirements of Rule 144A, (ii) outside the United States in a transaction complying with the provisions of Regulation S under the Securities Act, (iii)pursuant to an exemption from registration under the Securities Act provided by Rule 144 (if available) or any other such exemption, or (iv) pursuant to an effective registration statement under the Securities Act, in each of cases (i) through (iv) in accordance with any applicable securities laws of any State of the United States, and that (B) the purchaser will, and each subsequent holder is required to, notify any subsequent purchaser of the Bonds from it of the resale restrictions referred to in (A) above.

(3) The purchaser understands that the Bonds will, until the expiration of the applicable holding period with respect to the Bonds set forth in Rule 144(d) of the Securities Act, unless otherwise agreed by the Issuer and the holder thereof, bear a legend substantially to the following effect:

> THIS BOND HAS NOT BEEN REGISTERED UNDER THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE “SECURITIES ACT”), AND NEITHER THIS BOND NOR ANY INTEREST HEREIN MAY BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED EXCEPT
>
> (A) TO A “QUALIFIED INSTITUTIONAL BUYER” IN COMPLIANCE WITH RULE 144A UNDER THE SECURITIES ACT,
>
> (B) IN AN “OFFSHORE TRANSACTION” IN COMPLIANCE WITH REGULATION S UNDER THE SECURITIES ACT,
>
> (C) PURSUANT TO AN EXEMPTION FROM REGISTRATION PROVIDED BY RULE 144 UNDER THE SECURITIES ACT OR ANY OTHER AVAILABLE EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE SECURITIES ACT, OR
>
> (D) PURSUANT TO A REGISTRATION STATEMENT WHICH HAS BECOME EFFECTIVE UNDER THE SECURITIES ACT.
>
> THE OWNER OF THIS BOND, AND THE OWNER OF EACH INTEREST HEREIN, BY ITS ACQUISITION HEREOF OR THEREOF, REPRESENTS THAT ITS ACQUISITION OF THIS BOND OR SUCH INTEREST IS DESCRIBED IN ONE OF CLAUSES (A), (B), (C) OR (D) IN THE FIRST PARAGRAPH OF THIS LEGEND AND AGREES THAT ANY DISPOSITION BY IT OF THIS BOND OR SUCH INTEREST HEREIN WILL BE DESCRIBED IN ONE OF SUCH CLAUSES.
>
> PRIOR TO THE REGISTRATION OF ANY TRANSFER IN ACCORDANCE WITH CLAUSE (A) OR (B) ABOVE, A DULY COMPLETED AND SIGNED CERTIFICATE (THE FORM OF WHICH MAY BE OBTAINED FROM THE TRUSTEE) MUST BE DELIVERED TO THE TRUSTEE. PRIOR TO THE REGISTRATION OF ANY TRANSFER IN ACCORDANCE WITH CLAUSE (C) ABOVE, THE

COMPANY RESERVES THE RIGHT TO REQUIRE THE DELIVERY OF SUCH LEGAL OPINIONS, CERTIFICATIONS OR OTHER EVIDENCE AS MAY REASONABLY BE REQUIRED IN ORDER TO DETERMINE THAT THE PROPOSED TRANSFER IS BEING MADE IN COMPLIANCE WITH THE SECURITIES ACT AND APPLICABLE STATE SECURITIES LAWS. NO REPRESENTATION IS MADE AS TO THE AVAILABILITY OF ANY RULE 144 EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE SECURITIES ACT.

MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES

TO ENSURE COMPLIANCE WITH TREASURY DEPARTMENT CIRCULAR NO. 230, PROSPECTIVE HOLDERS OF BONDS ARE HEREBY NOTIFIED THAT: (A) ANY DISCUSSION OF U.S. FEDERAL TAX ISSUES IN THIS OFFERING MEMORANDUM IS NOT INTENDED OR WRITTEN TO BE RELIED UPON, AND CANNOT BE RELIED UPON, BY ANY HOLDER FOR THE PURPOSE OF AVOIDING PENALTIES THAT MAY BE IMPOSED ON SUCH HOLDER UNDER THE INTERNAL REVENUE CODE OF 1986, AS AMENDED (THE "CODE"); (B) SUCH DISCUSSION IS BEING USED IN CONNECTION WITH THE PROMOTION OR MARKETING (WITHIN THE MEANING OF CIRCULAR NO. 230) BY THE COMPANY OF THE BONDS; AND (C) HOLDERS SHOULD SEEK TAX ADVICE BASED ON THEIR PARTICULAR CIRCUMSTANCES FROM AN INDEPENDENT TAX ADVISOR.

The following discussion summarizes material U.S. federal income tax considerations to U.S. Holders and Non-U.S. Holders (each, as defined below) of the purchase, ownership and disposition of the Bonds. It is included herein for general information purposes only and does not address all tax considerations that may be relevant to investors in light of their personal investment circumstances or that may be relevant to certain types of investors subject to special rules (for example, financial institutions, tax-exempt organizations, insurance companies, regulated investment companies, persons that are broker-dealers, traders in securities who elect the mark to market method of tax accounting for their securities, U.S. Holders that have a functional currency other than the

U.S. dollar, certain former U.S. citizens or long-term residents, retirement plans, real estate investment trusts, foreign governments, international organizations, controlled foreign corporations, passive foreign investment companies, investors in partnerships or other pass-through entities or persons holding the Bonds as part of a "straddle," "hedge," "conversion transaction" or other integrated transaction). The discussion set forth below is limited to initial investors who hold the Bonds as capital assets within the meaning of Section 1221 of the Code and who purchase the Bonds for cash at the initial "issue price" (i.e., the first price to the public at which a substantial amount of the Bonds is sold for money, excluding bond houses, brokers or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers). In addition, this discussion does not address the effect of U.S. federal alternative minimum tax, gift or estate tax laws, or any state, local or foreign tax laws. Furthermore, the discussion below is based upon provisions of the Code, the legislative history thereof, U.S. Trea- sury regulations thereunder and administrative rulings and judicial decisions thereunder as of the date hereof. Such authorities may be repealed, revoked or modified (including changes in effective dates, and possibly with retroactive effect) so as to result in U.S. federal income tax considerations different from those discussed below. We have not sought any rulings from the Internal Revenue Service ("IRS") with respect to the statements and conclusions made in the following discussion, and there can be no assurance that the IRS will agree with such statements and conclusions or that a court will not sustain any challenge by the IRS in the event of litigation.

For purposes of the following discussion, a "U.S. Holder" means a beneficial owner of the Bonds that is for S. federal income tax purposes:

- an individual who is a citizen or resident of the U.S.;
- a corporation (or any entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust, if (i) a U.S. court is able to exercise primary supervision over the administration of the trust and one or more United States persons have the authority to control all substantial decisions of the trust or (ii) the trust has a valid election in place to be treated as a United States person for U.S. federal income tax purposes.

For purposes of the following discussion, a "Non-U.S. Holder" means a beneficial owner of the Bonds (other than a partnership or an entity or arrangement treated as a partnership for U.S. federal income tax purposes) that is not a U.S. Holder for U.S. federal income tax purposes.

If an entity or arrangement treated as a partnership for U.S. federal income tax purposes is a beneficial owner of a Bond, the U.S. federal income tax treatment of a partner in the partnership generally will depend upon the status of the partner and upon the activities of the partnership. Partnerships and partners in such partnerships should consult their own tax advisors about the tax consequences of the purchase, ownership and disposition of the Bonds.

THIS DISCUSSION OF MATERIAL U.S. FEDERAL INCOME TAX CONSIDERATIONS IS NOT INTENDED, AND SHOULD NOT BE CONSTRUED, TO BE TAX OR LEGAL ADVICE TO ANY PARTICULAR INVESTOR IN OR HOLDER OF THE BONDS. PROSPECTIVE INVESTORS ARE ADVISED TO CONSULT THEIR OWN TAX ADVISORS CONCERNING THE APPLICATION OF THE U.S. FEDERAL INCOME TAX LAWS TO THEIR PARTICULAR SITUATIONS AS WELL AS ANY TAX CONSIDERATIONS ARISING UNDER THE LAWS OF ANY STATE, LOCAL OR FOREIGN TAXING JURISDICTION OR ANY APPLICABLE TAX TREATIES, AND THE POSSIBLE EFFECT OF CHANGES IN APPLICABLE TAX LAW.

Effect of Certain Additional Payments

In certain circumstances (for example, see "Description of the Bonds — Redemption" and "Registered Exchange Offer; Registration Rights — Liquidated Damages") we may be obligated to pay amounts on the Bonds that are in excess of stated interest or principal on the Bonds. These potential payments may implicate the provisions of the Treasury Regulations relating to "contingent payment debt instruments" (the "CPDI Regulations"). One or more contingencies will not cause the Bonds to be treated as a contingent payment debt instrument if, as of the issue date, each such contingency is considered remote or incidental or, in certain circumstances, it is significantly more likely than not that none of the contingencies will occur. We believe that the potential for additional payments on the Bonds should not cause the Bonds to be treated as contingent payment debt instruments under the CPDI Regulations. Our determination is binding on a holder unless such a holder discloses its contrary position in the manner required by applicable Treasury Regulations. However, the IRS may take a different position, which could require a holder to accrue income on its Bonds in excess of stated interest, and to treat any income realized on the taxable disposition of a Bond as ordinary income rather than capital gain. The remainder of this discussion assumes that the Bonds will not be treated as contingent payment debt instruments. Investors should consult their own tax advisors regarding the possible application of the contingent payment debt instrument rules to the Bonds.

U.S. Holders

Stated Interest

We expect, and this discussion assumes, that the Bonds will not be issued with more than a *"de minimis"* amount of original issue discount for U.S. federal income tax purposes, if any. Accordingly, the stated interest on the Bonds will be included in income by a U.S. Holder as ordinary income as such interest is received or accrued in accordance with the U.S. Holder's method of accounting for U.S. federal income tax purposes. However, if the Bonds are issued with more than a *de minimis* amount of original issue discount, each U.S. Holder generally will be required to include original issue discount in its income as it accrues, regardless of its regular method of tax accounting, using a constant yield method, possibly before such U.S. Holder receives any payment attributable to such income. The rules regarding original issue discount are complex and U.S. Holders should consult their own tax advisors regarding their application.

Sale, Taxable Exchange, Redemption or Other Taxable Disposition of the Bonds

Upon a sale, taxable exchange, redemption (including any optional redemption) or other taxable disposition of a Bond, a U.S. Holder generally will recognize gain or loss equal to the difference between the amount realized on the disposition, other than amounts attributable to accrued but unpaid interest not yet taken into income which will be taxed as ordinary income, and the U.S. Holder's adjusted tax basis in the Bond. A U.S. Holder's adjusted tax basis in a Bond generally will equal the cost of the Bond to such holder, less any principal payments received by such holder. Any gain or loss generally will constitute capital gain or loss and will be long-term capital gain or loss if the U.S. Holder has held the Bond for longer than 12 months. Long-term capital gain, in the case of noncorporate taxpayers, is eligible for preferential rates of taxation. Under current law, the deductibility of capital losses is subject to limitations.

Medicare Tax

For taxable years beginning after December 31, 2012, a U.S. Holder that is an individual or estate, or a trust that does not fall into a special class of trusts that is exempt from such tax, will be subject to a 3.8% tax on the lesser of (1) the U.S. Holder's "net investment income" (in the case of individuals) or "undistributed net investment income" (in the case of estates and trusts) for the relevant taxable year and (2) the excess of the U.S. Holder's "modified adjusted gross income" (in the case of individuals) or "adjusted gross income" (in the case of estates and trusts) for the taxable year over a certain threshold (which in the case of individuals will be between $125,000 and $250,000, depending on the individual's circumstances). A U.S. Holder's net investment income generally will include its interest income on the Bonds and its net gains from the disposition of the Bonds, unless such interest income or net gains are derived in the ordinary course of the conduct of a trade or business (other than a trade or business that consists of certain passive or trading activities). U.S. Holders that are individuals, estates or trusts should consult their own tax advisors regarding the applicability of the Medicare tax to their income and gains in respect of their investment in the Bonds.

Registered Exchange Offer

We have agreed, subject to certain exceptions, to exchange the Bonds for the Exchange Bonds. The exchange of Bonds for Exchange Bonds pursuant to the Registered Exchange Offer will not constitute a taxable event for
S. federal income tax purposes. As a result:

- a U.S. Holder will not recognize taxable gain or loss as a result of the exchange of its Bonds for Exchange Bonds pursuant to the Registered Exchange Offer;
- the holding period of the Exchange Bonds will include the holding period of the Bonds surrendered in exchange therefor; and
- a U.S. Holder's adjusted tax basis in the Exchange Bonds will be the same as the U.S. Holder's adjusted tax basis in the Bonds surrendered therefor.

Information Reporting and Backup Withholding

Under the Code, U.S. Holders may be subject, under certain circumstances, to information reporting and "backup withholding" with respect to cash payments in respect of principal, interest and the gross proceeds from dispositions of the Bonds, unless the U.S. Holder is an exempt recipient. Backup withholding applies only if the U.S. Holder fails to furnish its social security or other taxpayer identification number ("TIN") to the Paying Agent and to comply with certain certification procedures or otherwise fails to establish an exemption from backup withholding. Backup withholding is not an additional tax. Any amount withheld from a payment to a U.S. Holder under the backup withholding rules is allowable as a credit (and may entitle such holder to a refund) against such U.S. Holder's U.S. federal income tax liability, provided that the required information is furnished to the IRS in a timely manner. Certain persons are exempt from backup withholding. U.S. Holders should consult their own tax advisors as to their qualification for exemption from backup withholding and the procedure for obtaining such exemption.

Non-U.S. Holders

Stated Interest

Subject to the discussion of backup withholding below, payments of interest on the Bonds to a Non-U.S. Holder generally will not be subject to U.S. withholding tax provided that (1) the Non-U.S. Holder does not actually or constructively own 10% or more of the total combined voting power of all classes of our voting stock, (2) the Non-U.S. Holder is not (a) a controlled foreign corporation that is related to us through actual or deemed stock ownership or (b) a bank receiving interest on an extension of credit made pursuant to a loan agreement entered into in the ordinary course of business, (3) such interest is not effectively connected with the conduct by the Non-U.S. Holder of a trade or business within the United States, and (4) either (a) the Non-U.S. Holder provides its name and address on an IRS Form W-8BEN (or other applicable form) and certifies, under penalties of perjury, that it is not a United States person as defined under the Code or (b) a securities clearing organization, bank or other financial institution holding the Bonds on the Non-U.S. Holder's behalf certifies, under penalties of perjury, that it has received a properly executed IRS Form W-8BEN from the Non-U.S. Holder and it provides the withholding agent with a copy.

If a Non-U.S. Holder cannot satisfy the requirements in the preceding paragraph, payments of interest made to such Non-U.S. Holder will be subject to U.S. federal withholding tax, currently at a rate of 30%, unless such Non-U.S. Holder (1) timely provides the withholding agent with a properly executed IRS Form W-8BEN (or other applicable form) claiming an exemption from or reduction in withholding under the benefit of an applicable income tax treaty or IRS Form W-8ECI (or other applicable form) certifying that interest paid on the Bonds is not subject to U.S. federal withholding tax because it is effectively connected with such Non-U.S. Holder's conduct of a trade or business in the United States, or (2) otherwise properly establishes an exemption from withholding taxes.

If interest on the Bonds is effectively connected with the conduct by a Non-U.S. Holder of a trade or business within the United States (and, if certain tax treaties apply, is attributable to a U.S. permanent establishment maintained by the Non-U.S. Holder), such interest will be subject to U.S. federal income tax on a net income basis at the rate applicable to United States persons generally (and a Non-U.S. Holder that is treated as a corporation for U.S. federal income tax purposes may also be subject to a branch profits tax equal to 30% of its effectively connected earnings and profits, subject to certain adjustments, unless such holder qualifies for a lower rate under an applicable income tax treaty). If interest is subject to U.S. federal income tax on a net income basis in accordance with these rules, such payments will not be subject to U.S. federal withholding tax so long as the relevant Non-U.S. Holder timely provides the withholding agent with the appropriate documentation.

Sale, Taxable Exchange, Redemption or Other Taxable Disposition of the Bonds

Subject to the discussion of backup withholding below, any gain realized by a Non-U.S. Holder on the sale, taxable exchange, redemption or other taxable disposition of the Bonds generally will not be subject to U.S. federal income tax, unless (1) such gain is effectively connected with the conduct by such Non-U.S. Holder of a trade or business within the United States (and, if certain tax treaties apply, is attributable to a U.S. permanent establishment maintained by the Non-U.S. Holder), in which case such gain will be taxed on a net income basis in the same manner as interest that is effectively connected with the Non-U.S. Holder's conduct of a trade or business within the United States (and a Non-U.S. Holder that is treated as a corporation for U.S. federal income tax purposes may also be subject to the branch profits tax as described above) or (2) the Non-U.S. Holder is an individual who is present in the United States for 183 days or more in the taxable year of disposition and certain other conditions are satisfied, in which case the Non-U.S. Holder will be subject to a tax, currently at a rate of 30%, on the excess, if any, of such gain plus all other U.S source capital gains recognized during the same taxable year over the Non-U.S. Holder's U.S. source capital losses recognized during such taxable year.

Registered Exchange Offer

The exchange of Bonds for Exchange Bonds pursuant to the Registered Exchange Offer will not constitute a taxable event for U.S. federal income tax purposes. As a result, the U.S. federal income tax consequences for Non- US Holders who exchange Bonds for Exchange Bonds pursuant to the Registered Exchange Offer will be the same as discussed above for U.S. Holders under — "U.S. Holders — Exchange Offer."

Information Reporting and Backup Withholding

A Non-U.S. Holder may be subject to annual information reporting and U.S. federal backup withholding on payments of interest and proceeds of a sale or other disposition of the Bonds unless such Non-U.S. Holder provides the certification described above under "Non-U.S. Holders — *Stated Interest*" or otherwise establishes an exemption from backup withholding. Backup withholding is not an additional tax and will be refunded or allowed as a credit against the Non-U.S. Holder's U.S. federal income tax liability (if any), provided the required information is furnished to the IRS in a timely manner. In any event, we generally will be required to file information returns with the IRS reporting our payments on the Bonds. Copies of the information returns may also be made available to the tax authorities in the country in which a Non-U.S. Holder resides under the provisions of an applicable income tax treaty.

Non-U.S. Holders should consult their own tax advisors regarding the application of the information reporting and backup withholding rules in their particular situations, the availability of an exemption therefrom and the procedure for obtaining such an exemption, if available.

Recently Enacted Legislation

Based on recently enacted legislation, certain account information with respect to U.S. Holders who hold Bonds through certain foreign financial institutions may be reportable to the IRS. Investors should consult with their own tax advisors regarding the possible implications of this recently enacted legislation on their investment in the Bonds.

THE PRECEDING DISCUSSION IS FOR GENERAL INFORMATION PURPOSES ONLY AND IS NOT TAX ADVICE. ACCORDINGLY, EACH PROSPECTIVE HOLDER OF A BOND SHOULD CONSULT ITS OWN TAX ADVISOR AS TO THE PARTICULAR TAX CONSEQUENCES TO IT OF PURCHASING, OWNING AND DISPOSING OF BONDS, INCLUDING THE APPLICABILITY AND EFFECT OF ANY STATE, LOCAL OR FOREIGN TAX LAWS, AND OF ANY PROPOSED CHANGES IN APPLICABLE LAW.

PLAN OF DISTRIBUTION

Under the terms and subject to the conditions contained in a purchase agreement dated November 8, 2010 (the "Purchase Agreement"), we have agreed to sell to the initial purchasers, for whom Credit Suisse Securities (USA) LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated are acting as representatives, and the initial purchasers have severally agreed to purchase, the following respective principal amounts of Bonds:

Initial Purchasers	Principal Amount of the 2015 Bonds	Principal Amount of the 2020 Bonds	Principal Amount of the 2040 Bonds
Credit Suisse Securities (USA) LLC	$ 50,000,000	$100,000,000	$150,000,000
Merrill Lynch, Pierce, Fenner & Smith Incorporated	50,000,000	100,000,000	150,000,000
BNP Paribas Securities Corp.	25,000,000	50,000,000	75,000,000
Mitsubishi UFJ Securities (USA), Inc.	25,000,000	50,000,000	75,000,000
RBS Securities Inc.	25,000,000	50,000,000	75,000,000
Scotia Capital (USA) Inc.	25,000,000	50,000,000	75,000,000
BBVA Securities Inc.	10,000,000	20,000,000	30,000,000
RBC Capital Markets, LLC	10,000,000	20,000,000	30,000,000
Santander Investment Securities Inc.	10,000,000	20,000,000	30,000,000
SunTrust Robinson Humphrey, Inc.	10,000,000	20,000,000	30,000,000
The Williams Capital Group, L.P.	10,000,000	20,000,000	30,000,000
Total	$250,000,000	$500,000,000	$750,000,000

The Purchase Agreement provides that the initial purchasers are obligated to purchase all of the Bonds if any are purchased. The Purchase Agreement also provides that if an initial purchaser defaults, the purchase commit- ments of nondefaulting initial purchasers may be increased or the offering may be terminated.

The initial purchasers propose to offer each series of Bonds initially at the respective offering price on the cover page of this offering memorandum for the applicable series and may also offer the Bonds to selling group members at the offering price less a selling concession. After the initial offering, the offering price may be changed.

The Bonds have not been registered under the Securities Act and may not be offered or sold within the United States or to, or for the account or benefit of, U.S. persons except to qualified institutional buyers in reliance on Rule 144A under the Securities Act and to non-U.S. persons in offshore transactions in reliance on Regulation S under the Securities Act. Each of the initial purchasers has agreed that, except as permitted by the Purchase Agreement, it will not offer, sell or deliver the Bonds (i) as part of its distribution at any time or (ii) otherwise until 40 days after the later of the commencement of the offering and the closing date, within the United States or to, or for the account or benefit of, U.S. persons, and it will have sent to each broker/dealer to which it sells Bonds in reliance on Regulation S during such 40-day period, a confirmation or other notice detailing the restrictions on offers and sales of the Bonds within the United States or to, or for the account or benefit of, U.S. persons. Terms used in this paragraph have the meanings given to them by Regulation S under the Securities Act. Resales of the Bonds are restricted as described under "Transfer Restrictions."

In addition, until 40 days after the commencement of the offering, an offer or sale of Bonds within the United States by a broker/dealer (whether or not it is participating in the offering) may violate the registration requirements of the Securities Act if such offer or sale is made otherwise than pursuant to Rule 144A.

