LG&E KU
PPL companies

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LG&E and KU Energy LLC
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Rick E. Lovekamp
Manager - Regulatory Affairs
T 502-627-3780
F 502-627-3213
rick.lovekamp@lge-ku.com

Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

April 21, 2011

RE: ***The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company***
Case No. 2011-00____

Dear Mr. DeRouen:

Please find enclosed and accept for filing pursuant to 807 KAR 5:058 an original and ten (10) copies of Louisville Gas and Electric Company's (LG&E) and Kentucky Utilities Company's (KU) 2011 Joint Integrated Resource Plan (IRP).

Also, enclosed are an original and ten (10) copies of a Petition for Confidential Protection regarding three general categories: (i) information regarding projected fuel costs and other production costs (capital/operation and maintenance); (ii) information regarding projected sales prices and revenue requirements; and (iii) infrastructure information that, if publicly released, could threaten public safety (transmission related information). Therefore, the Companies are filing with the Commission one (1) copy of the IRP highlighting the information for which confidential treatment is sought.

Should you have any questions regarding the enclosed, please contact me.

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

cc: Hon. Dennis Howard II
Hon. Michael L. Kurtz

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VOLUME II, Technical Appendix

VOLUME III, Technical Appendix

This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

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4. FORMAT

4.(1) Organization

This plan is organized by using the Section and Subsection numbers found in the Administrative Regulation 807 KAR 5:058, "Integrated Resource Planning by Electric Utilities." This report is filed with the Public Service Commission of Kentucky in compliance with the aforementioned regulation.

The format of the report is outlined below.

I. Volume I

1) Table of Contents
2) Section 4. Format
3) Section 5. Plan Summary
4) Section 6. Significant Changes
5) Section 7. Load Forecasts
6) Section 8. Resource Assessment and Acquisition Plan
7) Section 9. Financial Information

II. Volume II. Technical Appendix

1) The U.S. Economy, The 30-Year Focus, First Quarter 2010, IHS Global Insight
2) KU & LG&E Hourly Demand Forecast Methodology
3) KU, LG&E, & ODP: Commercial Use-per-Customer Models
4) KU, LG&E, & ODP: Residential Use-per-Customer Models

III. Volume III. Technical Appendix

1) Recommendations in PSC Staff Report on the Last IRP Filing
2) Analysis of Supply-Side Technology Alternatives
3) LG&E and KU 2011 Reserve Margin Study
4) 2011 Optimal Expansion Plan Analysis
5) Transmission Information

4.(2) Identification of individuals responsible for preparation of the plan

Lonnie Bellar, VP State Regulation and Rates

Michael Hornung, Manager Energy Efficiency Planning and Development

Gregory Lawson, Manager Sales Analysis and Forecasting

Rick Lovekamp, Manager Regulatory Affairs

Gary Revlett, Director Environmental Affairs

Charles Schram, Director Energy Planning, Analysis & Forecasting

David Sinclair, VP Energy Marketing

Allyson Sturgeon, Senior Corporate Attorney

Stuart Wilson, Manager Generation Planning

B. Keith Yocum, Manager Transmission Strategy and Planning

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5. PLAN SUMMARY

5.(1) Description of the utility, its customers, service territory, current facilities, and planning objectives.

Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") are investor-owned public utilities supplying electricity and natural gas to customers primarily in Kentucky. Both KU and LG&E are subsidiaries of LG&E and KU Energy LLC ("LKE"), which is a subsidiary of PPL Corporation (NYSE: PPL). PPL Corporation ("PPL") acquired LKE in November 2010 from E.ON AG (Frankfurt: EOA), who had owned the LKE companies since July 2002. In connection with the acquisition, LKE, which was formerly known as "E.ON U.S. LLC," was renamed "LG&E and KU Energy LLC," while the utility subsidiaries KU and LG&E maintained their existing names and brands. As the owners and operators of interconnected electric generation, transmission, and distribution facilities, KU and LG&E (the "Companies") achieve economic benefits through operation as a single interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities.