Each of the initial purchasers severally will represent and agree that:

- it has not offered or sold and prior to the expiry of a period of six months from the closing date, will not offer or sell any Bonds to persons in the United Kingdom except to persons whose ordinary activities involve them in acquiring, holding, managing or disposing of investments (as principal or agent) for the purposes of their businesses or otherwise in circumstances which have not resulted and will not result in an offer to the public in the United Kingdom within the meaning of the Public Offers of Securities Regulations 1995;

- it has only communicated or caused to be communicated and will only communicate or cause to be communicated any invitation or inducement to engage in investment activity (within the meaning of section 21 of the Financial Services and Markets Act 2000 (the "FSMA")) received by it in connection with the issue or sale of any Bonds in circumstances in which section 21(1) of the FSMA does not apply to the Issuer; and

- it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Bonds in, from or otherwise involving the United Kingdom.

We have agreed to indemnify the initial purchasers against liabilities or to contribute to payments which they may be required to make in that respect.

The Bonds of each series are a new issue of securities for which there currently is no market. The initial purchasers have advised us that they intend to make a market in the Bonds as permitted by applicable law. They are not obligated, however, to make a market in the Bonds and any market-making may be discontinued at any time at their sole discretion. Accordingly, no assurance can be given as to the development or liquidity of any market for the Bonds.

The initial purchasers may engage in over-allotment, stabilizing transactions, covering transactions and penalty bids in accordance with Regulation M under the Exchange Act.

- Over-allotment involves sales in excess of the offering size, which creates a short position for the initial purchasers.

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

- Covering transactions involve purchases of the Bonds in the open market after the distribution has been completed in order to cover short positions.

- Penalty bids permit the initial purchasers to reclaim a selling concession from a broker/dealer when the Bonds originally sold by such broker/dealer are purchased in a stabilizing or covering transaction to cover short positions.

These stabilizing transactions, covering transactions and penalty bids may cause the price of the Bonds to be higher than it would otherwise be in the absence of these transactions. These transactions, if commenced, may be discontinued at any time.

We expect that delivery of the Bonds will be made against payment therefor on or about November 16, 2010, which will be the fifth business day following the date of pricing of the Bonds (T+5). Trades in the secondary market generally are required to settle in three business days (T+3), unless the parties to any such trade expressly agree otherwise. Accordingly, purchasers who wish to trade Bonds on the date of pricing or the next succeeding business day will be required, by virtue of the fact that the Bonds initially will settle T+5, to specify an alternate settlement cycle. Purchasers of the Bonds who wish to trade Bonds on the date of pricing or the next succeeding business day should consult their own advisor.

Other Relationships and Conflicts of Interest

Certain of the initial purchasers and their respective affiliates have from time to time in the past and may in the future perform various financial advisory, investment banking and other services for us and our affiliates in the ordinary course of business, for which they received and may receive customary fees and expenses. In particular, affiliates of the representatives and other initial purchasers are lenders and/or agents under our credit facilities and certain credit facilities of our affiliates.

LEGAL MATTERS

The validity of the Bonds offered hereby will be passed upon for us by Dewey & LeBoeuf LLP, New York, New York and John R. McCall, Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer to the Company. Certain legal matters will be passed upon for the initial purchasers by Davis Polk & Wardwell LLP, New York, New York. However, matters pertaining to our organization, our title to property and the lien of the Mortgage upon our properties will be passed upon only by Mr. McCall and Stoll Keenon Ogden PLLC. As to matters involving the law of the Commonwealths of Kentucky and Virginia and the State of Tennessee, Dewey & LeBoeuf LLP and Davis Polk & Wardwell LLP will rely upon the opinions of Mr. McCall and Stoll Keenon Ogden PLLC.

INDEPENDENT AUDITORS

The financial statements of Kentucky Utilities Company as of December 31, 2009 and 2008 and for each of the three years in the period ended December 31, 2009 included in this offering memorandum and the effectiveness of internal control over financial reporting as of December 31, 2009 have been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report appearing therein.

KENTUCKY UTILITIES COMPANY

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Kentucky Utilities Company

Financial Statements

As of December 31, 2009 and 2008
and For the Years Ended
December 31, 2009, 2008 and 2007

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
CAIR	Clean Air Interstate Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	KU
CT	Combustion Turbines
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
E.ON U.S. Services	E.ON U.S. Services Inc.
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
GHG	Greenhouse Gas
Gwh	Gigawatt hours or one thousand Mwh
IBEW	International Brotherhood of Electrical
IMEA	Workers Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
Kwh	Kilowatt hours
LG&E	Louisville Gas and Electric Company
LG&E Energy	LG&E Energy LLC (now E.ON U.S. LLC)
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investor Services, Inc.
MVA	Megavolt-ampere
Mw	Megawatts
Mwh	Megawatt hours
NERC	North American Electric Reliability Corporation
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation

PUHCA 2005	Public Utility Holding Company Act of 2005
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Rating Services
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
VDT	Value Delivery Team Process
Virginia Commission. . .	Virginia State Corporation Commission

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Kentucky Utilities Company

Statements of Income

	Years Ended December 31		
	2009	2008	2007
	(Millions of $)		
OPERATING REVENUES:			
Total operating revenues (Note 11)	$1,355	$1,405	$1,272
OPERATING EXPENSES:			
Fuel for electric generation	434	513	461
Power purchased (Notes 9 and 11)	199	221	168
Other operation and maintenance expenses	320	275	255
Depreciation and amortization (Note 1)	133	136	121
Total operating expenses	1,086	1,145	1,005
Net operating income	269	260	267
Equity in earnings of EEI (Note 1)	(1)	(30)	(26)
Other income — net	(5)	(8)	(7)
Interest expense (Notes 7 and 8)	6	14	15
Interest expense to affiliated companies (Notes 8 and 11)	69	58	41
Income before income taxes	200	226	244
Federal and state income taxes (Note 6)	67	68	77
Net income	$ 133	$ 158	$ 167

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

Kentucky Utilities Company

Statements of Retained Earnings

	Years Ended December 31		
	2009	**2008**	**2007**
	(Millions of $)		
Balance January 1	$1,195	$1,037	$ 870
Add net income	133	158	167
Balance December 31	$1,328	$1,195	$1,037

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

Kentucky Utilities Company

Balance Sheets

	December 31 2009	December 31 2008
	(Millions of $)	
ASSETS:		
Current assets:		
Cash and cash equivalents (Note 1)	$ 2	$ 2
Restricted cash (Note 1)	—	9
Accounts receivable, net: (Notes 1 and 11)		
Customer — less reserves of $1 million and $3 million as of December 31, 2009 and 2008, respectively	155	152
Other — less reserves of $2 million and less than $1 million as of December 31, 2009 and 2008	27	32
Materials and supplies (Note 1):		
Fuel (predominantly coal)	98	73
Other materials and supplies	39	36
Deferred income taxes — net (Note 6)	3	2
Regulatory assets (Note 2)	32	32
Prepayments and other current assets	10	8
Total current assets	366	346
Other property and investments (Note 1)	12	23
Utility plant, at original cost (Note 1):	4,892	4,446
Less: reserve for depreciation	1,838	1,724
Total utility plant, net	3,054	2,722
Construction work in progress	1,257	1,176
Total utility plant and construction work in progress	4,311	3,898
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension benefits	105	137
Other	117	64
Cash surrender value of key man life insurance	38	39
Other assets	7	11
Total deferred debits and other assets	267	251
Total Assets	$4,956	$4,518

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

Kentucky Utilities Company

Balance Sheets (continued)

	December 31 2009	December 31 2008
	(Millions of $)	
LIABILITIES AND EQUITY:		
Current liabilities:		
Current portion of long-term debt (Note 7)	$ 261	$ 228
Notes payable to affiliated companies (Notes 8 and 11)	45	16
Accounts payable	107	155
Accounts payable to affiliated companies (Note 11)	88	38
Customer deposits	22	21
Regulatory liabilities (Note 2)	3	5
Other current liabilities	42	34
Total current liabilities	568	497
Long-term debt:		
Long-term bonds (Note 7)	123	123
Long-term debt to affiliated company (Notes 7 and 11)	1,298	1,181
Total long-term debt	1,421	1,304
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 6)	336	279
Accumulated provision for pensions and related benefits (Note 5)	160	186
Investment tax credit (Note 6)	104	80
Asset retirement obligations	34	32
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	331	329
Deferred income taxes	9	16
Postretirement benefits	9	10
Other	11	15
Other liabilities	21	26
Total deferred credits and other liabilities	1,015	973
Commitments and contingencies (Note 9)		
COMMON EQUITY:		
Common stock, without par value — Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital (Note 11)	316	241
Retained earnings	1,318	1,174
Undistributed subsidiary earnings	10	21
Total retained earnings	1,328	1,195
Total common equity	1,952	1,744
Total Liabilities and Equity	$4,956	$4,518

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

Kentucky Utilities Company

Statements of Cash Flows

	Years Ended December 31		
	2009	2008	2007
	(Millions of $)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 133	$ 158	$ 167
Items not requiring cash currently:			
Depreciation and amortization	133	136	121
Deferred income taxes — net	50	(13)	(5)
Investment tax credit — net	24	25	42
Provision for pension and postretirement plans	26	10	11
Other	—	1	(4)
Change in certain current assets and liabilities:			
Accounts receivable	(4)	12	(16)
Materials and supplies	(28)	(33)	22
Prepayments and other current assets	(3)	(1)	1
Accounts payable	(3)	9	(15)
Other current liabilities	8	5	4
Pension and postretirement funding	(20)	(5)	(19)
Storm restoration regulatory asset	(57)	(2)	—
Other	(6)	(10)	2
Net cash provided by operating activities	253	292	311
CASH FLOWS FROM INVESTING ACTIVITIES:			
Construction expenditures	(516)	(686)	(749)
Assets purchased from affiliate	—	(10)	—
Change in restricted cash	9	1	12
Net cash used for investing activities	(507)	(695)	(737)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Long-term borrowings from affiliated company (Note 7)	150	250	448
Short-term borrowings from affiliated company — net (Note 8)	29	(7)	(74)
Retirement of first mortgage bonds	—	—	(107)
Issuance of pollution control bonds	—	77	78
Retirement of pollution control bonds	—	(60)	—
Acquisition of outstanding bonds	—	(80)	—
Reissuance of reacquired bonds	—	63	—
Retirement of reacquired bonds	—	17	—
Additional paid-in capital	75	145	75
Net cash provided by financing activities	254	405	420
Change in cash and cash equivalents	—	2	(6)
Cash and cash equivalents at beginning of year	2	—	6
Cash and cash equivalents at end of year	$ 2	$ 2	$ —
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Income taxes	$ (9)	$ 46	$ 38
Interest on borrowed money	3	13	16
Interest to affiliated companies on borrowed money	67	53	29

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

Kentucky Utilities Company

Statements of Capitalization

	December 31 2009	December 31 2008
	(Millions of $)	
LONG-TERM DEBT (Note 7):		
Pollution control series:		
Mercer Co. 2000 Series A, due May 1, 2023, variable%	$ 13	$ 13
Carroll Co. 2002 Series A, due February 1, 2032, variable%	21	21
Carroll Co. 2002 Series B, due February 1, 2032, variable%	2	2
Muhlenberg Co. 2002 Series A, due February 1, 2032, variable%	2	2
Mercer Co. 2002 Series A, due February 1, 2032, variable%	8	8
Carroll Co. 2002 Series C, due October 1, 2032, variable%	96	96
Carroll Co. 2004 Series A, due October 1, 2034, variable%	50	50
Carroll Co. 2006 Series B, due October 1, 2034, variable%	54	54
Carroll Co. 2007 Series A, due February 1, 2026, 5.75%	18	18
Trimble Co. 2007 Series A, due March 1, 2037, 6.0%	9	9
Carroll Co. 2008 Series A, due February 1, 2032, variable%	78	78
Total pollution control series	351	351
Notes payable to Fidelia:		
Due November 24, 2010, 4.24%, unsecured	33	33
Due January 16, 2012, 4.39%, unsecured	50	50
Due April 30, 2013, 4.55%, unsecured	100	100
Due August 15, 2013, 5.31%, unsecured	75	75
Due December 19, 2014, 5.45%, unsecured	100	100
Due July 8, 2015, 4.735%, unsecured	50	50
Due December 21, 2015, 5.36%, unsecured	75	75
Due October 25, 2016, 5.675%, unsecured	50	50
Due April 24, 2017, 5.28%, unsecured	50	—
Due June 20, 2017, 5.98%, unsecured	50	50
Due July 25, 2018, 6.16%, unsecured	50	50
Due August 27, 2018, 5.645%, unsecured	50	50
Due December 17, 2018, 7.035%, unsecured	75	75
Due July 29, 2019, 4.81%, unsecured	50	—
Due October 25, 2019, 5.71%, unsecured	70	70
Due November 25, 2019, 4.445%, unsecured	50	—
Due February 7, 2022, 5.69%, unsecured	53	53
Due May 22, 2023, 5.85%, unsecured	75	75
Due September 14, 2028, 5.96%, unsecured	100	100
Due June 23, 2036, 6.33%, unsecured	50	50
Due March 30, 2037, 5.86%, unsecured	75	75
Total notes payable to Fidelia	1,331	1,181
Total long-term debt outstanding	1,682	1,532
Less current portion of long-term debt	261	228
Long-term debt	1,421	1,304
COMMON EQUITY:		
Common stock, without par value —		
Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in-capital (Note 11)	316	241
Retained earnings	1,318	1,174
Undistributed subsidiary earnings	10	21
Total retained earnings	1,328	1,195
Total common equity	1,952	1,744
Total capitalization	$3,373	$3,048

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

Kentucky Utilities Company

Notes to Financial Statements

Note 1 — Summary of Significant Accounting Policies

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 515,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 square miles. Approximately 99% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled CTs. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution and sale of natural gas in Kentucky.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2009 presentation with no impact on net assets, liabilities and capitalization or previously reported net income. However, for 2008 cash from operations was decreased by $5 million and cash flows from investing increased by
$5 million and for 2007 cash from operations increased by $4 million and cash flows from investing decreased by $4 million.

Regulatory Accounting. KU is subject to the regulated operations guidance of the FASB ASC, under which regulatory assets are created based on expected recovery from customers in future rates to defer costs that would otherwise be charged to expense. Likewise, regulatory liabilities are created based on expected return to customers in future rates to defer credits that would otherwise be reflected as income, or, in the case of costs of removal, are created to match long-term future obligations arising from the current use of assets. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each item as prescribed by the FERC, the Kentucky Commission or the Virginia Commission. See Note 2, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Cash and Cash Equivalents. KU considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) are held in trust pending expenditure for qualifying assets.

Allowance for Doubtful Accounts. The allowance for doubtful accounts included in customer accounts receivable is based on the ratio of the amounts charged-off during the last twelve months to the retail revenues billed over the same period multiplied by the retail revenues billed over the last four months. Accounts with no payment activity are charged-off after four months, although collection efforts continue thereafter. The allowance for doubtful accounts included in other accounts receivable is composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible.

Materials and Supplies. Fuel and other materials and supplies inventories are accounted for using the average-cost method. Emission allowances are included in other materials and supplies. At December 31, 2009 and 2008, the emission allowances inventory was $1 million and less than $1 million, respectively.

Other Property and Investments. Other property and investments on the balance sheets consists of KU's investment in EEI, KU's investment in OVEC, funds related to the long-term power purchase contract with OMU and non-utility plant.

Although KU holds investment interests in OVEC and EEI, it is not the primary beneficiary, therefore, neither are consolidated into the Company's financial statements. KU and 10 other electric utilities are owners of OVEC,
located in Piketon, Ohio. OVEC owns and operates two coal-fired power plants, Kyger Creek Station in Ohio and

Clifty Creek Station in Indiana. OVEC's power is currently supplied to KU and 12 other companies affiliated with the various owners. Pursuant to current contractual agreements, KU owns 2.5% of OVEC's common stock and is contractually entitled to 2.5% of OVEC's output, approximately 55 Mw of generation capacity.

As of December 31, 2009 and 2008, KU's investment in OVEC totaled less than $1 million and is accounted for under the cost method of accounting. The direct exposure to loss as a result of its involvement with OVEC is generally limited to the value of its investment. See Note 9, Commitments and Contingencies, for further discussion of developments regarding KU's ownership interests and power purchase rights.

KU owns 20% of the common stock of EEI, which owns and operates a 1,162-Mw generating station in southern Illinois. EEI, through a power marketer affiliated with its majority owner, sells its output to third parties. KU's investment in EEI is accounted for under the equity method of accounting and, as of December 31, 2009 and 2008, totaled $12 million and $22 million, respectively. KU's direct exposure to loss as a result of its involvement with EEI is generally limited to the value of its investment.

Utility Plant. Utility plant is stated at original cost, which includes payroll-related costs such as taxes, fringe benefits and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates in Kentucky. KU has not recorded a significant allowance for funds used during construction.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost is charged to the reserve for depreciation. When complete operating units are disposed of, appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Depreciation and Amortization. Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided were approximately 2.6% in 2009, 3.0% in 2008 and 3.2% in 2007 of average depreciable plant. Of the amount provided for depreciation at December 31, 2009, approx- imately 0.4% was related to the retirement, removal and disposal costs of long lived assets. At December 31, 2008 and 2007, approximately 0.5% was related to the retirement, removal and disposal costs of long lived assets.

Unamortized Debt Expense. Debt expense is capitalized in deferred debits and amortized using the straight line method, which approximates the effective interest method, over the lives of the related bond issues.

Income Taxes. In accordance with the guidance of the FASB ASC, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, as measured by enacted tax rates that are expected to be in effect in the periods when the deferred tax assets and liabilities are expected to be settled or realized. Significant judgment is required in determining the provision for income taxes, and there are transactions for which the ultimate tax outcome is uncertain. The income taxes guidance of the FASB ASC prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Uncertain tax positions are analyzed periodically and adjustments are made when events occur to warrant a change. See Note 6, Income Taxes.

Deferred Income Taxes. Deferred income taxes are recognized at currently enacted tax rates for all material temporary differences between the financial reporting and income tax bases of assets and liabilities.

Investment Tax Credits. The EPAct 2005 added Section 48A to the Internal Revenue Code, which provides for an investment tax credit to promote the commercialization of advanced coal technologies that will generate electricity in an environmentally responsible manner. KU and LG&E received an investment tax credit related to the construction of a new base-load, coal-fired unit, TC2. See Note 6, Income Taxes. Investment tax credits prior to 2006 resulted from provisions of the tax law that permitted a reduction of KU's tax liability based on credits for construction expenditures. Deferred investment tax credits are being amortized to income over the estimated lives of the related property that gave rise to the credits.

Revenue Recognition. Revenues are recorded based on service rendered to customers through month-end. KU accrues an estimate for unbilled revenues from each meter reading date to the end of the accounting period based on allocating the daily system net deliveries between billed volumes and unbilled volumes. The allocation is

based on a daily ratio of the number of meter reading cycles remaining in the month to the total number of meter reading cycles in each month. Each day's ratio is then multiplied by each day's system net deliveries to determine an estimated billed and unbilled volume for each day of the accounting period. The unbilled revenue estimates included in accounts receivable were $76 million, $60 million and $59 million at December 31, 2009, 2008 and 2007, respectively.

Fuel Costs. The cost of fuel for generation is charged to expense as used. See Note 2, Rates and Regulatory Matters, for a description of the FAC.

Management's Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent items at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accrued liabilities, including legal and environ- mental, are recorded when they are probable and estimable. Actual results could differ from those estimates.

Recent Accounting Pronouncements. The following are recent accounting pronouncements affecting KU:

Hierarchy of Generally Accepted Accounting Principles

The guidance related to the hierarchy of generally accepted accounting principles was issued in June 2009, and is effective for interim and annual periods ending after September 15, 2009. The guidance establishes the FASB ASC as the single source of authoritative nongovernmental U.S. generally accepted accounting principles. It had no effect on the Company's results of operations, financial position or liquidity; however, references to authoritative accounting literature have changed with the adoption.

Subsequent Events

The guidance related to subsequent events was issued in May 2009, and is effective for interim and annual periods ending after June 15, 2009. This guidance requires disclosure of the date through which subsequent events have been evaluated, as well as whether that date is the date the financial statements were issued or the date they were available to be issued. The adoption of this guidance had no impact on the Company's results of operations, financial position or liquidity; however, additional disclosures were required with the adoption. See Note 12, Subsequent Events, for additional disclosures.

Interim Disclosures about Fair Value of Financial Instruments

The guidance related to interim disclosures about fair value of financial instruments was issued in April 2009, and is effective for interim and annual periods ending after June 15, 2009. This guidance requires qualitative and quantitative disclosures about fair values of assets and liabilities on a quarterly basis. The adoption had no impact on the Company's results of operations, financial position or liquidity; however, additional disclosures were required with the adoption. See Note 3, Financial Instruments, for additional disclosures.

Employers' Disclosures about Postretirement Benefit Plan Assets

The guidance related to employers' disclosures about postretirement benefit plan assets was issued in December 2008, and is effective as of December 31, 2009. This guidance requires additional disclosures related to pension and other postretirement benefit plan assets. Additional disclosures include the investment allocation decision-making process, the fair value of each major category of plan assets as well as the inputs and valuation techniques used to measure fair value and significant concentrations of risk within the plan assets. The adoption had no impact on the Company's results of operations, financial position or liquidity; however, additional disclosures were required with the adoption. See Note 5, Pension and Other Postretirement Benefit Plans, for additional disclosures.

Disclosures about Derivative Instruments and Hedging Activities

The guidance related to disclosures about derivative instruments and hedging activities was issued in March 2008, and is effective for fiscal years and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this guidance is to enhance the current disclosure framework. The adoption had no impact on KU's results of operations, financial position or liquidity; however, additional disclosures relating to derivatives were required with the adoption effective January 1, 2009. See Note 3, Financial Instruments, for additional disclosures.

<u>Noncontrolling Interests in Consolidated Financial Statements</u>

The guidance related to noncontrolling interests in consolidated financial statements was issued in December 2007, and is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this guidance is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company adopted this guidance effective January 1, 2009, and it had no impact on its results of operations, financial position or liquidity.

<u>Fair Value Measurements</u>

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances, and settlements within level 3 measurements. This guidance is effective for the first reporting period beginning after issuance except for disclosures about the roll-forward of activity in level 3 fair value measurements. This guidance will have no impact on the Company's results of operations, financial position or liquidity; however, additional disclosures will be provided as required.