The mandate for the Companies' Integrated Resource Plan ("IRP") is to meet future energy requirements within their service territories at the lowest possible cost consistent with reliable supply. Serving more than 939,000 electricity customers via a transmission and distribution network consisting of 27,600 miles of lines and conduit, KU and LG&E have a joint net summer generation capacity of 8,001 megawatts ("MW") as shown in Table 5.(1)-1. Based in Lexington, KU supplies electric service in an area that covers approximately 6,600 noncontiguous square miles and includes seventy-seven counties in Kentucky, five counties in southwestern Virginia that are serviced by Old Dominion Power Company ("ODP"), and five customers in Tennessee. KU also sells wholesale electricity for resale to twelve municipalities in Kentucky. LG&E, an electric and natural gas utility, serves customers in an area that covers approximately 700 square miles and includes the Louisville metropolitan area and seventeen surrounding counties.

The Companies' retail customers include all customers served under the following service classes: residential, general service (small commercial and industrial), large commercial, large industrial (large power), public authority and street lighting. Among the industries included in the service territory are coal mining, automotive and related industries, agriculture, primary metals processing, chemical processing, pipeline transportation, and the manufacture of electrical and other machinery and of paper and paper products.

The Companies' power generating system consists of nineteen coal-fired units operated at seven different steam generating stations: E.W. Brown, Cane Run, Ghent, Green River, Mill Creek, Trimble County and Tyrone. Gas-fired and/or oil-fired combustion turbines supplement the system during peak periods. The system is further augmented by hydroelectric facilities at Dix Dam and Ohio Falls. The generating units for KU and LG&E are summarized in Table 5.(1)-1. (See Table 8.(3)(b) in Section 8 for a detailed listing.)

Table 5.(1)-1
Generating Unit Totals

	2011 Summer Net Capacity (MW)	2011/12 Winter Net Capacity (MW)
KU		
Coal	3,285	3,345
Gas	1,463	1,613
Hydro	26	28
Total KU	**4,774**	**4,986**
LG&E		
Coal	2,522	2,548
Gas	652	728
Hydro	52	35
Total LG&E	**3,226**	**3,311**
Total		
Coal	5,808	5,893
Gas	2,115	2,341
Hydro	78	63
Total	**8,001**	**8,297**

The Companies' net summer generating capacity in 2011 is planned to be 8,001 MW, including the new coal unit at the Trimble County Station. In addition to the capacity owned by the Companies, both LG&E and KU have purchase agreements in place with Ohio Valley Electric Corporation ("OVEC"). In total, the Companies currently receive 8.13 percent of the OVEC capacity and energy for an additional 155 MW at the time of summer peak. Further description of the OVEC sponsorship is contained in Section 5.(4). The Companies' highest combined system peak demand of 7,175 MW occurred on August 4, 2010, at hour ending 15:00 EST. At that time, LG&E reached its highest peak demand at 2,852 MW. KU experienced its highest summer system peak demand of 4,354 MW on the same day, at hour ending 13:00 EST. However, KU set its all-time system peak on January 16, 2009, at hour ending 09:00 EST with 4,640 MW.

The Companies have an ongoing resource planning process and this report represents only one snapshot in time of the process which is fundamental to all corporate planning. The various sections of this report define ongoing and planned activities that collectively make up this process. Certain assumptions are made in these planning decisions, and as such, are subject to various degrees of risk and uncertainty.

The economics and practicality of supply-side and demand-side options are examined as part of the integrated planning process in order to forecast the Companies' least cost options to meet forecasted customer needs. The Companies' resource planning process is comprised of the following: 1) establishment of a reserve margin criterion, 2) assessment of the adequacy of existing generating units and purchased power agreements, 3) assessment of potential purchased power market agreements, 4) assessment of demand-side options, 5) assessment of supply-side options, and 6) development of the optimal economic plan from the available resource options. Even though the IRP represents the Companies' analysis of the best options to meet customer needs at this given point in time, this forecast is reviewed and re-evaluated prior to implementation.