In August 2009, the FASB issued guidance related to fair value measurement disclosures, which is effective for the first reporting period beginning after issuance. The guidance provides amendments to clarify and reduce ambiguity in valuation techniques, adjustments and measurement criteria for liabilities measured at fair value. The adoption had no impact on the Company's results of operations, financial position or liquidity, and no additional disclosures were required.

The guidance related to fair value measurements was issued in September 2006 and, except as described below, was effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. This guidance does not expand the application of fair value accounting to new circumstances.

In February 2008, guidance on fair value measurements and disclosures delayed the effective date for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. All other amendments have been evaluated and have no impact on the Company's financial statements.

The Company adopted this guidance effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and it had no impact on the results of operations, financial position or liquidity, however, additional disclosures relating to its financial derivatives and cash collateral on derivatives, as required, are now provided. Fair value accounting for all nonrecurring fair value measurements of nonfinancial assets and liabilities was adopted effective January 1, 2009, and it had no impact on the results of operations, financial position or liquidity. At December 31, 2009, no additional disclosures were required as KU did not have any nonfinancial assets or liabilities measured at fair value subsequent to initial measurement.

The guidance related to determining fair value was issued in April 2009, and is effective for interim and annual periods ending after June 15, 2009. This update provides additional guidance on determining fair values when there is no active market or where the price inputs being used represent distressed sales. The adoption had no impact on the Company's results of operations, financial position or liquidity.

Note 2 — Rates and Regulatory Matters

The Company is subject to the jurisdiction of the Kentucky Commission, the Virginia Commission, the Tennessee Regulatory Authority and the FERC in virtually all matters related to electric utility regulation, and as such, its accounting is subject to the regulated operations guidance of the FASB ASC. Given its position in the marketplace and the status of regulation in Kentucky and Virginia, there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

2010 Kentucky Rate Case

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in base electric rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. KU has requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates have been suspended until August 1, 2010, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding. The parties are currently exchanging data requests in the proceedings and a hearing date has been scheduled for June 2010. An order in the proceeding may occur during the third or fourth quarters of 2010.

2008 Kentucky Rate Case

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in base electric rates. In January 2009, KU, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's base electric rates decreased by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009, at which time the merger surcredit terminated.

In conjunction with the filing of the application for changes in base rates the VDT surcredit terminated. The VDT surcredit resulted from a 2001 initiative to share savings of $10 million from the VDT initiative with customers over five years. In February 2006, KU and all parties to the proceeding reached a unanimous settlement agreement on the future ratemaking treatment of the VDT surcredit which was approved by the Kentucky Commission in March 2006 at an annual rate of $4 million. Under the terms of the settlement agreement, the VDT surcredit continued at its then current level until such time as KU filed for a change in base rates. In accordance with the Order, the VDT surcredit terminated in August 2008, the first billing month after the July 2008 filing for a change in base rates.

In December 2007, KU submitted its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008. The merger surcredit originated as part of the LG&E Energy merger with KU Energy Corporation in 1998. In June 2008, the Kentucky Commission issued an Order approving a unanimous settlement agreement reached with all parties to the case which provided for a reduction in the merger surcredit to approximately $6 million for a 7-month period beginning July 2008, termination of the merger surcredit when new base rates went into effect on or after January 31, 2009, and that the merger surcredit be continued at an annual rate of $12 million thereafter should the Company not file for a change in base rates. In accordance with the Order, the merger surcredit was terminated effective February 6, 2009, with the implementation of new base rates.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based upon a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. A public hearing was held during January 2010. As permitted, pursuant to a Virginia Commission order, KU elected to implement the proposed rates effective November 1, 2009, on an interim basis. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU will refund certain amounts collected since November 2009, consisting of interim increased rates in excess of the ultimate approved rates. These refunds aggregate approximately $1 million and are anticipated to occur during the second quarter of 2010. See also Note 12 to Notes to Financial Statements.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in base electric rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from current, all-in stated unit charge rates to an unbundled formula rate. In May 2009, as a result of settlement negotiations, KU submitted an unopposed motion informing the FERC of the filing of a settlement agreement and agreed-upon seven-year service agreements with the municipal customers. The unopposed motion requested interim rate structures containing terms corresponding to the overall settlement principles, to be effective from May 1, 2009, until FERC approval of the settlement agreement. The settlement and service agreements provide for unbundled formula rates which are subject to annual adjustment and approval processes. In May 2009, the FERC issued an Order approving the interim settlement with respect to rates effective May 1, 2009 representing increases of approximately 3% from prior charges and a return on equity of 11%. Additionally, during May 2009, KU filed the first annual adjustment to the formula rates to incorporate 2008 data, which adjusted formula rates became effective on July 1, 2009 and were approved by the FERC during September 2009.

Separately, the parties were not able to reach agreement on the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. In August 2009, the FERC accepted the issue for briefing and the parties completed briefing submissions during 2009. An order by the FERC on this matter may occur during 2010. KU is not currently able to predict the outcome of this proceeding, including whether its wholesale customers may or may not be entitled to certain rights or benefits relating to renewable energy, and the financial or operational effects, if any, of such outcomes.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the balance sheets as of December 31:

	2009	2008
	(In millions)	
Current regulatory assets:		
ECR	$ 28	$ 20
FAC	1	8
Net MISO exit	2	—
Other	1	4
Total current regulatory assets	$ 32	$ 32
Non-current regulatory assets:		
Storm restoration	$ 59	$ 2
ARO	30	28
Unamortized loss on bonds	12	13
Net MISO exit	9	19
Other	7	2
Subtotal non-current regulatory assets	117	64
Pension benefits	105	137
Total non-current regulatory assets	$222	$201
Current regulatory liabilities:		
DSM	$ 3	$ 5
Total current regulatory liabilities	$ 3	$ 5
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$331	$329
Deferred income taxes — net	9	16
Postretirement benefits	9	10
Other	11	15
Total non-current regulatory liabilities	$360	$370

KU does not currently earn a rate of return on the ECR and FAC regulatory assets and the Virginia levelized fuel factor included in other regulatory assets, which are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension regulatory asset that represents the changes in funded status of the plans. KU will recover this asset through pension expense included in the calculation of base rates with the Kentucky Commission and will seek recovery of this asset in future proceedings with the Virginia Commission. No return is currently earned on the ARO asset. When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability. A return is earned on the unamortized loss on bonds, and these costs are recovered through amortization over the life of the debt. The Company is seeking recovery of the Storm restoration regulatory asset and CMRG and KCCS contributions and FERC jurisdictional pension expense, included in other regulatory assets, in its current base rate cases. The Company recovers through the calculation of base rates, the amortization of the net MISO exit regulatory asset in Kentucky incurred through April 30, 2008. The Company recently received approval to recover the Virginia portion of this asset, as incurred through December 31, 2008, over a five year period and, due to the formula nature of its FERC rate structure, the FERC jurisdictional portion of the regulatory asset will be included in the annual updates to the rate formula. The Company recovers through the calculation of base rates, the amortization of the remaining regulatory assets, including other regulatory assets comprised of deferred storm costs, the East Kentucky Power Cooperative FERC transmission settlement agreement and Kentucky rate case expenses. Other regulatory liabilities include DSM, FERC jurisdictional supplies inventory and MISO administrative charges collected via base rates from May 2008 through February 5, 2009. The MISO regulatory liability will be netted against the remaining costs of withdrawing from the MISO, per a Kentucky Commission Order, in the current Kentucky base rate case.

ARO. A summary of KU's net ARO assets, regulatory assets, ARO liabilities, regulatory liabilities and cost of removal established under the asset retirement and environmental obligations guidance of the FASB ASC, follows:

(in millions of $)	ARO Net Assets	ARO Liabilities	Regulatory Assets	Regulatory Liabilities	Accumulated Cost of Removal	Cost of Removal Depreciation
As of December 31, 2006	$ 5	$(28)	$22	$ (2)	$ 2	$ 1
ARO accretion	—	(2)	2	—	—	—
As of December 31, 2007	$ 5	$(30)	$24	$ (2)	$ 2	$ 1
ARO accretion	—	(2)	2	—	—	—
Removal cost reclass	—	—	2	(2)	—	—
As of December 31, 2008	5	(32)	28	(4)	2	1
ARO accretion	—	(2)	2	—	—	—
ARO depreciation	(1)	—	—	—	—	—
Cost of removal depreciation	—	—	—	—	—	1
As of December 31, 2009	$ 4	$(34)	$30	$ (4)	$ 2	$ 2

Pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC, an offsetting regulatory credit was recorded in depreciation and amortization in the income statement of $2 million in 2009, 2008 and 2007 for the ARO accretion and depreciation expense. KU AROs are primarily related to the final retirement of assets associated with generating units. For assets associated with AROs, the removal cost accrued through depreciation under regulatory accounting is established as a regulatory liability pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC. For the years ended December 31, 2008 and 2007, KU recorded less than $1 million of depreciation expense related to the cost of removal of ARO related assets. An offsetting regulatory liability was established pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC.

KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under the asset retirement and environmental obligations guidance of the FASB ASC, no material asset retirement obligations are recorded for transmission and distribution assets.

MISO. Following receipt of applicable FERC, Kentucky Commission and other regulatory orders, related to proceedings that had been underway since July 2003, KU withdrew from the MISO effective September 1, 2006. Since the exit from the MISO, KU has been operating under a FERC-approved open access-transmission tariff. KU now contracts with the Tennessee Valley Authority to act as its transmission Reliability Coordinator and Southwest Power Pool, Inc. to function as its Independent Transmission Organization, pursuant to FERC requirements.

KU and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, the Company paid $20 million to the MISO and made related FERC compliance filings. The Company's payment of this exit fee was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. KU and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided KU with an immediate recovery of
$1 million and an estimated $3 million over the next seven years for credits realized from other payments the MISO will receive, plus interest.

In accordance with Kentucky Commission Orders approving the MISO exit, KU has established a regulatory asset for the MISO exit fee, net of former MISO administrative charges collected via Kentucky base rates through the base rate case test year ended April 30, 2008. The net MISO exit fee is subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which were collected via base rates until February 6, 2009. The approved 2008 base rate case settlement provided for MISO administrative charges collected through base rates from May 1, 2008 to February 6, 2009, and any future adjustments to the MISO exit fee, to be established as a regulatory liability until the amounts can be amortized in future base rate cases. This regulatory liability balance as of October 31, 2009 has been included in the base rate case application filed on January 29, 2010. MISO exit fee credit amounts subsequent to October 31, 2009, will continue to accumulate as a regulatory liability until they can be amortized in future base rate cases.

In November 2008, the FERC issued Orders in industry-wide proceedings relating to MISO RSG calculation and resettlement procedures. RSG charges are amounts assessed to various participants active in the MISO trading market which generally seek to compensate for uneconomic generation dispatch due to regional transmission or power market operational considerations, with some customer classes eligible for payments, while others may bear charges. The FERC Orders approved two requests for significantly altered formulas and principles, each of which the FERC applied differently to calculate RSG charges for various historical and future periods. Based upon the 2008 FERC Orders, the Company established a reserve during the fourth quarter of 2008 of less than $1 million relating to potential RSG resettlement costs for the period ended December 31, 2008. However, in May 2009, after a portion of the resettlement payments had been made, the FERC issued an Order on the requests for rehearing on one November 2008 Order which changed the effective date and reduced almost all of the previously accrued RSG resettlement costs. Therefore, these costs were reversed and a receivable was established for amounts already paid of less than $1 million, which the MISO began refunding back to the Company in June 2009, and which were fully collected by September 2009. In June 2009, the FERC issued an Order in the rate mismatch RSG proceeding, stating it will not require resettlements of the rate mismatch calculation from April 1, 2005 to November 4, 2007. An accrual had previously been recorded in 2008 for the rate mismatch issue for the time period April 25, 2006 to August 9, 2007, but no accrual had been recorded for the time period November 5, 2007 to November 9, 2008 based on the prior Order. Accordingly, the accrual for the former time period was reversed and an accrual for the latter time period was recorded in June 2009, with a net effect of $1 million of expense, substantially all of which was paid by September 2009.

In August 2009, the FERC determined that the MISO had failed to demonstrate that its proposed exemptions to real-time RSG charges were just and reasonable. In November 2009, the MISO made a compliance filing incorporating the rulings of the FERC orders and a related task force, with a primary open issue being whether certain of the tariff changes are applied prospectively only or retroactively to approximately January 6, 2009. The conclusion of the RSG matter, including the retroactivity decision, may result in refunds to the Company, but the
Company cannot predict the ultimate outcome of this matter, or its financial impact, at this time.

In November 2009, KU and LG&E filed an application with the FERC to approve certain independent transmission operator arrangements to be effective upon the expiration of their current contract with Southwest Power Pool, Inc. in September 2010. The application seeks authority for KU and LG&E to function after such date as the administrators of their own open access transmission tariffs for most purposes. The Tennessee Valley Authority, which currently acts as Reliability Coordinator, would also assume certain additional duties. A number of parties have intervened and filed comments in the matter and initial stages of data response proceedings have occurred. The application is subject to continuing FERC proceedings, including further submissions or filings by intervenors or FERC staff, prior to a ruling by the FERC. During January 2010, the Kentucky Commission issued an Order generally authorizing relevant state regulatory aspects of the proposed arrangements.

Unamortized Loss on Bonds. The costs of early extinguishment of debt, including call premiums, legal and other expenses, and any unamortized balance of debt expense are amortized using the straight line method, which approximates the effective interest method, over the life of either the replacement debt (in the case of refinancing) or the original life of the extinguished debt.

FAC. KU's retail rates contain an FAC, whereby increases and decreases in the cost of fuel for generation are reflected in the rates charged to retail customers. The FAC allows the Company to adjust customers' accounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Refunds to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. In November 2009, January 2009, June 2008 and January 2008, the Kentucky Commission issued Orders approving the charges and credits billed through the FAC for the six-month periods ending April 2009, April 2008, October 2007 and April 2007, respectively. In January 2009 and December 2006, the Kentucky Commission initiated routine examinations of the FAC for the two-year periods November 1, 2006 through October 31, 2008 and November 1, 2004 through October 31, 2006. The Kentucky Commission issued Orders in June 2009 and November 2007, approving the charges and credits billed through the FAC during the review periods.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The Virginia levelized fuel factor allows fuel recovery based on projected fuel costs for the coming year plus an adjustment for any over- or under-recovery of fuel expenses from the prior year. At December 31, 2009 and 2008, KU had a regulatory liability of less than $1 million and a regulatory asset of
$2 million, respectively.

In February 2009, KU filed an application with the Virginia Commission seeking approval of a 29% increase in its fuel cost factor beginning with service rendered in April 2009. In February 2009, the Virginia Commission issued an Order allowing the requested change to become effective on an interim basis. The Virginia Staff testimony filed in April 2009, recommended a slight decrease in the factor filed by KU. The Company indicated the Virginia Staff proposal was acceptable. A hearing was held in May 2009, with general resolution of remaining issues. In May 2009, the Virginia Commission issued an Order approving the revised fuel factor, representing an increase of 24%, effective May 2009.

In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period, April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008 customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application, to which KU has agreed. Following a public hearing and an Order in May 2008, the recommended change became effective in June 2008, resulting in a decrease of 0.482 cents/kwh from the factor in effect for the April 2007 through March 2008 period.

a return of operating expenses, and a return of and on capital invested through the ECR mechanism. The amount of

ECR. Kentucky law permits KU to recover the costs of complying with the Federal Clean Air Act, including the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires reviews of the past operations of the environmental surcharge for six- month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. In December 2009, an Order was issued approving the charges and credits billed through the ECR during the two-year period ending April 2009, an increase in the jurisdictional revenue requirement, a base rate roll-in and a revised rate of return on capital. In July 2009, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending October 2008, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In August 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month periods ending April 2008 and October 2007, and the rate of return on capital. In March 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month and two-year periods ending October 2006 and April 2007, respectively, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

In January 2010, the Kentucky Commission initiated a six-month review of KU's environmental surcharge for the billing period ending October 2009. The proceeding will progress throughout the first half of 2010.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, KU reached a unanimous settlement with all parties to the case and the Kentucky Commission issued an Order approving KU's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle.

In February 2009, the Kentucky Commission approved a settlement agreement in the rate case which provides for an authorized return on equity applicable to the ECR mechanism of 10.63% effective with the February 2009 expense month filing, which represents a slight increase over the previously authorized 10.50%.

In October 2007, KU met with the Kentucky Commission and other interested parties to discuss the status of the Ghent Unit 2 SCR construction. KU informed the Kentucky Commission that construction of the Ghent Unit 2 SCR was not going to commence before the CCN expired in December 2007, due to a change in the economics for the project. The CCN expired in December 2007, and KU has delayed construction of the Ghent Unit 2 SCR.

Storm Restoration. In January 2009, a significant ice storm passed through KU's service territory causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 44,000 customer outages. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset, and defer for future recovery, approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, the Company established a regulatory asset of $57 million for actual costs incurred, and the Company is seeking recovery of this asset in its current base rate case.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service territory causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, approximately
$3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $3 million based on its actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, the Company established a regulatory asset of $2 million for actual costs incurred, and the Company is seeking recovery of this asset in its current base rate case.
the next FERC rate proceeding.

FERC Jurisdictional Pension Costs. Other regulatory assets include pension costs of $3 million incurred by the Company and allocated to its FERC jurisdictional ratepayers. The Company will seek recovery of this asset in

Rate Case Expenses. KU incurred $1 million in expenses related to the development and support of the 2008 Kentucky base rate case. The Kentucky Commission approved the establishment of a regulatory asset for these expenses and authorized amortization over three years beginning in March 2009.

CMRG and KCCS Contributions. In July 2008, KU and LG&E, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. KU and LG&E jointly agreed to provide less than $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received and KU is seeking rate recovery in the Company's 2010 Kentucky base rate case.

Deferred Storm Costs. Based on an Order from the Kentucky Commission in June 2004, KU reclassified from maintenance expense to a regulatory asset, $4 million related to costs not reimbursed from the 2003 ice storm. These costs were amortized through June 2009. KU earned a return of these amortized costs, which were included in jurisdictional operating expenses.

Pension and Postretirement Benefits. KU accounts for pension and postretirement benefits in accordance with the compensation — retirement benefits guidance of the FASB ASC. This guidance requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability in the balance sheet and to recognize through other comprehensive income the changes in the funded status in the year in which the changes occur. Under the regulated operations guidance of the FASB ASC, KU can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky and Virginia is based on the compensation — retirement benefits guidance of the FASB ASC. Regulators have been clear and consistent with their historical treatment of such rate recovery, therefore, the Company has recorded a regulatory asset representing the change in funded status of the pension plan that is expected to be recovered and a regulatory liability representing the change in funded status of the postretirement plan that is expected to be refunded. The regulatory asset and liability will be adjusted annually as prior service cost and actuarial gains and losses are recognized in net periodic benefit cost.

Accumulated Cost of Removal of Utility Plant. As of December 31, 2009 and 2008, KU has segregated the cost of removal, previously embedded in accumulated depreciation, of $331 million and $329 million, respectively, in accordance with FERC Order No. 631. This cost of removal component is for assets that do not have a legal ARO under the asset retirement and environmental obligations guidance of the FASB ASC. For reporting purposes in the balance sheets, KU has presented this cost of removal as a regulatory liability pursuant to the regulated operations guidance of the FASB ASC.

Deferred Income Taxes — Net. These regulatory assets and liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits, the allowance for funds used during construction and deferred taxes provided at rates in excess of currently enacted rates.

DSM. KU's rates contain a DSM provision which includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows KU to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. KU and LG&E filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

<u>Other Regulatory Matters</u>

Kentucky Commission Report on Storms. In November 2009, the Kentucky Commission issued a report following review and analysis of the effects and utility response to the September 2008 wind storm and the January 2009 ice storm, and possible utility industry preventative measures relating thereto. The report suggested a number of proposed or recommended preventative or responsive measures, including consideration of selective hardening of facilities, altered vegetation management programs, enhanced customer outage communications and similar measures. In March 2010, the Companies filed a joint response reporting on their actions with respect to such recommendations. The response indicated implementation or completion of substantially all of the recommen- dations, including, among other matters, on-going reviews of system hardening and vegetation management procedures, certain test or pilot programs in such areas, and fielding of enhanced operational and customer outage- related systems.

Wind Power Agreements. In August 2009, KU and LG&E filed a notice of intent with the Kentucky Commission indicating their intent to file an application for approval of wind power purchase contracts and cost recovery mechanisms. The contracts were executed in August 2009, and are contingent upon KU and LG&E receiving acceptable regulatory approvals. Pursuant to the proposed 20-year contracts, KU and LG&E would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In September 2009, the Companies filed an application and supporting testimony with the Kentucky Commission. In October 2009, the Kentucky Commission issued an Order denying the Companies' request to establish a surcharge for recovery of the costs of purchasing wind power. The Kentucky Commission stated that such recovery constitutes a general rate adjustment and is subject to the regulations of a base rate case. The Kentucky Commission Order currently provides for the request for approval of the wind power agreements to proceed independently from the request to recover the costs thereof via surcharges. In November 2009, KU and LG&E filed for rehearing of the Kentucky Commission's Order and requested that the matters of approval of the contract and recovery of the costs thereof remain the subject of the same proceeding. During December 2009, the Kentucky Commission issued data requests on this matter. In March 2010, the Companies filed a motion requesting a ruling on this matter during the second quarter of 2010. The Companies cannot currently predict the timing or outcome of this proceeding.

Trimble County Asset Purchase and Depreciation. KU and LG&E are currently constructing a new base- load, coal fired unit, TC2, which will be jointly owned by the Companies, together with the IMEA and the IMPA. In July 2009, the Companies notified the Kentucky Commission of the proposed sale from LG&E to KU of certain ownership interests in certain existing Trimble County generating station assets which are anticipated to provide joint or common use in support of the jointly-owned TC2 generating unit under construction at the station. The undivided ownership interests being sold are intended to provide KU an ownership interest in these common assets that is proportional to its interest in TC2 and the assets' role in supporting both TC1 and TC2. In December 2009, KU and LG&E completed the sale transaction at a price of $48 million, representing the current net book value of the assets, multiplied by the proportional interest being sold.

In August 2009, in a separate proceeding, KU and LG&E jointly filed an application with the Kentucky Commission to approve new depreciation rates for applicable TC2-related generating, pollution control and other plant equipment and assets. The filing requests common depreciation rates for the applicable jointly-owned TC2- related assets, rather than applying differing depreciation rates in place with respect to KU's and LG&E's separately-owned base-load generating assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010 and authorized KU and LG&E on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 CCN Application and Transmission Matters. An application for a CCN for construction of TC2 was approved by the Kentucky Commission in November 2005. CCNs for two transmission lines associated with TC2 were issued by the Kentucky Commission in September 2005 and May 2006. All regulatory approvals and rights of way for one transmission line have been obtained.

The CCN for the remaining line has been challenged by certain property owners in Hardin County, Kentucky. In August 2006, KU and LG&E obtained a successful dismissal of the challenge at the Franklin County Circuit Court, which ruling was reversed by the Kentucky Court of Appeals in December 2007, and the proceeding reinstated. A motion for discretionary review of that reversal was filed by KU and LG&E with the Kentucky Supreme Court and was granted in April 2009. That proceeding, which seeks reinstatement of the Circuit Court dismissal of the CCN challenge, has been fully briefed and oral argument occurred during March 2010. A ruling on the matter could occur by mid 2010.

Completion of the transmission lines are also subject to standard construction permit, environmental authorization and real property or easement acquisition procedures and certain Hardin County landowners have raised challenges to the transmission line in some of these forums as well.

During 2008, KU obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals and received a temporary stay preventing KU from accessing their properties. In April 2009, that appellate court denied KU's motion to lift the stay and issued an Order retaining the stay until a decision on the merits of the appeal. Efforts to seek reconsideration of that ruling, or to obtain intermediate review of the ruling by the Kentucky Supreme Court, were unsuccessful, and the stay remains in effect. The underlying appeal on KU's right to condemn remains pending before the Court of Appeals and oral argument on the matter is scheduled to occur during late March 2010.

Settlement discussions with the Hardin County property owners involved in the appeals of the condemnation proceedings have been unsuccessful to date. During the fourth quarter of 2008, KU and LG&E entered into settlements with certain Meade County landowners and obtained dismissals of prior litigation they had brought challenging the same transmission line.

As a result of the aforementioned unresolved litigation delays encountered in obtaining access to certain properties in Hardin County, KU has obtained easements to allow construction of temporary transmission facilities bypassing those properties while the litigated issues are resolved. In September 2009, the Kentucky Commission issued an Order stating that a CCN was necessary for two segments of the proposed temporary facilities. In December 2009, the Kentucky Commission granted the CCNs for the relevant segments and the property owners have filed various motions to intervene, stay and appeal certain elements of the Kentucky Commission's recent orders. In January 2010, in respect of two of such proceedings, the Franklin County circuit court issued Orders denying the property owners' request for a stay of construction and upholding the prior Kentucky Commission denial of their intervenor status. In parallel with, and consistent with the relevant proceedings and their status, the Company is conducting appropriate real estate acquisition and construction activities with respect to these temporary transmission facilities.

In a separate proceeding, certain Hardin County landowners have also challenged the same transmission line in federal district court in Louisville, Kentucky. In that action, the landowners claim that the U.S. Army failed to comply with certain National Historic Preservation Act requirements relating to easements for the line through Fort Knox. KU and LG&E are cooperating with the U.S. Army in its defense in this case and in October 2009, the federal court granted the defendants' motion for summary judgment and dismissed the plaintiffs' claims. During November 2009, the petitioners filed submissions for review of the decision with the 6th Circuit Court of Appeals.

KU and LG&E are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to the transmission line approval, land acquisition and permitting proceedings.

Utility Competition in Virginia. The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave customers the ability to choose their electric supplier and capped electric rates through December 2010. KU subsequently received a legislative exemption from the customer choice requirements of this law. In April 2007, however, the Virginia General Assembly amended the Virginia Electric Utility Restructuring Act, thereby terminating this competitive market and commencing re-regulation of utility rates. The new act ended the cap on rates at the end of 2008. Pursuant to this legislation, the Virginia Commission adopted regulations revising the rules governing utility rate increase applications. As of January 2009, a hybrid model of regulation is being applied in Virginia. Under this model, utility rates are reviewed every two years. KU's exemption from the requirements of the Virginia Electric Utility Restructuring Act in 1999, however, discharges the Company from the requirements of the new hybrid model of regulation. In lieu of submitting an annual information filing, the Company has the option of requesting a change in base rates to recover prudently incurred costs by filing a traditional base rate case. KU is also subject to other utility regulations in Virginia, including, but not limited to, the recovery of prudently incurred fuel costs through an annual fuel factor charge and the submission of integrated resource plans.

Market-Based Rate Authority. In July 2006, the FERC issued an Order in KU's market-based rate proceeding accepting the Company's further proposal to address certain market power issues the FERC had claimed would arise upon an exit from the MISO. In particular, the Company received permission to sell power at market-based rates at the interface of control areas in which it may be deemed to have market power, subject to a restriction that such power not be collusively re-sold back into such control areas. However, restrictions exist on sales by KU of power at market-based rates in the KU/LG&E and Big Rivers Electric Corporation control areas. In June 2007, the FERC issued Order No. 697 implementing certain reforms to market-based rate regulations, including restrictions similar to those previously in place for the Company's power sales at control area interfaces. In December 2008, the FERC issued Order No. 697-B potentially placing additional restrictions on certain power sales involving areas where market power is deemed to exist. As a condition of receiving and retaining market-based rate authority, KU must comply with applicable affiliate restrictions set forth in the FERC regulation. During September 2008, the Company submitted a regular tri-annual update filing under market-based rate regulations.

In June 2009, the FERC issued Order No. 697-C which generally clarified certain interpretations relating to power sales and purchases at control area interfaces or into control areas involving market power. In July 2009, the FERC issued an order approving the Company's September 2008 application for market-based rate authority. During July 2009, affiliates of KU completed a transaction terminating certain prior generation and power marketing activities in the Big Rivers Electric Corporation control area, which termination should ultimately allow a filing to request a determination that the Company no longer is deemed to have market power in such control area.

KU conducts certain of its wholesale power sales activities in accordance with existing market-based rate authority principles and interpretations. Future FERC proceedings relating to Orders 697 or market-based rate authority could alter the amount of sales made at market-based versus cost-based rates. The Company's sales under market-based rate authority totaled less than $1 million for the year ended December 31, 2009.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various Regional Reliability Organizations ("RROs") by the NERC, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. KU is a member of the SERC Reliability Corporation ("SERC"), which acts as KU's RRO. During May 2008, the SERC and KU agreed to a settlement involving penalties totaling less than $1 million related to KU's February 2008 self-report concerning possible violations of certain existing mitigation plans relating to reliability standards. During December 2009, the SERC and KU agreed to a settlement involving penalties totaling less than $1 million concerning a June 2008 self-report by KU relating to three other standards and an October 2008 self-report relating to an additional standard. During December 2009, KU submitted a self-report relating to an additional standard. SERC proceedings for the December 2009 self-report are in the early stages and therefore the outcome is unable to be determined. Mandatory reliability standard settlements commonly include other non-penalty elements, including compliance steps and mitigation plans. Settlements with the SERC proceed to NERC and FERC review before becoming final. While KU believes itself to be in compliance with the mandatory reliability standards, the Company cannot predict the outcome of other analyses, including on-going SERC or other reviews described above.

Integrated Resource Planning. Integrated resource planning ("IRP") regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2008, KU and LG&E filed their 2008 joint IRP with the Kentucky Commission. The IRP provides historical and projected demand, resource and financial data, and other operating performance and system information. The Kentucky Commission issued a staff report and Order closing this proceeding in December 2009. Pursuant to the Virginia Commission's December 2008 Order, KU filed its IRP in July 2009. The filing consisted of the 2008 Joint IRP filed by KU and LG&E with the Kentucky Commission along with additional data. The Virginia Commission has not established a procedural schedule for this proceeding.

PUHCA 2005. E.ON, KU's ultimate parent, is a registered holding company under PUHCA 2005. E.ON, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries, are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non- power goods and services. KU believes that it has adequate authority, including financing authority, under existing FERC orders and regulations to conduct its business and will seek additional authorization when necessary.

EPAct 2005. The EPAct 2005 was enacted in August 2005. Among other matters, this comprehensive legislation contains provisions mandating improved electric reliability standards and performance; granting enhanced civil penalty authority to the FERC; providing economic and other incentives relating to transmission, pollution control and renewable generation assets; increasing funding for clean coal generation incentives; repealing the Public Utility Holding Company Act of 1935; enacting PUHCA 2005 and expanding FERC jurisdiction over public utility holding companies and related matters via the Federal Power Act and PUHCA 2005.

In February 2006, the Kentucky Commission initiated an administrative proceeding to consider the requirements of the EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnections. EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252 standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254 standards within one year after the enactment of EPAct 2005. Following a public hearing with all Kentucky jurisdictional electric utilities, in December 2006, the Kentucky Commission issued an Order in this proceeding indicating that the EPAct 2005 Section 1252 and Section 1254 standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities are required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU for implementation within approximately eight months, for its large commercial and industrial customers. The tariff was filed in October 2008, with an effective date of December 1, 2008. KU files annual reports on the program within 90 days of each plan year-end for the 3-year pilot period.

Green Energy Riders. In February 2007, KU and LG&E filed a Joint Application and Testimony for Proposed Green Energy Riders. In May 2007, a Kentucky Commission Order was issued authorizing KU to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits. During November 2009, KU and LG&E filed an application to both continue and modify the existing Green Energy Programs and requested a Kentucky Commission Order by March 2010.

Home Energy Assistance Program. In July 2007, KU filed an application with the Kentucky Commission for the establishment of a Home Energy Assistance program. During September 2007, the Kentucky Commission approved the five-year program as filed, effective in October 2007. The program terminates in September 2012, and is funded through a $0.10 per month meter charge. Effective February 6, 2009, as a result of the settlement agreement in the 2008 base rate case, the program is funded through a $0.15 per month meter charge.

Collection Cycle Revision. As part of its base rate case filed on July 29, 2008, LG&E proposed to change the due date for customer bill payments from 15 days to 10 days to align its collection cycle with KU. In addition, KU proposed to include a late payment charge if payment is not received within 15 days from the bill issuance date to align with LG&E. The settlement agreement approved in the rate case in February 2009, changed the due date for customer bill payments to 12 days after bill issuance for both KU and LG&E, and permitted KU's implementation of a late payment charge if payment is not received within 15 days from the bill issuance date.

Depreciation Study. In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The approved settlement agreement in the rate case established new depreciation rates effective February 2009. KU also filed the depreciation study with the Virginia

Commission which approved the implementation of the new depreciation rates effective February 2009. Approval by the Virginia Commission does not preclude the rates from being raised as an issue by any party in KU's current base rate case in Virginia.

Brownfield Development Rider Tariff. In March 2008, KU received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider permits special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Interconnection and Net Metering Guidelines. In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented proposed interconnection guidelines to the Kentucky Commission in October 2008. In a January 2009 Order, the Kentucky Commission issued the Interconnection and Net Metering Guidelines — Kentucky that were developed by all parties to the proceeding. KU does not expect any financial or other impact as a result of this Order. In April 2009, KU filed revised net metering tariffs and application forms pursuant to the Kentucky Commission's Order. The Kentucky Commission issued an Order in April 2009, which suspended for five months all net metering tariffs filed by the jurisdictional electric utilities. This suspension was intended to allow sufficient time for review of the filed tariffs by the Kentucky Commission Staff and intervening parties. In June 2009, the Kentucky Commission Staff held an informal conference with the parties to discuss issues related to the net metering tariffs filed by KU. Following this conference, the intervenors and KU resolved all issues and KU filed revised net metering tariffs with the Kentucky Commission. In August 2009, the Kentucky Commission issued an Order approving the revised tariffs.

EISA 2007 Standards. In November 2008, the Kentucky Commission initiated an administrative proceeding to consider new standards as a result of the Energy Independence and Security Act of 2007 ("EISA 2007"), part of which amends the Public Utility Regulatory Policies Act of 1978 ("PURPA"). There are four new PURPA standards and one non-PURPA standard applicable to electric utilities. The proceeding also considers two new PURPA standards applicable to natural gas utilities. EISA 2007 requires state regulatory commissions and nonregulated utilities to begin consideration of the rate design and smart grid investments no later than December 19, 2008, and to complete the consideration by December 19, 2009. The Kentucky Commission established a procedural schedule that allowed for data discovery and testimony through July 2009. A public hearing has not been scheduled in this matter. In October 2009, the Kentucky Commission held an informal conference for the purpose of discussing issues related to the standard regarding the consideration of Smart Grid investments.

Note 3 — Financial Instruments

The cost and estimated fair values of KU's non-trading financial instruments as of December 31 follow:

	2009		2008	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
	(In millions)			
Long-term debt (including current portion of $228 million)	$ 351	$ 351	$ 351	$ 349
Long-term debt from affiliate (including current portion of $33 million)	$1,331	$1,401	$1,181	$1,117

The long-term debt valuations reflect prices quoted by dealers. The fair value of the long-term debt from affiliate is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates. The current market values are determined based on quotes from investment banks that are actively involved in capital markets for utilities and factor in KU's credit ratings and default risk. The fair values of cash and cash equivalents, accounts receivable, cash surrender value of key man life insurance, accounts payable and notes payable are substantially the same as their carrying values.

KU is subject to the risk of fluctuating interest rates in the normal course of business. The Company's policies allow the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2009, a 100 basis point change in the benchmark rate on KU's variable rate debt would impact pre- tax interest expense by $4 million annually. Although the Company's policies allow for the use of interest rate swaps, as of December 31, 2008 and 2009, KU had no interest rate swaps outstanding.

The Company is subject to interest rate and commodity price risk related to on-going business operations. It currently manages these risks using derivative financial instruments including swaps and forward contracts.

KU has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC, as follows:

- Level 1 — Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 — Include other inputs that are directly or indirectly observable in the marketplace.
- Level 3 — Unobservable inputs which are supported by little or no market activity.

Energy Trading and Risk Management Activities. KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to manage price risk and are accounted for as non-hedging derivatives on a mark-to-market basis in accordance with the derivatives and hedging guidance of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Inter- continental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs include prices quoted by brokers or observable inputs other than quoted prices, such as one-sided bids or offers as of the balance sheet date. Using these valuation methodologies, these contracts are considered level 2 based on measurement criteria in the fair value measurements and disclosures guidance of the FASB ASC. Quotes are verified quarterly using an independent pricing source of actual transactions. Quotes for combined off-peak and weekend timeframes are allocated between the two timeframes based on their historically proportionate ratios to the integrated cost. No other adjustments are made to the forward prices. No changes to valuation techniques for energy trading and risk management activities occurred during 2009, 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, KU seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, KU assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At December 31, 2009, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company has reserved against counterparty credit risk based on the counterparty's credit rating and applying historical default rates within varying credit ratings over time provided by S&P or Moody's. At December 31, 2009 and 2008, credit reserves related to the energy trading and risk management contracts were less than $1 million.

The net volume of electricity based financial derivatives outstanding at December 31, 2009 and 2008, was 315,600 Mwhs and 146,000 Mwhs, respectively. All the volume outstanding at December 31, 2009 will settle in 2010.

The following table sets forth by level within the fair value hierarchy, KU's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. Cash collateral related to the energy trading and
risk management contracts was less than $1 million at December 31, 2009 and 2008. Cash collateral related to the energy

trading and risk management contracts is categorized as other accounts receivable and is a level 1 measurement based on the funds being held in liquid accounts. Energy trading and risk management contracts are considered level 2 based on measurement criteria in the fair value measurements and disclosures guidance of the FASB ASC. Financial assets as of December 31, 2009 and financial liabilities as of December 31, 2009 and 2008, arising from energy trading and risk management contracts accounted for at fair value total less than $1 million and use level 2 measurements. There are no level 3 measurements for the periods ending December 31, 2009 and 2008.

December 31, 2008	Level 1	Level 2	Total
Financial Assets:			
Energy trading and risk management contracts	$—	$1	$1
Total Financial Assets	$—	$1	$1

The Company does not net collateral against derivative instruments.

Certain of the Company's derivative instruments contain provisions that require the Company to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. At December 31, 2009, there are no energy trading and risk management contracts with credit risk related contingent features that are in a liability position, and no collateral posted in the normal course of business. At December 31, 2009, a one notch downgrade of the Company's credit rating would have no effect on the energy trading and risk management contracts or collateral required as a result of these contracts.

The table below shows the fair value and balance sheet location of derivatives not designated as hedging instruments as of December 31, 2008:

December 31, 2008				
Energy trading and risk management contracts (current)	Other current assets	$1	Other current liabilities	$—
Total		$1		$—

Financial assets and liabilities as of December 31, 2009 arising from energy trading and risk management contracts accounted for at fair value total less than $1 million.

KU manages the price risk of its estimated future excess economic generation capacity using market-traded forward financial contracts. Hedge accounting treatment has not been elected for these transactions, and therefore gains and losses are shown in the statements of income.

The following tables present the effect of derivatives not designated as hedging instruments on income for the years ended December 31, 2009 and 2008:

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives (In millions)
December 31, 2009		
Energy trading and risk management contracts (unrealized)	Electric revenues	$(1)
Total		$(1)
December 31, 2008		
Energy trading and risk management contracts (unrealized)	Electric revenues	$ 1
Total		$ 1

Unrealized gains and losses were less than $1 million for the year ended December 31, 2007. Net realized gains and losses were less than $1 million for the years ended December 31, 2009, 2008, and 2007.

Note 4 — Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

KU's customer receivables and revenues arise from deliveries of electricity to approximately 515,000 customers in over 600 communities and adjacent suburban and rural areas in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. For the years ended December 31, 2009, 2008 and 2007, 100% of total revenue was derived from electric operations. During 2009, the Company's 10 largest customers accounted for less than 15% of electric volumes.

Effective August 4, 2009, the Company and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement. The agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. KU and employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2008. This agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. The employees represented by these two bargaining units comprise approximately 15% of the Company's workforce at December 31, 2009.

Note 5 — Pension and Other Postretirement Benefit Plans

KU employees benefit from both funded and unfunded non-contributory defined benefit pension plans and other postretirement benefit plans that together cover employees hired by December 31, 2005. Employees hired after this date participate in the Retirement Income Account ("RIA"), a defined contribution plan. The Company makes an annual lump sum contribution to the RIA, based on years of service and a percentage of covered compensation. The health care plans are contributory with participants' contributions adjusted annually. The Company uses December 31 as the measurement date for its plans.

Obligations and Funded Status. The following tables provide a reconciliation of the changes in the defined benefit plans' obligations and the fair value of assets for the two-year period ending December 31, 2009, and the funded status for the plans as of December 31:

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			
Change in benefit obligation				
Benefit obligation at beginning of year	$306	$ 284	$ 75	$ 76
Service cost	6	5	2	1
Interest cost	18	18	4	5
Benefits paid, net of retiree contributions	(18)	(18)	(5)	(3)
Actuarial (gain)/loss and other	4	17	4	(4)
Benefit obligation at end of year	$316	$ 306	$ 80	$ 75
Change in plan assets				
Fair value of plan assets at beginning of year	$183	$ 264	$ 12	$ 13
Actual return on plan assets	41	(61)	3	(3)
Employer contributions	13	—	7	5
Benefits paid, net of retiree contributions	(18)	(18)	(5)	(3)
Administrative expenses and other	—	(2)	—	—
Fair value of plan assets at end of year	$219	$ 183	$ 17	$ 12
Funded status at end of year	$ (97)	$(123)	$(63)	$(63)

Amounts Recognized in Statement of Financial Position. The following tables provide the amounts recognized in the balance sheets and information for plans with benefit obligations in excess of plan assets as of December 31:

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			
Regulatory assets	$105	$ 137	$ —	$ —
Regulatory liabilities	—	—	(9)	(10)
Accrued benefit liability (non-current)	(97)	(123)	(63)	(63)

Amounts recognized in regulatory assets and liabilities consist of:

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			
Transition obligation	$ —	$ —	$ 3	$ 4
Prior service cost	5	5	2	2
Accumulated (gain)/loss	100	132	(14)	(16)
Total regulatory assets (liabilities)	$105	$137	$ (9)	$(10)

Additional year-end information for plans with accumulated benefit obligations in excess of plan assets:

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			
Benefit obligation	$316	$306	$80	$75
Accumulated benefit obligation	268	261	—	—
Fair value of plan assets	219	183	17	12

For discussion of the pension and postretirement regulatory assets, see Note 2, Rates and Regulatory Matters.

The amounts recognized in regulatory assets and liabilities for the years ended December 31, are composed of the following:

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			
Prior service cost arising during the period	$ —	$ —	$—	$ 1
Net loss/(gain) arising during the period	(22)	101	2	—
Amortization of prior service (cost)/credit	(1)	(1)	—	(1)
Amortization of transitional (obligation)/asset	—	—	(1)	(1)
Amortization of gain/(loss)	(9)	—	—	—
Total amounts recognized in regulatory assets & liabilities	$(32)	$100	$ 1	$ (1)

Components of Net Periodic Benefit Cost. The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both KU employees and E.ON U.S. Services' employees, who provide services to the utility. The E.ON U.S. Services' costs that are allocated to KU are approximately 49%, 46% and 45% of E.ON U.S. Services' total cost for 2009, 2008 and 2007, respectively.