The Companies reviewed and considered the Commission Staff Report on the 2008 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company dated October 2009 (Case No. 2008-00148) while preparing this IRP. The Companies have addressed the suggestions and recommendations contained in the Staff report. A summary of the ways in which these suggestions and recommendations were addressed is provided in the report titled *Recommendations in PSC Staff Report on the Last IRP Filing* contained in Volume III, Technical Appendix.

5.(2) Description of models, methods, data, and key assumptions used to develop the results contained in the plan;

Demand and Energy Forecast

The production of a robust forecast of system energy requirements and peak demand is a prerequisite for efficient planning and control of utility operations. The Companies' goals are to provide adequate and reliable service to their customers at the lowest reasonable cost, and to achieve equitable cost allocation between customers based on the costs of providing service. Decisions on the selection, size and timing of capacity additions in the various components of the supply chain – including power plants, transmission lines, and substations – are directly dependent on sales trends and characteristics as identified in the long-term load forecast.

The modeling techniques employed by the Companies allow energy and demand forecasts to be tailored to address the unique characteristics of the KU and LG&E service territories. New forecasting approaches are continually evaluated to optimize all aspects of the exercise.

Energy forecasts for KU and LG&E are developed using the same basic methodologies. The energy forecasts from each utility are used as inputs to a consistent demand forecasting methodology that generates individual and combined company demand forecasts. The remainder of this section addresses at a summary level the models, methods, data and key assumptions in developing the energy and demand forecast for the 2011 IRP.

Models and Methods

The Companies' forecasting approach is based on econometric modeling of energy sales by customer class, but also incorporates specific intelligence on the prospective energy requirements of the utility's largest customers. Econometric modeling captures the (observed) statistical relationship between energy consumption – the dependent variable – and one or more independent explanatory variables such as the number of households or the level of economic activity in the service territory. Forecasts of electricity sales are then derived from a projection of the independent variable(s).

This widely-accepted approach can readily accommodate the influences of national, regional and local (service territory) drivers of utility sales. This approach may be applied to forecast customer numbers, energy sales, or use-per-customer. The statistical relationships will vary depending upon the jurisdiction being modeled and the class of service. For LG&E, only one jurisdiction is modeled, Kentucky-retail. The KU energy forecast identifies three separate jurisdictional groups: Kentucky-retail, Virginia-retail, and wholesale sales (to 12 municipally-owned utilities in Kentucky). The distribution of KU sales by jurisdiction in 2010 was: 86 percent Kentucky-retail; 5 percent Virginia-retail; and 9 percent wholesale. Within each jurisdiction, the forecast typically distinguishes several classes of customers including residential, commercial, and industrial.

The econometric models used to produce the forecast passed two critical tests. First, the explanatory variables of the models were theoretically appropriate and have been widely used in electric utility forecasting. Second, inclusion of those explanatory variables produced statistically-significant results that led to an intuitively reasonable forecast. In other words, the models were proven theoretically and empirically robust to explain the behavior of the KU and LG&E customer and sales data.

Sales to several of KU's and LG&E's largest customers are forecast based on information obtained through direct discussions with these customers. These regular communications allow the Companies to directly adjust sales expectations given the first-hand knowledge of the production outlook for these companies.

The modeling of residential and commercial sales also incorporates elements of end-use forecasting – covering base load, heating and cooling components of sales – which recognize expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

Once complete, the KU and LG&E energy forecasts are converted from a billed to calendar basis and associated with class-specific load profiles to create hourly sales. These are then adjusted for company uses and losses. The resulting estimate of hourly energy requirements is used to generate annual, seasonal, and monthly peak demand forecasts.

A more detailed description of the forecasting models, methods, and data used to develop the forecast is contained in Section 7 of this report.

Data

Data inputs to the forecasting process for both KU and LG&E come from a variety of external and internal sources. The national outlook for U.S. Gross Domestic Product, industrial production and consumer prices are key macro-level variables that establish the broad market environment within which KU and LG&E operate. Local influences include trends in population, household formation, employment, personal income, and cost of service provision (the 'price' of electricity). National, regional and state level macroeconomic and demographic forecast data are provided by reputable economic forecasting consultants (Global Insight).