	Pension Benefits								
	KU 2009	E.ON U.S. Services Allocation to KU 2009	Total KU 2009	KU 2008	E.ON U.S. Services Allocation to KU 2008	Total KU 2008	KU 2007	E.ON U.S. Services Allocation to KU 2007	Total KU 2007
	(In millions)								
Service cost	$ 6	$ 5	$ 11	$ 6	$ 4	$ 10	$ 6	$ 4	$ 10
Interest cost	18	7	25	18	6	24	17	5	22
Expected return on plan assets	(15)	(4)	(19)	(21)	(5)	(26)	(21)	(5)	(26)
Amortization of prior service costs	1	1	2	1	1	2	1	1	2
Amortization of actuarial loss	9	2	11	—	—	—	2	1	3
Benefit cost at end of year	$ 19	$11	$ 30	$ 4	$ 6	$ 10	$ 5	$ 6	$ 11

	Other Postretirement Benefits								
	KU 2009	E.ON U.S. Services Allocation to KU 2009	Total KU 2009	KU 2008	E.ON U.S. Services Allocation to KU 2008	Total KU 2008	KU 2007	E.ON U.S. Services Allocation to KU 2007	Total KU 2007
	(In millions)								
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	5	—	5	5	—	5	5	—	5
Expected return on plan assets	(1)	—	(1)	(1)	—	(1)	(1)	—	(1)
Amortization of transitional obligation	1	—	1	1	—	1	1	—	1
Benefit cost at end of year	$ 6	$ 1	$ 7	$ 6	$ 1	$ 7	$ 6	$ 1	$ 7

The estimated amounts that will be amortized from regulatory assets and liabilities into net periodic benefit cost in 2010 are shown in the following table:

	Pension Benefits	Other Postretirement Benefits
	(In millions)	
Regulatory assets/liabilities:		
Net actuarial loss	$ 6	$—
Prior service cost	1	1
Transition obligation	—	1
Total regulatory assets/liabilities amortized during 2010	$ 7	$ 2

The assumptions used in the measurement of KU's pension benefit obligation are shown in the following table:

	2009	2008
Weighted-average assumptions as of December 31:		
Discount rate	6.13%	6.25%
Rate of compensation increase	5.25%	5.25%

The discount rates were determined by the December 28, 2009, Mercer Pension Discount Yield Curve. These discount rates were then lowered by 8 basis points for the average change in 4 bond indices, Citigroup High Grade Credit Index AAA/AA 10+ years, Barclays Capital US Long Credit AA, Merrill Lynch US Corporate AA-AAA rated 10+ years and Merrill Lynch US Corporate AA rated 15+ years, for the period from December 28, 2009 to December 31, 2009.

The assumptions used in the measurement of KU's net periodic benefit cost are shown in the following table:

	2009	2008	2007
Discount rate	6.25%	6.66%	5.96%
Expected long-term return on plan assets	8.25%	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, KU considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio.

The following describes the effects on pension benefits by changing the major actuarial assumptions discussed above:

- A 1% change in the assumed discount rate could have an approximate $34 million positive or negative impact to the 2009 accumulated benefit obligation and an approximate $45 million positive or negative impact to the 2009 projected benefit obligation.

- A 25 basis point change in the expected rate of return on assets would have resulted in less than a $1 million positive or negative impact on 2009 pension expense.

Assumed Health Care Cost Trend Rates. For measurement purposes, an 8% annual increase in the per capita cost of covered health care benefits was assumed for 2009. The rate was assumed to decrease gradually to 4.5% by 2029 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in assumed health care cost trend rates would have resulted in an increase or decrease of less than
$1 million on the 2009 total of service and interest costs components and an increase or decrease of $4 million in year-end 2009 postretirement benefit obligations.

Expected Future Benefit Payments and Medicare Subsidy Receipts. The following list provides the amount of expected future benefit payments, which reflect expected future service and the estimated gross amount of Medicare subsidy receipts:

	Pension Benefits	Other Postretirement Benefits	Medicare Subsidy Receipts
		(In millions)	
2010	$17	$ 6	$ 1
2011	17	6	—
2012	17	6	1
2013	17	6	—
2014	17	7	1
2015-19	97	37	3

Plan Assets. The following table shows the plans' weighted-average asset allocation by asset category at December 31:

Pension Plans	**Target Range**	**2009**	**2008**
Equity securities	45% - 75%	59%	55%
Debt securities	30% - 50%	40	43
Other	0% - 10%	1	2
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the fund and maximize investment earnings. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Barclays Capital Aggregate and Barclays Capital U.S. Long Government/Credit Bond Index in proportions equal to the targeted asset allocation.

Evaluation of performance focuses on a long-term investment time horizon of at least three to five years or a complete market cycle. The assets of the pension plans are broadly diversified within different asset classes (equities, fixed income securities and cash equivalents).

To minimize the risk of large losses in a single asset class, no more than 5% of the portfolio will be invested in the securities of any one issuer with the exclusion of the U.S. government and its agencies. The equity portion of the fund is diversified among the market's various subsections to diversify risk, maximize returns and avoid undue exposure to any single economic sector, industry group or individual security. The equity subsectors include, but are not limited to, growth, value, small capitalization and international.

In addition, the overall fixed income portfolio may have an average weighted duration, or interest rate sensitivity which is within +/- 20% of the duration of the overall fixed income benchmark. Foreign bonds in the aggregate shall not exceed 10% of the total fund. The portfolio may include a limited investment of up to 20% in below investment grade securities provided that the overall average portfolio quality remains "AA" or better. The below investment grade securities include, but are not limited to, medium-term notes, corporate debt, non-dollar and emerging market debt and asset backed securities. The cash investments should be in securities that are either short maturities (not to exceed 180 days) or readily marketable with modest risk.

Derivative securities are permitted only to improve the portfolio's risk/return profile, to modify the portfolio's duration or to reduce transaction costs and must be used in conjunction with underlying physical assets in the portfolio. Derivative securities that involve speculation, leverage, interest rate anticipation, or any undue risk whatsoever are not deemed appropriate investments.

The investment objective for the postretirement benefit plan is to provide current income consistent with stability of principal and liquidity while maintaining a stable net asset value of $1.00 per share. The postretirement funds are invested in a prime cash money market fund that invests primarily in a portfolio of short-term, high-quality fixed income securities issued by banks, corporations and the U.S. government.

KU has classified plan assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC. See Note 3 of the Notes to Financial Statements.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

A description of the valuation methodologies used to measure plan assets at fair value is provided below:

Money Market Fund: These investments are public investment vehicles valued using $1 for the net asset value. The money market funds are classified within level 2 of the valuation hierarchy.

Common/Collective Trusts: Valued based on the beginning of year value of the plan's interests in the trust plus actual contributions and allocated investment income (loss) less actual distributions and allocated administrative expenses. Quoted market prices are used to value investments in the trust, with the exception of the Group Annuity Contract ("GAC"). The fair value of certain other investments for which quoted market prices are not available are valued based on yields currently available on comparable securities of issuers with similar credit ratings. The common/collective trusts are classified within level 2 of the valuation hierarchy.

The preceding methods described may produce a fair value that may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date. There were no changes in the plan's valuation methodologies during 2009.

The following table sets forth, by level within the fair value hierarchy, the plan's assets at fair value as of December 31, 2009:

	Level 2 (Millions)
Money Market Fund	$ 2
Common/Collective Trusts	186
Total investments at fair value	$188

There are no assets categorized as level 1 or level 3.

The GAC is an immediate participation guarantee contract. In accordance with the plan accounting guidance of the FASB ASC, the cost incurred to purchase the GAC prior to March 20, 1992, is permitted to be carried at contract value, since it is a contract with an insurance company and therefore is excluded from the table above. The cost incurred to fund the GAC after March 20, 1992, is carried at contract value in accordance with the plan accounting guidance of the FASB ASC, since it is a contract that incorporates mortality and morbidity risk. Contract value represents cost plus interest income less distributions for benefits and administrative expenses.

Contributions. KU made a discretionary contribution to the pension plan of $13 million in April 2009 and $13 million in January 2007. The Company also made contributions to other postretirement benefit plans of $7 million, $5 million and $6 million in 2009, 2008 and 2007, respectively. The amount of future contributions to the pension plan will depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. In January 2010, KU made a discretionary contribution to the pension plan of $13 million and anticipates making voluntary contributions to fund Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Pension Legislation. The Pension Protection Act of 2006 was enacted in August 2006. New rules regarding funding of defined benefit plans are generally effective for plan years beginning in 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate full funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions;
(iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains a number of provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters. The Company's plan met the minimum funding requirements as defined by the Pension Protection Act of 2006 for years ended December 31, 2009 and 2008.

Thrift Savings Plans. KU has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. KU makes contributions to the plan by matching a portion of the employee contributions. The costs of this matching were $3 million in 2009 and 2008, and $2 million in 2007.

KU also makes contributions to retirement income accounts within the thrift savings plans for certain employees not covered by noncontributory defined benefit pension plans. These employees consist mainly of those hired after December 31, 2005. The Company makes these contributions based on years of service and the employees' wage and salary levels, and it makes them in addition to the matching contributions discussed above. The amounts contributed by the Company under this arrangement equaled less than $1 million in 2009, 2008 and 2007.

Note 6 — Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, E.ON US Investments Corp., for each tax period. Each subsidiary of the consolidated tax group, including KU, calculates its separate income tax for each period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. The Company also files income tax returns in various state jurisdictions. While 2006 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2006-2007 have been received from the IRS, effectively closing these years to additional audit adjustments. Adjustments to these tax years were previously recorded in the financial statements. Tax years 2007 and 2008 were examined under an IRS pilot program named "Compliance Assurance Process" ("CAP"). This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed. KU had no adjustments for the 2007 federal return. Areas remaining under examination for 2008 include bonus depreciation and the Company's application for a change in repair deductions. No net material adverse impact is expected from these remaining areas.

Additions and reductions of uncertain tax positions during 2009, 2008 and 2007 were less than $1 million. Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million and are based on the expiration of the audit periods as defined in the statutes. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of December 31, 2009, 2008 and 2007. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. KU records the interest as interest expense and penalties as operating expenses in the income statement and accrued expenses in the balance sheets, on a pre-tax basis. No penalties were accrued by the Company through December 31, 2009.

Components of income tax expense are shown in the table below:

		2009	2008	2007
			(In millions)	
Current	— federal	$ (5)	$ 46	$28
	— state	1	10	13
Deferred	— federal — net	43	(10)	(5)
	— state — net	7	(3)	(1)
Investment tax credit — deferred		21	25	43
Amortization of investment tax credit		—	—	(1)
Total income tax expense		$67	$ 68	$77

Deferred federal and state income tax expense increased in 2009, compared to 2008, due primarily to temporary differences related to storm costs and depreciation. The temporary differences also resulted in an offsetting decrease to current federal and state taxes in 2009. Current federal income tax expense increased in 2008, compared to 2007, and investment tax credit — deferred decreased primarily due to claiming $18 million less in investment tax credits in 2008. Current state income tax decreased due to coal credits claimed in 2008. Deferred federal income tax expense decreased in 2008 primarily due to adjusting prior year estimates to actual based on the filed tax return.

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit. KU's portion of the TC2 tax credit will be approximately $101 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $21 million, $25 million and $43 million in 2009, 2008 and 2007, respectively, decreasing current federal income taxes. The amount claimed through 2009 is all that KU is allowed to claim. KU has reached the maximum credit of $101 million. In addition, a full depreciation basis adjustment is required for the amount of the credit. The income tax expense impact from amortizing these credits will begin when the facility is placed in service.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. During 2008 and 2009, the plaintiffs submitted amended complaints alleging additional claims for relief. In October 2009, the plaintiffs filed a motion for a preliminary injunction seeking temporary implementation of certain elements of the requested relief. The Company is not currently a party to this proceeding and is not able to predict the ultimate outcome of this matter.

Components of net deferred tax liabilities included in the balance sheets are shown below:

	2009	2008
	(In millions)	
Deferred tax liabilities:		
Depreciation and other plant-related items	$303	$284
Regulatory assets and other	69	40
Total deferred tax liabilities	372	324
Deferred tax assets:		
Income taxes due to customers	4	6
Pensions and related benefits	17	19
Liabilities and other	18	22
Total deferred tax assets	39	47
Net deferred income tax liability	$333	$277
Balance sheet classification		
Current assets	$ (3)	$ (2)
Non-current liabilities	336	279
Net deferred income tax liability	$333	$277

The Company expects to have adequate levels of taxable income to realize its recorded deferred tax assets.

A reconciliation of differences between the statutory U.S. federal income tax rate and KU's effective income tax rate follows:

	2009	2008	2007
Statutory federal income tax rate	35.0%	35.0%	35.0%
State income taxes, net of federal benefit	2.7	2.6	3.4
Reduction of income tax reserve	—	(0.2)	(0.4)
Qualified production activities deduction	(0.3)	(1.1)	(1.2)
Dividends received deduction related to EEI investment	(1.5)	(4.2)	(2.9)
Reversal of excess deferred taxes	(0.9)	(0.6)	(0.8)
Other differences	(1.5)	(1.4)	(1.5)
Effective income tax rate	33.5%	30.1%	31.6%

The effective income tax rate increased from 2008 to 2009 primarily due to a $15 million decrease in 2009 dividends received from Electric Energy Inc., reducing the dividends received deduction. The effective income tax rate decreased from 2007 to 2008 primarily due to increased dividends from its investment in EEI.

Note 7 — Long-Term Debt

As of December 31, 2009 and 2008, long-term debt and the current portion of long-term debt consist primarily of pollution control bonds and long-term loans from affiliated companies as summarized below.

	Stated Interest Rates	Maturities	Principal Amounts (In millions)
Outstanding at December 31, 2009:			
Noncurrent portion	Variable — 7.035%	2011-2037	$1,421
Current portion	Variable — 4.240%	2010-2034	$ 261
Outstanding at December 31, 2008:			
Noncurrent portion	Variable — 7.035%	2010-2037	$1,304
Current portion	Variable	2023-2034	$ 228

Long-term debt includes $228 million of pollution control bonds that are classified as current portion because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Carroll County 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A. Maturity dates for these bonds range from 2023 to 2034. The average annualized interest rate for these bonds during 2009, 2008 and 2007, was 0.61%, 1.75% and 3.72%, respectively.

Pollution control bonds are obligations issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. The loan agreement is an unsecured obligation of the Company. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) were held in trust pending expenditure for qualifying assets. At December 31, 2009, KU had no bond proceeds in trust included in restricted cash on the balance sheet. At December 31, 2008, the Company had $9 million of bond proceeds in trust included in restricted cash in the balance sheets.

Several of the pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At December 31, 2009, the Company had an aggregate $351 million of outstanding pollution control indebtedness, of which $96 million is in the form of insured auction rate securities wherein interest rates are reset every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. During 2008, interest rates increased, and the Company experienced “failed auctions” when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. During 2009, 2008 and 2007, the average rate on the auction rate bonds was 0.44%, 4.50% and 3.96%, respectively. The instruments governing these auction rate bonds permit KU to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In June 2009, S&P downgraded the credit rating of Ambac from “A” to “BBB”. As a result, S&P downgraded the rating on certain bonds in June 2009. The S&P rating of these bonds is now based on the rating of the Company rather than the rating of Ambac since the Company's rating is higher. The following table presents the bonds downgraded:

Tax Exempt Bond Issues	Principal	Bond Rating Moody's 2009	Moody's 2008	S&P 2009	S&P 2008
	($ in millions)				
Carroll County 2002 Series C	$96	A2	A2	BBB+	A
Carroll County 2007 Series A	$18	A2	A2	BBB+	A
Trimble County 2007 Series A	$ 9	A2	A2	BBB+	A

During 2008, KU converted several series of its pollution control bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. In connection with these conversions, the Company purchased some of the bonds from the remarketing agent. The bonds that were repurchased from the remarketing agent in 2008 were either defeased or remarketed during 2008.

As of December 31, 2009, KU had no remaining repurchased bonds. During 2008, KU refinanced and remarketed $63 million and refinanced $17 million of pollution control bonds that had been previously repurchased by the Company.

All of KU's first mortgage bonds were released and terminated in February 2007. Under the provisions for certain of KU's variable-rate pollution control bonds, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt in the balance sheets. The average annualized interest rate for these bonds during 2009, 2008 and 2007 was 0.61%, 1.75% and 3.72%, respectively.

There were no redemptions or maturities of long-term debt for 2009. Redemptions and maturities of long-term debt for 2008 and 2007 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
		($ in millions)			
2008	Pollution control bonds	$13	Variable	Secured	2035
2008	Pollution control bonds	$13	Variable	Secured	2035
2008	Pollution control bonds	$17	Variable	Secured	2036
2008	Pollution control bonds	$17	Variable	Secured	2036
2007	Pollution control bonds	$54	Variable	Secured	2024
2007	First mortgage bonds	$54	7.92%	Secured	2007

Issuances of long-term debt for 2009, 2008 and 2007 are summarized below:

Year	Description	Principal Amount ($ in millions)	Rate	Secured/ Unsecured	Maturity
2009	Due to Fidelia	$ 50	4.445%	Unsecured	2019
2009	Due to Fidelia	$ 50	4.81%	Unsecured	2019
2009	Due to Fidelia	$ 50	5.28%	Unsecured	2017
2008	Due to Fidelia	$ 75	7.035%	Unsecured	2018
2008	Pollution control bonds	$ 78	Variable	Unsecured	2032
2008	Due to Fidelia	$ 50	6.16%	Unsecured	2018
2008	Due to Fidelia	$ 50	5.645%	Unsecured	2018
2008	Due to Fidelia	$ 75	5.85%	Unsecured	2023
2007	Pollution control bonds	$ 54	Variable	Unsecured	2034
2007	Pollution control bonds	$ 18	Variable	Unsecured	2026
2007	Pollution control bonds	$ 9	Variable	Unsecured	2037
2007	Due to Fidelia	$ 53	5.69%	Unsecured	2022
2007	Due to Fidelia	$ 75	5.86%	Unsecured	2037
2007	Due to Fidelia	$ 50	5.98%	Unsecured	2017
2007	Due to Fidelia	$100	5.96%	Unsecured	2028
2007	Due to Fidelia	$ 70	5.71%	Unsecured	2019
2007	Due to Fidelia	$100	5.45%	Unsecured	2014

In February 2007, KU completed a series of financial transactions impacting its periodic reporting require- ments. The $54 million Pollution Control Series 10 bond was refinanced and replaced with a new unsecured tax- exempt bond of the same amount maturing in 2034. The $53 million Series P bond was defeased and replaced with an intercompany loan totaling $53 million from Fidelia. In conjunction with the defeasance, the Company terminated the related interest rate swap. Fidelia also agreed to eliminate the second lien on its two secured loans. Pursuant to the terms of the remaining tax-exempt bonds, the first mortgage bonds were cancelled and the underlying lien on substantially all of KU’s assets was released following the completion of these steps. KU no longer has any secured debt and is no longer subject to periodic reporting under the Securities Exchange Act of 1934.

In October 2008, the Company issued Carroll County 2008 Series A tax exempt bonds in the amount of $78 million. The new bonds mature on February 1, 2032, and bear interest at a variable rate. The new bonds refinance four existing bonds (Carroll County 2005 Series A and B — $13 million each and the Carroll County 2006 Series A and C — $17 million each), and include $18 million of new funding. The proceeds were held in escrow pending incurrence of qualifying expenditures, but have now been used.

In December 2008, KU converted the interest rate mode of the Carroll County 2006 Series B to a weekly mode from an auction mode. The bonds along with the Carroll County 2004 Series A, the Mercer County 2000 Series A, and the Carroll County 2008 Series A, were issued with the enhancement of a letter of credit. The bonds have been reclassified as current portion of long-term debt because investors can put the bonds back to the Company on a weekly basis.

As of December 31, 2009, $1,331 million of unsecured notes payable was outstanding to the Company’s affiliate, Fidelia, with interest rates ranging from 4.24% to 7.04% and maturities ranging from 2010 to 2037.

Long-term debt maturities for KU are shown in the following table:

	(In millions)
2010	$ 33
2011	—
2012	50
2013	175
2014	100
Thereafter	1,324(a)
Total	$1,682

(a) Includes long-term debt of $228 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. Maturity dates for these bonds range from 2023 to 2034.

Note 8 — Notes Payable and Other Short-Term Obligations

KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) up to $400 million. Details of the balances are as follows:

	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
		($ in millions)		
December 31, 2009	$400	$45	$355	0.20%
December 31, 2008	$400	$16	$384	1.49%

E.ON U.S. maintains revolving credit facilities totaling $313 million at December 31, 2009 and 2008, to ensure funding availability for the money pool. At December 31, 2009 and 2008, one facility, totaling $150 million, is with E.ON North America, Inc., while the remaining line, totaling $163 million, is with Fidelia; both are affiliated companies. The balances are as follows:

	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
		($ in millions)		
December 31, 2009	$313	$276	$37	1.25%
December 31, 2008	$313	$299	$14	2.05%

As of December 31, 2009, the Company maintained a bilateral line of credit, with an unaffiliated financial institution, totaling $35 million which matures in June 2012. At December 31, 2009, there was no balance outstanding under this facility.

The covenants under this revolving line of credit include the following:

- The debt/total capitalization ratio must be less than 70%
- E.ON must own at least 66.667% of voting stock of KU directly or indirectly
- The corporate credit rating of the Company must be at or above BBB- and Baa3 as determined by S&P and Moody's
- A limitation on disposing of assets aggregating more than 15% of total assets as of December 31, 2006

KU was in compliance with these covenants at December 31, 2009.

In October 2008, KU closed on a $78 million bilateral line of credit which had a 364 day maturity. This facility was terminated in December 2008 and replaced by four new letter of credit facilities to allow issuance of letters of credit totaling $198 million to support tax-exempt bonds totaling $195 million of the $228 million of bonds that can be put back to the Company. Should the holders elect to put the bonds back and they cannot be remarketed, the letter of credit would fund the investor's payment. The expiration date for the letters of credit has been extended to December 2010. The reimbursement agreements are identical and contain the following covenants:

- E.ON must own 75% of voting stock of KU directly or indirectly
- A limitation on disposing of assets aggregating more than 20% of total assets as of most recent quarter-end.

At December 31, 2009, KU had no remaining capacity for letters of credit under these facilities and was in compliance with these covenants.

Note 9 — Commitments and Contingencies

Operating Leases. KU leases office space, office equipment, plant equipment, real estate, railcars, tele- communications and vehicles and accounts for these leases as operating leases. In addition, KU reimburses LG&E for a portion of the lease expense paid by LG&E for KU's usage of office space leased by LG&E. Total lease expense was $10 million, $9 million and $6 million for 2009, 2008 and 2007, respectively. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2009, are shown in the following table:

	(In millions)
2010	$ 7
2011	6
2012	5
2013	4
2014	4
Thereafter	3
Total	$29

Owensboro Contract Litigation. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit which was removed to the U.S. District Court for the Western District of Kentucky, against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. The dispute involved interpretational differences regarding issues under the OMU Agreement, including various payments or charges between KU and OMU and rights concerning excess power, termination and emissions allowances. In July 2005, the court issued a summary judgment ruling upholding OMU's contractual right to terminate the OMU agreement in May 2010.

In September and October 2008, the court granted rulings on a number of summary judgment petitions in the Company's favor. The summary judgment rulings resulted in the dismissal of all of OMU's remaining claims against the Company. The trial on KU's counterclaim occurred during October and November 2008. During February 2009, the court issued orders on the matters covered at trial, including (i) awarding the Company an aggregate $9 million relating to the cost of NOx allowances charged by OMU to KU and the price of back-up power purchased by OMU from KU, plus pre- and post-judgment interest, and (ii) denying the Company's claim for damages based upon sub-par operations and availability of the OMU units. In April 2009, the court issued a ruling on various post-trial motions denying certain challenges to calculation elements of the $9 million award or of interest amounts associated therewith. In May 2009, KU and OMU executed a settlement agreement resolving the matter on a basis consistent with the court's prior rulings and the Company has received the agreed settlement amounts.

Sale and Leaseback Transaction. The Company is a participant in a sale and leaseback transaction involving its 62% interest in two jointly owned CTs at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, KU and LG&E entered into a tax-efficient, 18-year lease of the CTs. KU and LG&E have provided funds to fully defease the lease, and have executed an irrevocable notice to exercise an early purchase option contained in the lease after 15.5 years. The financial statement treatment of this transaction is no different than if KU had retained its ownership. The leasing transaction was entered into following receipt of required state and federal regulatory approvals.

In case of default under the lease, the Company is obligated to pay to the lessor its share of certain fees or amounts. Primary events of default include loss or destruction of the CTs, failure to insure or maintain the CTs and unwinding of the transaction due to governmental actions. No events of default currently exist with respect to the lease. Upon any termination of the lease, whether by default or expiration of its term, title to the CTs reverts jointly to KU and LG&E.

At December 31, 2009, the maximum aggregate amount of default fees or amounts was $8 million, of which KU would be responsible for 62% (approximately $5 million). The Company has made arrangements with E.ON U.S., via guarantee and regulatory commitment, for E.ON U.S. to pay its full portion of any default fees or amounts.

Letter of Credit. KU has provided letters of credit totaling $198 million supporting bonds of $195 million and a letter of credit totaling less than $1 million to support certain obligations related to workers' compensation.

Power Purchases. The Company has power purchase arrangements with OMU and OVEC. Under the OMU agreement, which will be terminated by OMU in May 2010, KU purchases all of the output of an approximately 400-Mw coal-fired generating station not required by OMU. The amount of power purchases available to the Company during 2010, which is expected to be approximately 5% of KU's total Kwh native load energy requirements, is dependent upon a number of factors including the OMU units' availability, maintenance schedules, fuel costs and OMU requirements. Payments are based on the total costs of the station allocated per terms of the OMU agreement. Included in the total costs is KU's proportionate share of debt service requirements on
$207 million of OMU bonds outstanding at December 31, 2009. The debt service is allocated to KU based on its annual allocated share of capacity, which averaged approximately 44% in 2009. KU does not guarantee the OMU bonds, or any requirements therein, in the event of default by OMU.

KU has a contract for power purchases with OVEC, terminating in 2026, for various Mw capacities. KU has an investment of 2.5% ownership in OVEC's common stock, which is accounted for on the cost method of accounting. The Company's share of OVEC's output is 2.5%, approximately 55 Mw of generation capacity. Future obligations for power purchases are shown in the following table:

	(In millions)
2010	$ 16
2011	10
2012	10
2013	11
2014	12
Thereafter	177
Total	$236

Coal and Gas Purchase Obligations. KU has contracts to purchase coal and natural gas transportation. Future obligations are shown in the following table:

	(In millions)
2010	$ 391
2011	307
2012	145
2013	88
2014	92
Thereafter	—(a)
Total	$1,023

(a) Obligations after 2014 are indexed to future market prices and are not included above since prices will be set in the future using the contracted methodology.

Construction Program. KU had $62 million of commitments in connection with its construction program at December 31, 2009.

In June 2006, KU and LG&E entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights. In March 2009, the parties completed an agreement resolving certain construction cost increases due to higher labor and per diem costs above an established baseline, and certain safety and compliance costs resulting from a change in law. The Company's share of additional costs from inception of the contract through the expected project completion in 2010 is estimated to be approximately $30 million. During the past and to date in 2010, KU and LG&E have received a number of contractual notices from the TC2 construction contractor asserting force majeure/excusable event claims for adjustments to either or both of contract price or construction schedule with respect to certain events which, if granted, may affect such contractual terms in addition to a possible extension of the commercial operations date, liquidated damages or other relevant provisions. The parties are continuing to discuss such matters in good faith and to resolve them in a commercially reasonable manner. The Company cannot currently estimate the ultimate outcome of these matters, including the extent, if any, that it results in increased costs charged for construction of TC2 and/or relief relating to the construction completion or operations dates.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the Kentucky Division for Air Quality ("KDAQ") in November 2005. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims, but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order, although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the two EPA objections. In March 2010, the Sierra Club submitted a petition to the EPA to object to the permit revision, which petition is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the right to challenge the final permit expires, the Company cannot predict the final outcome of this matter.

Thermostat Replacement. During January 2010, KU and LG&E announced a voluntary plan to replace certain thermostats which had been provided to customers as part of the Companies' demand reduction programs, due to concerns that the thermostats may present a safety hazard. Under the plan, the Companies anticipate replacing up to approximately 14,000 thermostats. Estimated costs associated with the replacement program may be $2 million. However, the Companies cannot fully predict the ultimate outcome of the replacement program or other effects or developments which may be associated with the thermostat replacement matter at this time.

Reserve Sharing Developments. The membership of KU and LG&E in the Midwest Contingency Reserve Sharing Group terminated on December 31, 2009. In December 2009, the Companies entered into arrangements with Tennessee Valley Authority and East Kentucky Power Cooperative to form a new reserve sharing group, the TEE Contingency Reserve Sharing Group. Contingency reserves, including spinning reserves and supplemental reserves, relate to power or capacity requirements that the Companies must have available for certain reliability purposes. In general, the operational and financial impact of reserve sharing arrangements varies based upon factors such as the terms of the agreement, the relative generating and operations conduct of the parties and relevant market prices. While the Companies do not anticipate the revised reserve sharing developments will have a material adverse effect on their prospective operations or financial condition, such outcome cannot be guaranteed.

Mine Safety Compliance Costs. In March 2006, the Mine Safety and Health Administration enacted Emergency Temporary Standards regulations and has issued additional regulations as the result of the passage of the Mine Improvement and New Emergency Response Act of 2006, which was signed into law in June 2006. At the state level, Kentucky and other states that supply coal to KU, have passed new mine safety legislation. These pieces of legislation require all underground coal mines to implement new safety measures and install new safety equipment. Under the terms of the majority of the long-term coal contracts the Company has in place, provisions are made to allow for price adjustments for compliance costs resulting from new or amended laws or regulations. KU's coal suppliers regularly submit price adjustments related to these compliance costs. The Company employs an external consultant to review all relevant mine safety compliance cost claims for validity and reasonableness. Depending upon the terms of the contracts and commercial practice, the Company may delay payment of the adjustments or pay certain adjustments subject to refund. At appropriate times in the review, payment or refund processes, KU may make adjustments to the values or amounts or values of inventory, accounts receivable or accounts payable relating to coal matters. In general, the Company expects to recover these coal-related cost adjustments through the FAC.

Environmental Matters. The Company's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to KU's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as National Ambient Air Quality Standards ("NAAQS"). Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, KU's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In January 2010, EPA issued a proposed rule to reconsider the NAAQS for Ozone, previously revised in 2008. The proposal would institute more stringent standards. At present, the Company is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

In July 2008, a federal appeals court issued a ruling finding deficiencies in the CAIR and vacating it. In December 2008, the Court amended its previous Order, directing the EPA to promulgate a new regulation, but leaving the CAIR in place in the interim. Depending upon the course of such matters, the CAIR could be superseded by new or revised NOx or SO_2regulations with different or more stringent requirements and SIPs which incorporate

CAIR requirements could be subject to revision. KU is also reviewing aspects of its compliance plan relating to the CAIR, including scheduled or contracted pollution control construction programs. Finally, as discussed below, the remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Companies' compliance plans relating thereto, due to the interconnection of the CAIR with such associated programs. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CAIR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Hazardous Air Pollutants. As provided in the Clean Air Act, as amended, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the Clean Air Mercury Rule ("CAMR") establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has announced that it intends to promulgate a new rule to replace the CAMR. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new mercury reduction rules with different or more stringent requirements. Kentucky has also repealed its corresponding state mercury regulations. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CAMR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Acid Rain Program. The Clean Air Act, as amended, imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern
U.S. The Clean Air Act, as amended, also contains requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its Clean Air Visibility Rule ("CAVR") detailing how the Clean Air Act's Best Available Retrofit Technology ("BART") requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the remand of CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit
1. KU's strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emission allowances and fuel switching to defer certain additional capital expenditures. In order to achieve the NOx emission reductions and associated obligations, KU installed additional NOx controls, including SCR technology, during the 2000 through 2009 time period at a cost of $221 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the environmental surcharge mechanism. Such monthly recovery is subject to periodic review by
the Kentucky Commission.

In order to achieve mandated emissions reductions, KU expects to incur additional capital expenditures totaling approximately $320 million during the 2010 through 2012 time period for pollution controls including FGD and SCR equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by the Company for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

GHG Developments. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. As discussed below, legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are on-going. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. At Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations are scheduled to meet in Cancun, Mexico in late 2010 to continue negotiations toward a binding agreement.

GHG Legislation. KU is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, (H.R. 2454), which is a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. If enacted into law, the bill would provide for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020, and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would initially be allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would also establish a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contains additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act (S. 1733), which is largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raises the emissions reduction target for 2020 to 20% below 2005 levels and does not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision has incorporated allowance allocation provisions similar to the House bill. The Company is closely monitoring the progress of the legislation, although the prospect for passage of comprehensive GHG legislation in 2010 is uncertain.

GHG Regulations. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities will be required to submit annual reports commencing with calendar year 2010. Also in September 2009, the EPA proposed to require new or modified sources with GHG emissions equivalent to at least 10,000 to 25,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration

Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the proposed rule. A final rule is expected in 2010.

The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. As a company with significant coal-fired generating assets, KU could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on its operations, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs. While the Company believes that many costs of complying with mandatory GHG reduction requirements or purchasing emission allowances to meet applicable requirements would likely be recoverable, in whole or in part under the ECR, where such costs are related to the Company's coal-fired generating assets, or other potential cost-recovery mechanisms, this cannot be assured.

GHG Litigation. A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. However, in March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing. The Comer complaint alleges that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the parent of KU and LG&E was included as a defendant in the complaint, but has not been subject to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. KU and LG&E are currently unable to predict further developments in the Comer case. KU and LG&E continue to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to their operations.

Brown New Source Review Litigation. In April 2006, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's new source review rules relating to work performed in 1997, on a boiler and turbine at KU's E.W. Brown generating station. In December 2006, the EPA issued a second NOV alleging the Company had exceeded heat input values in violation of the air permit for the unit. In March 2007, the Department of Justice filed a complaint in federal court in Kentucky alleging the same violations specified in the prior NOVs. The complaint sought civil penalties, including potential per-day fines, remedial measures and injunctive relief. In December 2008, the Company reached a tentative settlement with the government resolving all outstanding claims. The proposed consent decree, which was approved by the court in March 2009, provides for payment of a $1 million civil penalty; funding of $3 million in environmental mitigation projects; surrender of 53,000 excess SO_2 allowances; surrender of excess NOx allowances estimated at 650 allowances annually for eight years; installation of an FGD by December 31, 2010; installation of an SCR by December 31, 2012; and compliance with specified emission limits and operational restrictions.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and TC1 generating units and KU's Ghent 2 generating unit. KU and LG&E have complied with the information requests and are not able to predict further proceedings in this matter at this time.

Ghent Opacity NOV. In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. The Company is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

Ghent New Source Review NOV. In March 2009, the EPA issued an NOV alleging that KU violated certain provisions of the Clean Air Act's rules governing new source review and prevention of significant deterioration by installing FGD and SCR controls at its Ghent generating station without assessing potential increased sulfuric acid mist emissions. KU contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued a Section 114 information request seeking additional information on this matter. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial position or results of operations.

Ash Ponds, Coal-Combustion Byproducts and Water Discharges. The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the Tennessee Valley Authority's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including KU, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of the Company's impoundments, which the EPA found to be in satisfactory condition. The Company is awaiting final inspection reports for additional impoundments. The EPA and other agencies are currently considering the need to revise applicable standards governing the structural integrity of ash ponds and other impoundments. In addition, the EPA has announced that it is re-evaluating current regulatory requirements applicable to coal combustion byproducts and anticipates pro- posing new rules by early 2010. The EPA is considering a wide range of regulatory options including subjecting ash ponds and landfills handling coal combustion byproducts to regulation under the hazardous waste program. Finally, the EPA has announced plans to develop revised effluent limitations guidelines and standards governing discharges from power plants. The Company is monitoring these ongoing regulatory developments, but will be unable to determine the impact until such time as new rules are finalized.

General Environmental Proceedings. From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable envi- ronmental laws and regulations. Such matters include a completed settlement with state regulators regarding particulate limits in the air permit for KU's Tyrone generating station, remediation activities for, or other risks relating to elevated Polychlorinated Biphenyl ("PCB") levels at existing properties, and liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 10 — Jointly Owned Electric Utility Plant

KU and LG&E are nearing completion of TC2, a jointly owned unit at the Trimble County site. KU and LG&E own undivided 60.75% and 14.25% interests, respectively, in TC2. Of the remaining 25% of TC2, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction, and fuel, operation and maintenance cost when TC2 begins operation, which is scheduled to occur in 2010. In December 2009 and June 2008, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million and $10 million, respectively.

The following data represent shares of the jointly owned property (capacity based on nameplate rating):

	TC2				
	LG&E	**KU**	**IMPA**	**IMEA**	**Total**
Ownership interest	14.25%	60.75%	12.88%	12.12%	100%
Mw capacity	119	509	108	102	838

	(In millions)
KU's 60.75% ownership:	
Plant held for future use	$121
Construction work in progress	679
Accumulated depreciation	63
Net book value	$737
LG&E's 14.25% ownership:	
Plant held for future use	$ 5
Construction work in progress	169
Accumulated depreciation	2
Net book value	$172

KU and LG&E jointly own the following CTs and related equipment (capacity based on net summer capability):

	KU				LG&E				Total			
Ownership Percentage	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value
					($ in millions)							
KU 47%, LG&E 53%(a)	129	54	(13)	41	146	59	(15)	44	275	113	(28)	85
KU 62%, LG&E 38%(b)	190	79	(15)	64	118	46	(7)	39	308	125	(22)	103
KU 71%, LG&E 29%(c)	228	82	(21)	61	92	33	(8)	25	320	115	(29)	86
KU 63%, LG&E 37%(d)	404	140	(25)	115	236	82	(16)	66	640	222	(41)	181
KU 71%, LG&E 29%(e)	n/a	9	(2)	7	n/a	3	(1)	2	n/a	12	(3)	9

(a) Comprised of Paddy's Run 13 and E.W. Brown 5. In addition to the above jointly owned utility plant, there is an inlet air cooling system attributable to unit 5 and units 8-11 at the E.W. Brown facility. This inlet air cooling system is not jointly owned, however, it is used to increase production on the units to which it relates, resulting in an additional 88 Mw of capacity for KU.

(b) Comprised of units 6 and 7 at the E.W. Brown facility.

(c) Comprised of units 5 and 6 at the Trimble County facility.

(d) Comprised of CT Substation 7-10 and units 7, 8, 9 and 10 at the Trimble County facility.

(e) Comprised of CT Substation 5 and 6 and CT Pipeline at the Trimble County facility.

Both KU's and LG&E's participating share of direct expenses of the jointly owned plants is included in the corresponding operating expenses on each company's respective income statement (e.g., fuel, maintenance of plant, other operating expense).

Note 11 — Related Party Transactions

KU, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. These transactions are generally performed at cost and are in accordance with the FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

KU and LG&E purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as operating revenues and purchased power operating expense. KU intercompany electric revenues and purchased power expense for the years ended December 31, were as follows:

	2009	2008	2007
	(In millions)		
Electric operating revenues from LG&E	$ 21	$ 80	$46
Power purchased from LG&E	101	109	93

Interest Charges

See Note 8, Notes Payable and Other Short-Term Obligations, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's intercompany interest income and expense for the years ended December 31, were as follows:

	2009	2008	2007
	(In millions)		
Interest on money pool loans	$—	$ 2	$ 6
Interest on Fidelia loans	69	56	35

Other Intercompany Billings

E.ON U.S. Services provides KU with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. Services on behalf of KU, labor and burdens of E.ON U.S. Services employees performing services for KU, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of KU. The cost of these services is directly charged to KU, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, KU and LG&E provide services to each other and to E.ON U.S. Services. Billings between KU and LG&E relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to E.ON U.S. Services include cash received by E.ON U.S. Services on behalf of KU, primarily tax settlements, and other payments made by KU on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from KU for the years ended December 31, were as follows:

	2009	2008	2007
	(In millions)		
E.ON U.S. Services billings to KU	$169	$227	$488
LG&E billings to KU	44	5	12
KU billings to E.ON U.S. Services	14	3	26
KU billings to LG&E	78	75	6

In December 2009 and June 2008, LG&E sold assets to KU related to the construction of TC2, including $3 million of unamortized investment tax credits, with net book values of $48 million and $10 million, respectively.

In March and June 2009, the Company received capital contributions of $50 million and $25 million, respectively, from its common shareholder, E.ON U.S.

In 2008 and 2007, KU received capital contributions from its common shareholder, E.ON U.S., totaling $145 million and $75 million, respectively.

Note 12 — Subsequent Events

Subsequent events have been evaluated through March 19, 2010, the date of issuance of these statements and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

On March 4, 2010, the Virginia Commission approved the stipulation related to the rate increase filing with rates to become effective in April 2010.

On January 29, 2010, KU filed an application with the Kentucky Commission requesting an increase in base electric rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. KU has requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates have been suspended until August 1, 2010, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding.

On January 13, 2010, the Company made a $13 million contribution to its pension plan.

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Report of Independent Auditors

To the Shareholder of Kentucky Utilities Company:

In our opinion, the accompanying balance sheets and the related statements of capitalization, income, retained earnings, and cash flows present fairly, in all material respects, the financial position of Kentucky Utilities Company at December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assertion of the effectiveness of internal control over financial reporting, included in "Controls and Procedures" appearing on page 23 of the 2009 Kentucky Utilities Company financial statements and additional information. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits of the financial statements in accordance with auditing standards generally accepted in the United States of America and our audit of internal control over financial reporting in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and those charged with governance; and (iii) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

PricewaterhouseCoopers LLP

Louisville, Kentucky
March 19, 2010

Kentucky Utilities Company

Condensed Financial Statements
(Unaudited)

As of September 30, 2010 and December 31, 2009
and for the three and nine months ended
September 30, 2010 and 2009

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Companies	KU and LG&E
Company	KU
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Edison Electric Institute
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
GHG	Greenhouse Gas
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
KDAQ	Kentucky Division for Air Quality
Kentucky Commission	Kentucky Public Service Commission
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PPL	PPL Corporation
S&P	Standard & Poor's Ratings Services
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
Servco	LG&E and KU Services Company (formerly E.ON U.S. Services Inc.)
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
Virginia Commission	Virginia State Corporation Commission

Kentucky Utilities Company

Condensed Financial Statements
(Unaudited)

As of September 30, 2010 and December 31, 2009 and for the three and nine months ended September 30, 2010 and 2009

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Kentucky Utilities Company

Condensed Statements of Income

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(Unaudited) (Millions of $)			
Operating revenues (Note 10)	$416	$341	$1,146	$1,009
Operating expenses:				
Fuel for electric generation	146	114	391	329
Power purchased (Note 10)	41	47	135	154
Other operation and maintenance expenses	86	22	251	230
Depreciation, accretion and amortization	38	33	106	99
Total operating expenses	311	216	883	812
Operating income	105	125	263	197
Interest expense (Note 8)	2	2	5	5
Interest expense to affiliated companies (Notes 8 and 10)	18	18	55	51
Other income (expense) — net	1	—	2	7
Income before income taxes	86	105	205	148
Income tax expense (Note 7)	32	39	76	49
Net income	$ 54	$ 66	$ 129	$ 99

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

Kentucky Utilities Company

Condensed Statements of Comprehensive Income

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(Unaudited) (Millions of $)			
Net income	$54	$66	$129	$99
Comprehensive income (loss) attributable to unconsolidated venture — net of tax benefit of $1, $0, $1 and $0, respectively	(2)	—	(2)	—
Comprehensive income	$52	$66	$127	$99

Condensed Statements of Retained Earnings

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(Unaudited) (Millions of $)			
Balance at beginning of period	$1,403	$1,228	$1,328	$1,195
Net income	54	66	129	99
	1,457	1,294	1,457	1,294
Cash dividends declared (Note 10)	(50)	—	(50)	—
Balance at end of period	$1,407	$1,294	$1,407	$1,294

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

Kentucky Utilities Company

Condensed Balance Sheets

	September 30, 2010	December 31, 2009
	(Unaudited) (Millions of $)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2	$ 2
Accounts receivable — net:		
Customer — less reserves of $2 in 2010 and $1 in 2009	172	155
Affiliated companies	—	9
Other — less reserves of $2 in 2010 and 2009	28	18
Materials and supplies:		
Fuel (predominantly coal)	98	98
Other materials and supplies	42	39
Regulatory assets (Note 2)	14	32
Prepayments and other current assets	11	13
Total current assets	367	366
Investment in unconsolidated venture	12	12
Property, plant and equipment:	5,426	4,892
Regulated utility plant — electric		
Accumulated depreciation	(1,902)	(1,838)
Net regulated utility plant	3,524	3,054
Construction work in progress	946	1,257
Property, plant and equipment — net	4,470	4,311
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension benefits	105	105
Other regulatory assets	110	117
Cash surrender value of key man life insurance	39	38
Other assets	7	7
Total deferred debits and other assets	261	267
Total assets	$ 5,110	$ 4,956

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

Kentucky Utilities Company

Condensed Balance Sheets (continued)

	September 30, 2010	December 31, 2009
	(Unaudited) (Millions of $)	
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt (Notes 5 and 8)	$ 228	$ 228
Current portion of long-term debt to affiliated company (Note 5)	33	33
Notes payable to affiliated companies (Notes 8 and 10)	61	45
Accounts payable	105	107
Accounts payable to affiliated companies (Note 10)	71	88
Customer deposits	23	22
Regulatory liabilities (Note 2)	12	4
Other current liabilities	39	42
Total current liabilities	572	569
Long-term debt:		
Long-term debt (Notes 5 and 8)	123	123
Long-term debt to affiliated company (Notes 5, 8 and 10)	1,298	1,298
Total long-term debt	1,421	1,421
Deferred credits and other liabilities:		
Deferred income taxes	378	336
Accumulated provision for pensions and related benefits (Note 6)	160	160
Investment tax credits (Note 7)	104	104
Asset retirement obligations (Note 3)	59	34
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	343	331
Other regulatory liabilities	24	29
Other liabilities	20	20
Total deferred credits and other liabilities	1,088	1,014
Common equity:		
Common stock, without par value — Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital	316	316
Accumulated other comprehensive loss	(2)	—
Retained earnings:		
Retained earnings	1,397	1,318
Undistributed earnings from unconsolidated venture	10	10
Total common equity	2,029	1,952
Total liabilities and equity	$5,110	$4,956

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

Kentucky Utilities Company

Condensed Statements of Cash Flows

	For the Nine Months Ended September 30, 2010	2009
	(Unaudited) (Millions of $)	
Cash flows from operating activities:		
Net income	$ 129	$ 99
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, accretion and amortization	106	99
Deferred income taxes — net	42	48
Investment tax credits (Note 7)	—	17
Provision for pension and postretirement benefits	11	13
Undistributed earnings of unconsolidated venture	(4)	10
Other	1	3
Changes in current assets and liabilities:		
Accounts receivable	(6)	30
Materials and supplies	(3)	(21)
Regulatory assets and liabilities	26	(1)
Accounts payable	(20)	(4)
Accounts payable to affiliated companies	31	(8)
Other current assets and liabilities	—	(10)
Pension and postretirement funding (Note 6)	(17)	(17)
Other regulatory assets and liabilities	(3)	(64)
Other — net	7	(4)
Net cash provided by operating activities	300	190
Cash flows from investing activities:		
Construction expenditures	(218)	(378)
Purchases of assets from affiliate	(48)	—
Change in restricted cash	—	9
Net cash used in investing activities	(266)	(369)
Cash flows from financing activities:		
Borrowings from affiliated company (Note 8)	104	106
Repayments on borrowings from affiliated company (Note 8)	(88)	—
Payment of dividends (Note 10)	(50)	—
Capital contribution (Note 10)	—	75
Net cash (used in) provided by financing activities	(34)	181
Change in cash and cash equivalents	—	2
Cash and cash equivalents at beginning of period	2	2
Cash and cash equivalents at end of period	$ 2	$ 4

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

Kentucky Utilities Company

Notes to Condensed Financial Statements
(Unaudited)

Note 1 — General

KU's common stock is wholly-owned by E.ON U.S., an indirect wholly-owned subsidiary of E.ON. In the opinion of management, the unaudited condensed financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for fair statements of income, comprehensive income, and retained earnings, balance sheets, and statements of cash flows for the periods indicated. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted. These unaudited condensed financial statements and notes should be read in conjunction with the Company's Financial Statements and Additional Information ("Annual Report") for the year ended December 31, 2009, including the audited financial statements and notes therein.