Weather data for each service territory is provided by the National Climatic Data Center ("NCDC"), a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. Itron provides regional databases with information from the Energy Information Administration ("EIA") that supports the modeling of appliance saturation and efficiency trends and customer choice. The retail electric price forecast and load profile/load factor data for both utilities are determined internally.

As mentioned previously, sales to several large customers for both KU and LG&E are forecast based on information provided by these customers to the Companies. Historical sales data for these customers and for the respective class forecasts are obtained via extracts from the Companies' Customer Care Solutions ("CCS") system. Figure 5.(2)-1 illustrates the external and internal data sources used to drive the Companies' forecasts.

Figure 5.(2)-1
Data Inputs to KU & LG&E Customer, Sales, and Demand Forecasts

<u>External</u>

Global Insight

National Economic/
Demographic Factors

Global Insight

County & State
Economic/

NCDC

Temperature Data for
Lexington, Louisville,
and Bristol, TN

Itron/EIA

Appliance Efficiency &
Saturation Assumptions

<u>Internal</u>

Retail Electric Price
Forecast

LG&E/KU Customer
and Sales History by
Rate Class from CCS
Systems

Individual Large
Customer Information

Service Territory
Appliance Saturation
Surveys

Class-Specific Load
Profiles from Load
Research data & Load
Factor Assumptions

Key Assumptions

Following is a summary of key assumptions from Global Insight's 2010 Long-Term Macro Forecast, used by the Companies as macroeconomic background for the energy sales forecast in the 2011 IRP. A copy of this forecast is attached as part of the Technical Appendix in Volume II.

- *Trend Scenario*:

  The trend scenario is a projection that assumes no major economic mishaps between now and 2040. The projection is best described as depicting the mean of all possible paths the economy could follow, absent of any major disruptions such as oil price shocks or major changes in policy. The trend scenario between 2011 and 2040 predicts GDP growth slightly below the historical rate for the last thirty years. Personal consumption and government spending are expected to fall slightly as well in comparison to the thirty year historical trend. There is an expected improvement in business investment along with an improvement in the balance of trade with exports growing at a faster rate than imports.

- *Demographics*:

  The trend scenario provides a demographic prediction which is based on the predictions provided by the Census Bureau. Global Insight predicts slowing

population growth over the next thirty years. Increased life spans for both men and women point to an aging population.

- *Output*:

  Growth in annual real U.S. Gross Domestic Product was projected to average 2.6 percent over the forecast period.

Energy Independence and Security Act of 2007 and American Recovery and Reinvestment Act of 2009

The Energy Independence and Security Act of 2007 ("EISA 2007") was signed into law by President Bush in December 2007. The provisions in EISA 2007 are primarily designed to increase energy efficiency and the availability of renewable energy. The Companies' energy sales will be impacted primarily by provisions in the act that tightened lighting and appliance efficiency standards as well as fostered the development of new building and commercial equipment standards. EISA 2007 efficiencies have been embedded into the models to construct the small commercial and residential forecasts.

The American Recovery and Reinvestment Act of 2009 ("ARRA") was introduced by President Obama in February 2009. The provisions in the ARRA relative to energy are intended to increase energy efficiency, research and development of renewable energy and alternative fuels, and research and development of new technology such as smart grid infrastructure. The Companies' electricity sales will be impacted primarily by provisions in the act that make efforts to weatherize residential, commercial, and government buildings. The 2011 IRP incorporates the impact of the new weatherization incentives such as tax cuts, funding, loans, and block grants. In addition, previous government mandates and general increased awareness of energy efficiency ideas have been incorporated in the 2011 IRP.

Resource Assessment

Both the economics and practicality of supply-side and demand-side options are carefully examined in the planning decision-making process in order to develop an IRP which meets customers' expected needs. The Companies continue to use the Strategist® program for resource expansion studies. Strategist® contains several modules which may be executed in various ways to evaluate system resource expansion alternatives. Strategist® is a proprietary computer model developed by Ventyx[1], which integrates the supply-side, demand-side, and environmental compliance alternatives to produce a ranked number of plans that meet the prescribed reliability criteria.