The December 31, 2009, condensed balance sheet included herein is derived from the December 31, 2009, audited balance sheet. Amounts reported in the condensed statements of income are not necessarily indicative of amounts expected for the respective annual periods due to the effects of seasonal temperature variations on energy consumption, regulatory rulings, the timing of maintenance on electric generating units, changes in mark-to-market valuations, changing commodity prices and other factors.

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2010 presentation with no impact on total assets, liabilities and capitalization or previously reported net income and net cash flows.

<u>PPL Acquisition</u>

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments, PPL and E.ON.

The Agreement provides for the sale of E.ON U.S. to PPL. Pursuant to the Agreement, at closing, PPL will acquire all of the outstanding limited liability company interests of E.ON U.S. for cash consideration of $2.6 billion. In addition, pursuant to the Agreement, PPL agreed to assume $764 million of pollution control bonds and medium term notes and to repay indebtedness owed by E.ON U.S. and its subsidiaries to E.ON US Investments and its affiliates. Such affiliate indebtedness is currently estimated to be $4.2 billion. The aggregate consideration payable by PPL on closing is currently estimated to be $7.6 billion (including the assumed indebtedness), subject to contractually agreed adjustments.

The transaction is subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including state regulators in Kentucky, Virginia and Tennessee, and the FERC) and the absence of injunctions or restraints imposed by governmental entities. As of October 26, 2010, all of the required regulatory approvals were received, and the transaction is expected to close on November 1, 2010.

Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings, and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010, at which time a unanimous settlement agreement was presented. In the settlement, KU and LG&E commit that no base rate increases would take effect before January 1, 2013. The KU and LG&E rate increases that took effect on August 1, 2010, were not impacted by the settlement. Under the terms of the settlement, the Companies retain the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be
permissible during that period for existing fuel, environmental and demand-side management cost trackers. The

agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Com- panies file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits the Companies to earn up to a 10.75 percent return on equity. Any earnings above a 10.75 percent return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of KU and LG&E via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions' Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, KU and LG&E and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which has subsequently been filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that the Company has agreed to not seek the same transaction-related cost from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010.

On September 30, 2010, October 19, 2010 and October 21, 2010, respectively, KU received Kentucky Commission, Virginia Commission and Tennessee Regulatory Authority approvals to complete certain refinancing transactions in connection with the anticipated PPL acquisition and other business factors. Based on credit and financial market conditions, KU anticipates issuing up to $1.5 billion in first mortgage bonds, the proceeds of which will substantially be used to refund existing long-term intercompany debt. On October 29, 2010, as required by existing covenants, in connection with the anticipated issuance of any such secured debt, KU completed collateralization of certain outstanding pollution control bond debt series which were formerly unsecured. Pursuant to such collateralization, approximately $351 million in existing pollution control debt became collateralized debt, supported by a first mortgage lien. KU also anticipates replacing its $35 million bilateral line of credit with an unaffiliated institution by entering into a multi-year revolving credit facility with several financial institutions in an aggregate amount not to exceed $400 million. KU may complete these transactions, in whole or in part, during late 2010 and early 2011. See Note 8, Short-Term and Long-Term Debt, for further information regarding the refinancing, remarketing or conversion of existing pollution control debt.

Recent Accounting Pronouncements

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances, and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 — Rates and Regulatory Matters

KU's Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and notes payable) including certain regulatory adjustments to exclude non-regulated investments and environ- mental compliance plans recovered separately through the ECR mechanism. Currently, none of the regulatory assets or regulatory liabilities are excluded from the return on capitalization utilized in the calculation of Kentucky base rates; therefore, a return is earned on all Kentucky regulatory assets.

KU's Virginia base rates are calculated based on a return on rate base (net utility plant less deferred taxes and miscellaneous deductions). All regulatory assets and liabilities are excluded from the return on rate base utilized in the calculation of Virginia base rates.

For a description of each line item of regulatory assets and liabilities and for descriptions of certain matters which may not have undergone material changes relating to the period covered by this quarterly report, reference is made to Note 2, Rates and Regulatory Matters, of KU's Annual Report for the year ended December 31, 2009.

2010 Kentucky Rate Case

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. KU requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates were suspended until August 1, 2010. A number of intervenors entered the rate case, including the AG, certain representatives of industrial and low-income groups and other third parties, and submitted filings challenging the Company's requested rate increases, in whole or in part. A hearing was held on June 8, 2010. KU and all of the intervenors, except the AG, agreed to a stipulation providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation. The new rates became effective on August 1, 2010.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. A public hearing was held during January 2010. As permitted, pursuant to a Virginia Commission Order, KU elected to implement the proposed rates effective November 1, 2009, on an interim basis. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded approximately $1 million in interim rate amounts in excess of the ultimate approved rates. During August 2010, a report was filed detailing the costs of the refunds, the accounts charged and details validating that all refunds have been applied.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rate to an unbundled formula rate, including an annual adjustment mechanism. In May 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustment to the formula rate. This updated rate became effective on July 1, 2010, subject to certain review procedures by the wholesale requirements customers and the FERC, including potential refunds in the case of disallowed costs or charges.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. In August 2009, the FERC accepted the issue for briefing and the parties completed briefing submissions during 2009. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in KU's balance sheets as of:

	September 30, 2010	December 31, 2009
	(In millions)	
Current regulatory assets:		
Storm restoration(a)	$ 6	$ —
FAC(b)	4	1
ECR(b)	—	28
MISO exit(a)	1	2
Other(c)	3	1
Total current regulatory assets	$ 14	$ 32
Non-current regulatory assets:		
Pension benefits(d)	$105	$105
Other non-current regulatory assets:		
Storm restoration(a)	52	59
ARO(e)	34	30
Unamortized loss on bonds(a)	12	12
MISO exit(a)	4	9
Other(c)	8	7
Subtotal other non-current regulatory assets	110	117
Total non-current regulatory assets	$215	$222
Current regulatory liabilities:		
ECR	$ 6	$ —
DSM	4	3
Other(f)	2	1
Total current regulatory liabilities	$ 12	$ 4
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$343	$331
Other non-current regulatory liabilities:		
Deferred income taxes — net	8	9
Postretirement benefits	9	9
MISO exit	1	4
Other(f)	6	7
Subtotal other non-current regulatory liabilities	24	29
Total non-current regulatory liabilities	$367	$360

(a) These regulatory assets are recovered through base rates.

(b) The FAC and ECR regulatory assets have separate recovery mechanisms with recovery within twelve months.

(c) Other regulatory assets:

- Other current and non-current regulatory assets, including the CMRG and KCCS contributions, an EKPC FERC transmission settlement agreement and rate case expenses, are recovered through base rates.
- The current portion of the unamortized loss on bonds is recovered through base rates.

- KU generally recovers the FERC jurisdictional portion of the EKPC FERC transmission settlement agreement included in current and non-current regulatory assets in the application of the annual Open Access Transmission Tariff formula rate updates.
- Recovery of the FERC jurisdictional pension expense in non-current regulatory assets will be requested in a future FERC rate case.

(d) KU generally recovers this asset through pension expense included in the calculation of base rates.

(e) When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability.

(f) Other current and non-current regulatory liabilities includes the Virginia levelized fuel factor regulatory liability, ARO liabilities and a change in accounting method for FERC jurisdictional spare parts. ARO liabilities are established from the removal costs accrued through depreciation under regulatory accounting for assets associated with AROs.

Storm Restoration

In January 2009, a significant ice storm passed through KU's service territory causing approximately 199,000 customer outages and was followed closely by a severe wind storm in February 2009, which caused approximately 44,000 customer outages. KU incurred $57 million in incremental operation and maintenance expenses and $33 million in capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, the Company established a regulatory asset of $57 million for actual costs incurred. The Company received approval in its 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service territory causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset and defer for future recovery approximately $3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $3 million based on its actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, the Company established a regulatory asset of $2 million for actual costs incurred. The Company received approval in its 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

FAC

In August 2010, the Kentucky Commission initiated a six-month review of KU's FAC mechanism for the expense period ended April 2010. An order is expected by the end of the year.

In February 2010, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor beginning with service rendered in April 2010. An Order was issued in April 2010, resulting in an agreed upon decrease of 23% from the fuel factor in effect for April 2009 through March 2010.

In January 2010, the Kentucky Commission initiated a six-month review of KU's FAC mechanism for the expense period ended August 2009. In May 2010, an Order was issued approving the charges and credits billed through the FAC during the review period.

ECR

In July 2010, the Kentucky Commission initiated a six-month review of KU's environmental surcharge for the billing period ending April 2010. An order is expected in the fourth quarter of 2010.

In January 2010, the Kentucky Commission initiated a six-month review of KU's environmental surcharge for the billing period ending October 2009. In May 2010, an Order was issued approving the amounts billed through the ECR during the six-month period and the rate of return on capital and allowing recovery of the under-recovery position in subsequent monthly filings.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, KU reached a unanimous settlement with all parties to the case, and the Kentucky Commission issued an Order approving KU's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle. At December 31, 2009, the Company had a regulatory asset of $28 million, which changed to a regulatory liability in the first quarter of 2010, as a result of these roll-in adjustments to base rates. At September 30, 2010, the regulatory liability balance was $6 million.

MISO

In August 2010, the FERC issued three Orders accepting most facets of several MISO Revenue Sufficiency Guarantee ("RSG") compliance filings. The FERC ordered the MISO to issue refunds for RSG charges that were imposed by the MISO on the assumption that there were rate mismatches for the period beginning November 5, 2007 through the present. There is no financial statement impact to the Company from this Order, as the MISO had anticipated that the FERC would require these refunds and had preemptively included them in the resettlements paid in 2009. The FERC denied MISO's proposal to exempt certain resources from RSG charges, effective prospectively. The FERC accepted portions and rejected portions of the MISO's proposed RSG rate Redesign Proposal, which will be effective when the software is ready for implementation subject to further compliance filings. The impact of the Redesign Proposal on the Company cannot be estimated at this time.

Other Regulatory Matters

TC2 Depreciation

In August 2009, the Companies jointly filed an application with the Kentucky Commission to approve new common depreciation rates for applicable jointly-owned TC2-related generating, pollution control and other plant equipment and assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010, and authorized the Companies on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 Transmission Matters

KU's and LG&E's CCN for a transmission line associated with the TC2 construction has been challenged by certain property owners in Hardin County, Kentucky. In August 2006, the Companies obtained a successful dismissal of the challenge at the Franklin County Circuit Court, which was reversed by the Kentucky Court of Appeals in December 2007. In April 2009, the Kentucky Supreme Court granted KU's and LG&E's motion for discretionary review of the Court of Appeals' decision. In August 2010, the Kentucky Supreme Court issued an Order reversing the decision of the Kentucky Court of Appeals and reinstating the Franklin County Circuit Court's dismissal of the property owners' challenge to KU's and LG&E's CCN.

During 2008, KU obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals. In May 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties. In May 2010, the landowners filed a petition for reconsideration with the Court of Appeals. In July 2010, the Court of Appeals denied that petition. In August, 2010, the landowners filed for discretionary review of that denial by the Kentucky Supreme Court.

In a separate proceeding, certain Hardin County landowners filed an action in federal district court in Louisville, Kentucky against the U.S. Army challenging the same transmission line claiming that certain

Fort Knox-related sections of the line failed to comply with certain National Historic Preservation Act procedural requirements. In October 2009, the federal court granted the defendants' motion for summary judgment and dismissed the plaintiffs' claims. During November 2009, the petitioners filed submissions for review of the decision with the 6th Circuit Court of Appeals. In May 2010, the appellate court issued an order approving the plaintiffs' voluntary withdrawal of their appeals.

Consistent with the regulatory authorizations and relevant legal proceedings, the Companies have completed construction activities on temporary or permanent transmission line segments. During the second quarter of 2010, the Companies placed into operation an appropriate combination of permanent and temporary sections of the transmission line. While the Companies are not currently able to predict the ultimate outcome and possible financial effects of the remaining legal proceedings, the Companies do not believe the matter involves relevant or continuing risks to operations.

Mandatory Reliability Standards

As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various Regional Reliability Organizations ("RROs") by the North American Electric Reliability Corporation ("NERC"), which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending on the circumstances of the violation. The Companies are members of SERC, which acts as KU's and LG&E's RRO. During December 2009, SERC and the Companies agreed to settlements involving penalties totaling less than $1 million for each utility related to their self-reports during June and October 2008, concerning possible violations of standards. During December 2009 and April, July and August 2010, the Companies submitted ten self-reports relating to various standards, which self-reports remain in the early stages of RRO review, and therefore, the Companies are unable to estimate the outcome of these matters. Mandatory reliability standard settlements commonly also include non-penalty elements, including compliance steps and mitigation plans. Settlements with SERC proceed to NERC and FERC review before becoming final. While the Companies believe they are in compliance with the mandatory reliability standards, events of potential non- compliance may be identified from time-to-time. The Companies cannot predict such potential violations or the outcome of the self-reports described above.

Note 3 — Asset Retirement Obligation

A summary of KU's net ARO assets, ARO liabilities and regulatory assets established under the asset retirement and environmental obligations guidance of the FASB ASC follows:

	ARO Net Assets	ARO Liabilities	Regulatory Assets
		(In millions)	
As of December 31, 2009	$ 4	$(34)	$30
ARO accretion	—	(2)	2
ARO revaluation	21	(23)	2
As of September 30, 2010	$25	$(59)	$34

As of September 30, 2010, the Company performed a revaluation of its AROs as a result of recently proposed environmental legislation and improved ability to forecast asset retirement costs due to recent construction and retirement activity.

Pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC, an offsetting regulatory credit was recorded in depreciation and amortization in the income statement of $2 million for the nine months ended September 30, 2010 for the ARO accretion and depreciation expense. KU's AROs are primarily related to the final retirement of assets associated with generating units.

KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration on removal of the property. Therefore, under the asset retirement and environmental obligations guidance of the FASB ASC, no material asset retirement obligations are recorded for transmission and distribution assets.

Note 4 — Derivative Financial Instruments

KU is subject to interest rate and commodity price risk related to on-going business operations. It currently manages these risks using derivative instruments, including swaps and forward contracts. The Company's policies allow the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At September 30, 2010, a 100 basis point change in the benchmark rate on KU's variable rate debt, not effectively hedged by an interest rate swap, would impact pre-tax interest expense by $4 million annually. Although the Company's policies allow for the use of interest rate swaps, as of September 30, 2010 and December 31, 2009, KU had no interest rate swaps outstanding.

The Company does not net collateral against derivative instruments.

Energy Trading and Risk Management Activities

KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to manage price risk and are accounted for as non-hedging derivatives on a mark-to-market basis in accordance with the derivatives and hedging topic of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Inter- continental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs include prices quoted by brokers or observable inputs other than quoted prices, such as one-sided bids or offers as of the balance sheet date. Quotes are verified quarterly using an independent pricing source of actual transactions. Quotes for combined off- peak and weekend timeframes are allocated between the two timeframes based on their historical proportional ratios to the integrated cost. No other adjustments are made to the forward prices. No changes to valuation techniques for energy trading and risk management activities occurred during 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

KU's financial assets and liabilities as of September 30, 2010 and December 31, 2009, arising from energy trading and risk management contracts not designated as hedging instruments accounted for at fair value total less than $1 million and are recorded in prepayments and other current assets and other current liabilities, respectively.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, KU seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, KU assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At September 30, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company has reserves against counterparty credit risk based on the counterparty's credit rating and applying historical default rates within varying credit ratings over time provided by S&P or Moody's. At September 30, 2010 and December 31, 2009, counterparty credit reserves related to energy trading and risk management contracts were less than $1 million.

The net volume of electricity based financial derivatives outstanding at September 30, 2010 and December 31, 2009, was zero and 43,400 Mwhs, respectively. No cash collateral related to the energy trading and risk management contracts was required at September 30, 2010. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2009. Cash collateral related to the energy trading and risk management contracts is categorized as other accounts receivable in the accompanying balance sheets.

KU manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions, and therefore realized and unrealized gains and losses are included in the statements of income.

The following tables present the effect of derivatives not designated as hedging instruments on income:

Loss Recognized in Income	Location	Three Months Ended September 30, 2010(a)	Three Months Ended September 30, 2009
		(In millions)	
Unrealized loss	Electric revenues	$—	$(3)

Loss Recognized in Income	Location	Nine Months Ended September 30, 2010(a)	Nine Months Ended September 30, 2009
		(In millions)	
Unrealized loss	Electric revenues	$—	$(1)

(a) Unrealized loss was less than $1 million

Net realized gains were less than $1 million in the three and nine months ended September 30, 2010 and 2009, respectively.

Credit Risk Related Contingent Features

Certain of the Company's derivative instruments contain provisions that require the Company to provide immediate and on-going collateralization on derivative instruments in net liability positions based on the Company's credit ratings from each of the major credit rating agencies. At September 30, 2010, there are no energy trading and risk management contracts with credit risk related contingent features that are in a liability position and no collateral posted in the normal course of business. At September 30, 2010, a one notch downgrade of the Company's credit rating would have no effect on the energy trading and risk management contracts or collateral required.

Note 5 — Fair Value Measurements

KU adopted the fair value guidance in the FASB ASC in two phases. Effective January 1, 2008, the Company adopted it for all financial instruments and non-financial instruments accounted for at fair value on a recurring basis, and January 1, 2009, the Company adopted it for all non-financial instruments accounted for at fair value on a non- recurring basis. The FASB ASC guidance clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. As a basis for considering such assumptions, the FASB ASC guidance establishes a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value.

The carrying values and estimated fair values of KU's non-trading instruments:

	September 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Long-term bonds (including current portion of $228 million)	$ 351	$ 352	$ 351	$ 351
Long-term debt to affiliated company (including current portion of $33 million)	1,331	1,527	1,331	1,401

The long-term bond valuations reflect prices quoted by investment banks, which are active in the market for these debt instruments. The fair value of the long-term debt due to affiliated company is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates as determined based on quotes from investment banks that are actively involved in capital markets for utilities and factor in KU's credit ratings and default risk. The fair values of cash and cash equivalents, accounts receivable, cash surrender value of key man life insurance, accounts payable and notes payable are substantially the same as their carrying values.

KU has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures topic of the FASB ASC, as follows:

- Level 1 — Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets
- Level 2 — Include other inputs that are directly or indirectly observable in the marketplace
- Level 3 — Unobservable inputs which are supported by little or no market activity

The fair value hierarchy also requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

The Company classifies its derivative cash collateral balances within level 1 based on the funds being held in a demand deposit account. The Company classifies its derivative energy trading and risk management contracts within level 2 because it values them using prices actively quoted for proposed or executed transactions, quoted by brokers or observable inputs other than quoted prices.

KU's financial assets and liabilities as of September 30, 2010 and December 31, 2009, arising from energy trading and risk management contracts accounted for at fair value on a recurring basis total less than $1 million. No cash collateral related to the energy trading and risk management contracts was required at September 30, 2010. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2009.

There were no level 3 measurements for the periods ending September 30, 2010 and December 31, 2009.

Note 6 — Pension and Other Postretirement Benefit Plans

Net Periodic Benefit Costs

The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both KU employees and Servco employees who are providing services to KU. The Servco costs are allocated to KU based on employees' labor charges and are approximately 53% and 51% of Servco costs for September 30, 2010 and 2009, respectively.