The following sensitivity analyses were performed as a part of this resource assessment:

- Higher customer load requirements forecast
- Lower customer load requirements forecast
- No new environmental regulations

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[1] Ventyx was acquired by power and automation technology group ABB in June 2010.

- Gas cost (breakeven)
- Capital cost (breakeven)

In the resource assessment, each resource option is selected for optimal performance at specific levels of utilization. Alternative load growth scenarios may have a significant impact on the selection of an optimal technology, type and size; therefore, three load forecasts are developed. The three forecasts show an expected system load growth case (base case); a case in which system load growth exceeds expected growth (high case); and, a case in which system load growth is less than expected (low case). The three load forecasts were analyzed as part of the IRP development.

The impact of impending environmental regulations is the most significant driver in this resource plan. Therefore, a sensitivity case was evaluated to identify the expansion plan expected without assumed environmental regulations.

The breakeven sensitivities help determine what data input or assumption changes would be necessary to make an uneconomical technology in the base case conditions economically equivalent. Coal and natural gas fuels are simulated in the supply side technology analysis as well as the resource optimization. A major change in future gas or coal prices can have a significant impact on both the selection of new units as well as upon the operation of existing units.

5.(3) Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts;

Combined Company

Combined Company History

Table 5.(3)-1 presents historical data on Combined Company customers, sales, energy requirements[2], and peak demand. On a Combined Company basis, the number of native electric customers increased from 925,251 in 2006 to 940,331 in 2010, an average annual growth rate of 0.4 percent. Actual sales for KU and LG&E rose from 33,550 gigawatt-hours ("GWh") in 2006 to 35,238 GWh in 2010, increasing at an average annual growth rate of 1.2 percent. On a weather-normalized basis, average sales growth was flat during this period, which included the economic recession beginning in 2008. Combined energy requirements grew from 35,070 GWh in 2006 to 35,382 GWh in 2010. Peak demand fluctuated over the 2006-2010 period. On an actual basis, peak demand increased from 6,863 MW in 2006 to 7,175 MW in 2010. The reduced demands in 2008 and 2009 were primarily the result of mild summer weather; the peak demands for these years occurred in the winter months. The peak demands for 2006, 2007, and 2010 occurred in the summer months. On a weather-normalized basis, the system peak increased by an annual growth rate of 0.4 percent from 2006 to 2010.

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[2] Energy requirements represent sales plus transmission and distribution losses.

Table 5.(3)-1

Combined Company: Historical Customer Numbers, Calendar Sales, Energy Requirements and Peak Demand, 2006-2010

	2006	2007	2008	2009	2010
Customers	925,251	934,227	937,151	931,455	940,331
Sales (GWh)	33,550	35,221	34,189	32,576	35,238
Weather-Normalized Sales (GWh)	34,000	34,627	34,028	32,906	33,916
Energy Requirements (GWh)	35,070	35,238	35,102	33,912	35,382
Peak Demand (MW) [1,2]	6,863	7,132	6,357	6,555	7,175
Weather-Normalized Peak Demand (MW)	6,824	6,975	6,467	6,296	6,935

1. Includes impact of interruptible and curtailable loads.
2. 2008 and 2009 are winter peaks.

Combined Company Forecast

All forecasts of energy sales/requirements, peak demand, and use-per-customer assume normal weather – taken as the 20-year average of daily temperatures in each month. Table 5.(3)-2 presents the forecast for Combined Company customer numbers, sales and energy requirements, together with forecast annual growth rates. From 2011 to 2025, the number of Combined Company customers is forecast to grow at an average annual rate of 0.8 percent.

Combined Company sales and energy requirements, which do not include the impact of DSM programs, are expected to grow at an average annual rate of 1.6 percent over the period between 2011 and 2015. Over the remainder of the period (2015-2025), the average annual growth in sales and energy requirements declines slightly to 1.5 percent.

Table 5.(3)-2

Combined Company: Forecast Customer Numbers, Sales, and Energy Requirements

Year	Combined Company Customers	% Growth in Customers	Combined Company Sales Forecast (GWh)	% Growth in Energy Sales	Combined Company Requirements Forecast (GWh)	% Growth in Energy Requirements
2010	940,331		33,006		35,382	
2011	947,850	0.8%	33,912	2.7%	36,019	1.8%
2012	955,859	0.8%	34,511	1.8%	36,657	1.8%
2013	963,992	0.9%	35,076	1.6%	37,271	1.7%
2014	972,112	0.8%	35,530	1.3%	37,797	1.4%
2015	980,085	0.8%	36,097	1.6%	38,451	1.7%
2016	987,952	0.8%	36,615	1.4%	39,050	1.6%
2017	995,773	0.8%	37,074	1.3%	39,557	1.3%
2018	1,003,557	0.8%	37,611	1.4%	40,129	1.4%
2019	1,011,485	0.8%	38,219	1.6%	40,773	1.6%
2020	1,019,558	0.8%	38,835	1.6%	41,436	1.6%
2021	1,027,625	0.8%	39,342	1.3%	41,987	1.3%
2022	1,035,685	0.8%	39,940	1.5%	42,630	1.5%
2023	1,043,704	0.8%	40,477	1.3%	43,209	1.4%
2024	1,051,708	0.8%	41,172	1.7%	43,941	1.7%
2025	1,059,672	0.8%	41,775	1.5%	44,590	1.5%

Table 5.(3)-3 presents the Combined Company forecast for summer and winter season peak demand. The Combined Company demand forecast reflects the coincident peak of both utilities (KU & LG&E); the individual company peaks are not necessarily coincident. Combined Company native demand after industrial curtailments is forecast to grow from 6,976 MW in 2011 to 7,477 MW in 2015, a growth of 501 MW with an average annual growth rate of 1.7 percent. By 2025, Combined Company demand reaches 8,957 MW for a total increase from 2011 of 1,981 MW, with growth averaging 1.8 percent per year over the full forecast period. Combined Company curtailable load is estimated to be 115 MW in 2011 increasing to 126 MW in 2015 and remaining at that level for the duration of the forecast. From 2011 through 2015, the winter peak increases by 504 MW for an average growth rate of 1.9 percent. By 2025, the winter peak is forecast to increase by 1,709 MW with growth averaging 1.7 percent per year. Curtailable load for industrial customers in the winter is equivalent to the estimate for the summer.

Table 5.(3)-3

Combined Company Seasonal Peak Demand Forecast

Year	Combined Company Summer Peak Demand (MW) [1]	Percent Growth	Year	Combined Company Winter Peak Demand (MW) [1]	Percent Growth
2010	6,935	-	2009/10	6,110	-
2011	6,976	0.6%	2010/11	6,377	4.4%
2012	7,094	1.7%	2011/12	6,640	4.1%
2013	7,235	2.0%	2012/13	6,654	0.2%
2014	7,354	1.6%	2013/14	6,759	1.6%
2015	7,477	1.7%	2014/15	6,881	1.8%
2016	7,529	0.7%	2015/16	6,993	1.6%
2017	7,634	1.4%	2016/17	7,016	0.3%
2018	7,771	1.8%	2017/18	7,134	1.7%
2019	7,968	2.5%	2018/19	7,210	1.1%
2020	8,159	2.4%	2019/20	7,400	2.6%
2021	8,266	1.3%	2020/21	7,607	2.8%
2022	8,392	1.5%	2021/22	7,693	1.1%
2023	8,545	1.8%	2022/23	7,774	1.0%
2024	8,771	2.6%	2023/24	7,933	2.0%
2025	8,957	2.1%	2024/25	8,086	1.9%

2010 summer and 2010 and 2011 winter demands are weather-normalized actual values.