	Pension Benefits Three Months Ended September 30,					
	2010			2009		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
	(In millions)					
Service cost	$ 2	$ 1	$ 3	$ 2	$ 1	$ 3
Interest cost	4	2	6	4	2	6
Expected return on plan assets	(5)	(2)	(7)	(3)	(1)	(4)
Amortization of prior service cost	—	1	1	—	—	—
Amortization of actuarial loss	2	1	3	2	1	3
Net periodic benefit cost	$ 3	$ 3	$ 6	$ 5	$ 3	$ 8

	Other Postretirement Benefits Three Months Ended September 30,					
	2010			2009		
	(In millions)					
	KU	Servco Allocation to KU(a)	Total KU	KU	Servco Allocation to KU(a)	Total KU
Interest cost	$2	$—	$2	$1	$—	$1
Net periodic benefit cost	$2	$—	$2	$1	$—	$1

(a) amounts are less than $1 million

	Pension Benefits Nine Months Ended September 30,					
	2010			2009		
	(In millions)					
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 5	$ 4	$ 9	$ 4	$ 4	$ 8
Interest cost	14	6	20	13	5	18
Expected return on plan assets	(13)	(5)	(18)	(10)	(4)	(14)
Amortization of prior service cost	—	1	1	1	1	2
Amortization of actuarial loss	5	2	7	6	2	8
Net periodic benefit cost	$ 11	$ 8	$ 19	$ 14	$ 8	$ 22

	Other Postretirement Benefits Nine Months Ended September 30,					
	2010			2009		
	(In millions)					
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	4	—	4	3	—	3
Expected return on plan assets	(1)	—	(1)	—	—	—
Amortization of transitional obligation	1	—	1	1	—	1
Net periodic benefit cost	$ 5	$ 1	$ 6	$ 5	$ 1	$ 6

Contributions

In January 2010, KU and Servco made discretionary pension plan contributions of $13 million and $9 million, respectively. The amount of future contributions to the pension plan will depend on the actual return on plan assets and other factors, but the Company’s intent is to fund the pension plan in a manner consistent with the requirements of the Pension Protection Act of 2006.

Through September 2010, KU made contributions to other postretirement benefit plans totaling $4 million. An additional contribution totaling $1 million was made in October. The Company anticipates further funding to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time, and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

During each of the three and nine months ended September 30, 2010, KU recorded an income tax expense of less than $1 million, to recognize the impact of the elimination of the tax deduction related to the Medicare Retiree Drug Subsidy that becomes effective in 2013.

Specific provisions within Health Care Reform that may impact KU include:

- Beginning in 2011, requirements extend dependent coverage up to age 26, remove the $2 million lifetime maximum and eliminate cost sharing for certain preventative care procedures.
- Beginning in 2018, a potential excise tax is expected on high-cost plans providing health coverage that exceeds certain thresholds.

KU continues to evaluate all implications of Health Care Reform on its benefit programs but at this time cannot predict the significance of those implications.

Note 7 — Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, E.ON US Investments Corp., for each tax period. Each subsidiary of the consolidated tax group, including KU, calculates its separate income tax for each period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. The Company also files income tax returns in various state jurisdictions. While 2007 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2006-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years beginning with 2007 were examined under an IRS pilot program named "Compliance Assurance Process" ("CAP"). This program accelerates the IRS' review to begin during the year applicable to the return and ends 90 days after the return is filed. For 2008, the IRS allowed additional deductions in connection with the Company's application for a change in repair deductions and disallowed some of the bonus depreciation claimed on the original return. The net temporary tax impact for the Company was $12 million and was recorded in the second quarter of 2010. Tax years 2009 and 2010 are also being examined under CAP. The 2009 federal return was filed in the third quarter, and the IRS issued a Partial Acceptance Letter with the 2009 return. The IRS is continuing to review bonus depreciation, storms and other repairs. No material impact is expected from the IRS review. For the tax year 2010, no material items have been raised by the IRS at this time.

Additions and reductions of uncertain tax positions during 2010 and 2009 were less than $1 million. Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million and are based on the expiration of the audit periods as defined in the statutes. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of September 30, 2010 and December 31, 2009. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. KU records the interest as interest expense and penalties as operating expenses in the income statement and accrued expenses in the balance sheet, on a pre-tax basis. No penalties were accrued by the Company through September 30, 2010.

In June 2006, the Companies filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU was selected to receive $101 million in tax credits. A final IRS certification required to obtain the investment tax credits was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credits, which includes a full depreciation basis adjustment for the amount of the credits. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $6 and $17 million during the three and nine months ended September 30, 2009, decreasing current federal income taxes. As of December 31, 2009 KU had recorded its maximum credit of $101 million. The income tax expense impact from amortizing these credits over the life of the related property will begin when the facility is placed in service, which is expected to occur by year end.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. The plaintiffs voluntarily dismissed their complaint in August 2010.

A reconciliation of differences between the income tax expense at the statutory U.S. federal income tax rate and the Company's actual income tax expense follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Statutory federal income tax expense	$ 30	$ 37	$ 72	$ 52
State income taxes — net of federal benefit	3	4	8	4
Dividends received deduction related to EEI investment	—	—	—	(3)
Other differences — net	(1)	(2)	(4)	(4)
Income tax expense	$ 32	$ 39	$ 76	$ 49
Effective income tax rate	37.2%	37.1%	37.1%	33.1%

The amounts shown in the table above are rounded to the nearest $1 million; however, the effective income tax rates are based on actual underlying amounts. Other differences — net includes the qualified production activities deduction and excess deferred taxes on depreciation.

The effective tax rate for the nine months ended September 2010 was higher than the rate for the nine months ended 2009 due to state income taxes — net of federal benefit being lower due to a coal credit recorded in 2009 and a lower dividends received deduction primarily due to the lack of EEI dividends in 2010.

Note 8 — Short-Term and Long-Term Debt

KU's long-term debt includes $228 million of pollution control bonds that are classified as current portion of long-term debt because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include:

	(In millions)
Mercer Co. 2000 Series A, due May 1, 2023, variable%	$ 13
Carroll Co. 2002 Series A, due February 1, 2032, variable%	21
Carroll Co. 2002 Series B, due February 1, 2032, variable%	2
Carroll Co. 2008 Series A, due February 1, 2032, variable%	78
Mercer Co. 2002 Series A, due February 1, 2032, variable%	8
Muhlenberg Co. 2002 Series A, due February 1, 2032, variable%	2
Carroll Co. 2004 Series A, due October 1, 2034, variable%	50
Carroll Co. 2006 Series B, due October 1, 2034, variable%	54
	$228

The average annualized interest rates for these bonds follow:

	September 30, 2010	September 30, 2009
Three months ended	0.37%	0.51%
Nine months ended	0.36%	0.65%

Pollution control bonds are obligations of KU issued in connection with tax-exempt pollution control bonds issued by counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the counties that equate to the debt service due from the counties on the related pollution control bonds. The loan agreement is an unsecured obligation of the Company. Debt issuance expense is capitalized in either regulatory assets or current or long-term other assets and amortized over the lives of the related bond issues, consistent with regulatory practices.

In October 2010, KU's pollution control bonds were converted from unsecured debt to debt which is collateralized by first mortgage bonds. Also in October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the Company's issuer rating as a result of the pending acquisition by PPL.

Several of the KU pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At September 30, 2010, KU had an aggregate $351 million of outstanding pollution control indebtedness, of which $96 million is in the form of insured auction rate securities wherein interest rates are reset every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. Since 2008, the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture.

The average annualized interest rates on the auction rate bonds follow:

	September 30, 2010	September 30, 2009
Three months ended	0.61%	0.34%
Nine months ended	0.50%	0.51%

The instruments governing these auction rate bonds permit KU to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In June 2009, one national rating agency downgraded the credit rating of an insurer of the Company's bonds. As a result, the national rating agency downgraded the rating on the Carroll County 2002 Series C bond. The national agency's rating of this bond is now based on the rating of the Company rather than the rating of the insurer since the Company's rating is higher.

The Company participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) up to $400 million. Details of the balances are as follows:

	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
	(In millions)			
September 30, 2010	$400	$61	$339	0.28%
December 31, 2009	$400	$45	$355	0.20%

E.ON U.S. maintained revolving credit facilities totaling $313 million at September 30, 2010 and December 31, 2009, to ensure funding availability for the money pool. At September 30, 2010, one facility, totaling $150 million, was with E.ON North America, Inc. while the remaining line, totaling $163 million, was with Fidelia; both are affiliated companies. The balances are as follows:

	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
	(In millions)			
September 30, 2010	$313	$181	$132	1.44%
December 31, 2009	$313	$276	$ 37	1.25%

As of September 30, 2010, the Company maintained a $35 million bilateral line of credit, maturing in June 2012, with an unaffiliated financial institution. At September 30, 2010, there was no balance outstanding under this facility. The Company also maintains letter of credit facilities that support $195 million of the $228 million of bonds that can be put back to the Company. Should the holders elect to put the bonds back and they cannot be remarketed, the letter of credit would fund the investor's payment.

There were no redemptions or issuances of long-term debt year-to-date through September 30, 2010. KU was in compliance with all debt covenants at September 30, 2010 and December 31, 2009. See Note 1, General, for certain debt refinancing and associated transactions which are anticipated by KU in connection with the PPL acquisition and Note 10, Related Party Transactions, for long-term debt payable to affiliates.

Note 9 — Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2, Rates and Regulatory Matters), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in the Company's Annual Report for the year ended December 31, 2009 (including, but not limited to Note 2, Rates and Regulatory Matters; Note 9, Commitments and Contingencies; and Note 12, Subsequent Events, contained therein). See the Company's Annual Report regarding such commitments or contingencies.

Letters of Credit

KU has provided letters of credit as of September 30, 2010 and December 31, 2009, for on-balance sheet obligations totaling $198 million to support bonds of $195 million and a letter of credit for off-balance sheet obligations totaling less than $1 million to support certain obligations related to workers' compensation.

Owensboro Contract Litigation and Contract Termination

In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit against KU concerning a long- term power supply contract (the "OMU Agreement") with KU. In May 2009, KU and OMU executed a settlement agreement resolving the matter on a basis consistent with prior court rulings, and the Company has received the agreed settlement amounts. Pursuant to the settlement's operation, the OMU agreement terminated in May 2010. In connection with such termination, KU has recorded a net receivable totaling $4 million reflecting its estimate of remaining adjustments concerning prior accruals. The parties are engaged in discussions to resolve those remaining adjustments.

Construction Program

KU had approximately $167 million of commitments in connection with its construction program at September 30, 2010.

In June 2006, the Companies entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. During 2009 and 2010, the Companies received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. In September 2010, the Companies and construction contractor agreed to a settlement to resolve certain force majeure and excusable event claims occurring through July 2010, under the TC2 construction contract, which settlement provided for a limited, negotiated extension of the contractual commercial operations date and/or relief from liquidated damages calculations. During commissioning activities in the second and third quarters, separate delays have occurred related to burner malfunctions and an excitation transformer failure. Certain temporary or permanent repairs for both matters have been completed, are underway or are planned for appropriate future outage periods. Commis- sioning steps resumed in October 2010, and a revised commercial operations date is currently expected by year end. The parties are analyzing the treatment of these additional delays under the liquidated damages provisions of the construction agreement. The Companies cannot currently estimate the ultimate outcome of these matters, including the extent, if any, that such outcome may result in materially increased costs for the construction of TC2, further changes in the TC2 construction completion or commercial operation dates or potential effects on levels of power purchases or wholesale sales due to such changed dates.

<u>TC2 Air Permit</u>

The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims, but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an Order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the EPA objections. In March 2010, the environmental groups submitted a petition to the EPA to object to the permit revision, which is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

<u>Thermostat Replacement</u>

During January 2010, the Companies announced a voluntary plan to replace certain thermostats, which had been provided to customers as part of the Companies' demand reduction programs, due to concerns that the thermostats may present a safety hazard. Under the plan, the Companies have replaced approximately 90% of the estimated 14,000 thermostats that need to be replaced. Total estimated costs associated with the replacement program are $2 million. However, the Companies cannot fully predict the ultimate outcome of the replacement program or other effects or developments which may be associated with the thermostat replacement matter at this time.

<u>OVEC</u>

KU holds a 2.5% investment interest in OVEC with 10 other electric utilities. KU is not the primary beneficiary; therefore the investment is not consolidated into the Company's financial statements, but is recorded on the cost basis. OVEC is located in Piketon, Ohio, and owns and operates two coal-fired power plants, Kyger Creek Station in Ohio, and Clifty Creek Station in Indiana. KU is contractually entitled to 2.5% of OVEC's output, approximately 55 Mw of generation capacity. Pursuant to the OVEC power purchase contract, the Company may be conditionally responsible for a 2.5% pro-rata share of certain obligations of OVEC under defined circumstances. These contingent liabilities may include unpaid OVEC indebtedness as well as shortfall amounts in certain excess decommissioning costs and post-retirement benefits other than pension. KU's potential proportionate share of OVEC's September 30, 2010 outstanding debt was $35 million.

<u>Environmental Matters</u>

The Company's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety. As indicated below and summarized at the conclusion of this section, evolving environmental regulations will likely increase the level of capital and operating and maintenance expenditures incurred by the Company during the next several years. Based on prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify “nonattainment areas” within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final “NOx SIP Call” rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR.

In July 2008, a federal appeals court issued a ruling finding deficiencies in the CAIR and vacating it. In December 2008, the Court amended its previous Order, directing the EPA to promulgate a new regulation but leaving the CAIR in place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Companies’ compliance plans relating thereto due to the interconnection of the CAIR with such associated programs.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS standards for nitrogen dioxide (“NO_2”) and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS standards, KU’s power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions.

In July 2010, the EPA issued the proposed CATR, which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012, and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on an alternative approach which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional “transport” rules to address compliance with revised NAAQS standards for ozone and particulate matter which will be issued by the EPA in the future, as discussed below.

Hazardous Air Pollutants. As provided in the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010, and final reductions due by 2018. The CAMR provided for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a “co-benefit” of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has entered into a consent decree requiring it to promulgate a utility Maximum Achievable Control Technology rule to replace the CAMR with a proposed rule due by March 2011, and a final rule due by November 2011. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations.

Acid Rain Program. The Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to “acid rain” conditions in the northeastern U.S. The

Clean Air Act also contains requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its Clean Air Visibility Rule detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the remand of the CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU's strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as, using accumulated emission allowances and fuel switching to defer certain additional capital expenditures. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, KU installed additional NOx controls, including SCR technology, during the 2000 through 2009 time period at a cost of $221 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve currently mandated emissions reductions, KU expects to incur additional capital expen- ditures totaling approximately $285 million during the 2010 through 2012 time period for pollution controls including FGD and SCR equipment and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by the Company for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

GHG Developments. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. As discussed below, legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs, including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are on-going. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. In Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations are scheduled to meet in Cancun, Mexico in late 2010 to continue negotiations toward a binding agreement.

GHG Legislation. KU is monitoring on-going efforts to enact GHG reduction requirements and require- ments governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which is a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill would provide for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020 and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would initially be allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would also establish a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contains additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act, which is largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raises the emissions reduction target for 2020 to 20% below 2005 levels and does not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. In 2010, Senators Kerry and Lieberman and others have undertaken additional work to draft GHG legislation but have introduced no bill in the Senate to date. In July 2010, Senate Majority Leader Reid announced that he did not anticipate that GHG legislation would be brought to the Senate floor in the current session. The Company is closely monitoring the progress of pending energy legislation, but the prospect for passage of comprehensive GHG legislation in 2010 is uncertain.

GHG Regulations. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities will be required to submit annual reports commencing with calendar year 2010. In May 2010, the EPA issued a final GHG "tailoring" rule requiring new or modified sources with GHG emissions equivalent to at least 75,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the rule. The final rule will apply to new and modified power plants beginning in January 2011. The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations.

GHG Litigation. A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. In March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing but subsequently denied the appeal due to the lack of a quorum. The appellate ruling leaves in effect the lower court ruling dismissing the plaintiffs' claims. The petitioners filed a petition for a writ of mandamus with the Supreme Court in August 2010. The Comer complaint alleges that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the indirect parent of the Companies, was included as a defendant in the complaint but has not been subject to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. The Companies are currently unable to predict further developments in the Comer case and continue to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to their operations.

Ghent Opacity NOV. In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. The Company is not able to estimate the outcome or potential effects of these matters, including

whether substantial fines, penalties or remedial measures may result.

Ghent New Source Review NOV. In March 2009, the EPA issued an NOV alleging that KU violated certain provisions of the Clean Air Act's rules governing new source review and prevention of significant deterioration by installing FGD and SCR controls at its Ghent generating station without assessing potential increased sulfuric acid mist emissions. KU contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued a Section 114 information request seeking additional information on this matter. In March 2010, the Company received an EPA settlement proposal providing for imposition of additional permit limits and emission controls and anticipates continued settlement negotiations with the EPA. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination on the Company's financial position or results of operations.

Ash Ponds and Coal-Combustion Byproducts. The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the Tennessee Valley Authority's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including KU, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of KU's impoundments, which the EPA found to be in satisfactory condition. In June 2010, the EPA published proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts.

Water Discharges and PCB Regulations. The EPA has also announced plans to develop revised effluent limitation guidelines governing discharges from power plants and standards for cooling water intake structures. The EPA has further announced plans to develop revised standards governing the use of polychlorinated biphenyls ("PCB") in electrical equipment. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized.

Impact of Pending and Future Environmental Developments. As a company with significant coal-fired generating assets, KU will likely be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. These evolving environmental regulations will likely require an increased level of capital expenditures and increased incremental operating and maintenance costs by the Company over the next several years. Due to the uncertain nature of the final regulations that will ultimately be adopted by the EPA, including the reduction targets and the deadlines that will be applicable, the Company cannot finalize estimates of the potential compliance costs, but should the final rules incorporate additional emission reduction requirements, require more stringent emissions controls or implement more stringent byproducts storage and disposal practices, such costs will likely be significant. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.7 billion range over the next 10 years, although final costs may substantially vary. With respect to potential developments in water discharge, revised PCB standards or GHG initiatives, costs in such areas cannot be estimated due to the preliminary status or uncertain outcome of such developments, but would be in addition to the above amount and could be substantial. Ultimately, the precise impact on the Company's operations of these various environmental developments cannot be determined prior to the finalization of such requirements. Based on prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

TC2 Water Permit. In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County generating station. In October 2010, the hearing officer issued a report and recommended order providing for dismissal of the claims raised by the petitioners. Until such time as the Secretary issues a final order of the agency and all appeals are exhausted, the Company is unable to predict the outcome or precise impact of this matter.

General Environmental Proceedings. From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable envi- ronmental laws and regulations. Such matters include a prior Section 114 information request from the EPA relating to new-source issues at KU's Ghent unit 2; completed settlement with state regulators regarding compliance with particulate limits in the air permit for KU's Tyrone generating station; remediation activities for or other risks relating to elevated PCB levels at existing properties; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; and claims regarding the GHG emissions from the Company's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 10 — Related Party Transactions

KU, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between KU and E.ON U.S. subsidiaries are eliminated on consolidation of E.ON U.S. Transactions between KU and E.ON subsidiaries are eliminated on consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under the Public Utility Holding Company Act of 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Intercompany Wholesale Sales and Purchases

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the two Companies. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

These sales and purchases are included in the statements of income as operating revenues, power purchased expenses and other operation and maintenance expenses. KU's intercompany electric revenues and power purchased expense were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Electric operating revenues from LG&E.	$ 3	$ 2	$13	$18
Power purchased and related operations and maintenance expenses from LG&E.	22	22	71	82

Interest Charges

See Note 8, Short-Term and Long-Term Debt, for details of intercompany borrowing arrangements. Inter- company agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's interest expense to affiliated companies was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Interest on Fidelia loans	$18	$18	$55	$51

Interest expense paid to E.ON U.S. on the money pool arrangement was less than $1 million for the three and nine months ended September 30, 2010 and 2009.

Dividends

In September 2010, the Company paid dividends of $50 million to its common shareholder, E.ON U.S.

Capital Contributions

In March and June 2009, the Company received capital contributions of $50 million and $25 million, respectively, from its common shareholder, E.ON U.S.

Other Intercompany Billings

Servco provides the Company with a variety of centralized administrative, management and support services. These services include payroll taxes paid by Servco on behalf of KU, labor and burdens of Servco employees performing services for KU, coal purchases and other vouchers paid by Servco on behalf of KU. The cost of these services is directly charged to the Company, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, the Companies provide services to each other and to Servco. Billings between the Companies relate to labor and overheads associated with union and hourly employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to Servco include cash received by Servco on behalf of KU, primarily tax settlements, and other payments made by the Company on behalf of other non-regulated businesses which are reimbursed through Servco.

Intercompany billings to and from KU were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Servco billings to KU	$64	$43	$181	$121
KU billings to LG&E	—	16	1	63
LG&E billings to KU	28	—	47	—
KU billings to Servco	11	3	11	5

Intercompany Balances

The Company had the following balances with its affiliates:

	September 30, 2010	December 31, 2009
	(In millions)	
Accounts receivable from E.ON U.S.	$ —	$ 9
Accounts payable to LG&E	17	53
Accounts payable to Servco	18	20
Accounts payable to E.ON U.S.	18	—
Accounts payable to Fidelia	18	15
Notes payable to E.ON U.S.	61	45
Long-term debt to Fidelia (including current portion of $33 million)	1,331	1,331

Note 11 — Subsequent Events

Subsequent events have been evaluated through October 29, 2010, the date of issuance of these statements, and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

On October 29, 2010, KU's pollution control bonds were converted from unsecured debt to debt which is collateralized by first mortgage bonds. See Note 1, General, and Note 8, Short-Term and Long-Term Debt.

On October 26, 2010, the FERC issued an Order approving the acquisition of E.ON U.S. by PPL. See Note 1, General.

On October 19, 2010 and October 21, 2010, respectively, the Virginia Commission and Tennessee Regulatory Authority issued Orders approving the acquisition of E.ON U.S. by PPL. On the same dates, KU received Virginia Commission and Tennessee Regulatory Authority approvals to complete certain refinancing transactions in connection with the anticipated PPL acquisition and other business factors. See Note 1, General, and Note 8, Short-Term and Long-Term Debt.

$1,500,000,000

Kentucky Utilities Company

a PPL company

$250,000,000 1.625% First Mortgage Bonds due 2015
$500,000,000 3.250% First Mortgage Bonds due 2020
$750,000,000 5.125% First Mortgage Bonds due 2040

Offering Memorandum
November 8, 2010

Joint Book-Running Managers

BofA Merrill Lynch
Credit Suisse
BNP PARIBAS
Mitsubishi UFJ Securities
RBS
Scotia Capital

Co-Managers

BBVA Securities
RBC Capital Markets
Santander
SunTrust Robinson Humphrey
The Williams Capital Group, L.P.