Kentucky Utilities Company

Kentucky Utilities History

From 2006 to 2010, KU calendar sales grew at an average annual rate of 1.5 percent on an actual basis and 0.3 percent on a weather-normalized basis. On an actual basis, recent growth has been most pronounced in the Residential class (3.3 percent on average since 2006) followed by the Public Authority revenue class (1.8 percent). The Industrial and Commercial classes have experienced lower growth since 2006 (0.7 percent and 0.6 percent, respectively). Virginia retail sales have remained relatively flat from 2006 through 2010. Recorded and weather-normalized sales by class are displayed in Table 5.(3)-4.

Table 5.(3)-4
KU Recorded and Weather-Normalized Sales by Class (GWh)

	2006	2007	2008	2009	2010
SYSTEM BILLED SALES:					
Recorded	20,831	21,625	21,139	20,011	21,921
Weather Normalized	21,041	21,393	21,050	20,206	21,291
SYSTEM USED SALES:					
Recorded	20,675	21,643	21,190	20,260	21,938
Weather Normalized	20,946	21,439	21,079	20,398	21,234
ENERGY REQUIREMENTS:					
Recorded	22,014	22,993	22,456	21,476	23,467
Weather Normalized	22,163	22,255	22,345	21,613	22,764
SALES BY CLASS:					
Residential	5,908	6,432	6,384	6,165	6,729
Commercial	4,270	4,577	4,520	4,319	4,365
Industrial	6,083	6,049	5,778	5,455	6,245
Lighting	52	54	56	52	54
Public Authorities	1,472	1,552	1,566	1,510	1,581
Requirement Sales for Resale	1,978	2,059	1,971	1,848	2,002
KENTUCKY Retail	19,764	20,723	20,275	19,349	20,976
VIRGINIA Retail	911	919	916	911	962
SYSTEM LOSSES	1,323	1,333	1,243	1,191	1,507
Utility Use	16	17	22	25	23
ENERGY REQUIREMENTS	22,014	22,993	22,456	21,476	23,467

Kentucky Utilities Forecast

Following is a summary of key assumptions made in Global Insight's 2010 Long-Term Macro Forecast, used by the Companies as macroeconomic background for the energy sales forecast in the 2011 IRP. A copy of this forecast is attached as part of the Technical Appendix in Volume II.

- *Trend Scenario:*

  The trend scenario is a projection that assumes no major economic mishaps between now and 2040. The projection is best described as depicting the mean of all possible paths the economy could follow, absent of any major disruptions such as oil price shocks or major changes in policy.

  The trend scenario between 2011 and 2040 predicts GDP growth slightly below the historical rate for the last thirty years. Personal consumption and government spending are expected to fall slightly as well in comparison to the thirty year historical trend. There is an expected improvement in business investment along with an improvement in the balance of trade with exports growing at a faster rate than imports.

- *Demographics:*

  The trend scenario provides a demographic prediction which is based on the predictions provided by the Census Bureau. Global Insight predicts slowing

population growth over the next thirty years. Increased life spans for both men and women point to an aging population.

- *Output:*

  Growth in annual real U.S. Gross Domestic Product was projected to average 2.6 percent over the forecast period.

KU Customer Growth and Energy Sales

Total KU energy sales are expected to grow at an average annual rate of 1.7 percent over the first five years of the forecast period (2011-2015). Over the entire forecast period (2011-2025), sales are expected to grow at an average annual rate of 1.6 percent. Table 5.(3)-5 shows the five- and fifteen-year average annual growth rates for each class of sales along with each class's relative share of 2010 sales.

Kentucky retail residential sales are forecast to increase at a 1.2 percent annual rate from 2011 to 2015. Residential growth is driven by a combination of customer growth and continued growth in use-per-customer due to the increasing penetration of electric heat. Kentucky retail commercial sales are forecast to increase at a 1.9 percent annual rate from 2011 to 2015, while Kentucky retail industrial sales are projected to average 2.6 percent growth. Strong growth by some of the larger industrial customers creates a relatively strong medium-term growth outlook for the industrial sector. Wholesale sales are forecast to grow at an average rate of 0.6 percent. Virginia sales are expected to increase only moderately, with 0.7 percent average growth.

Table 5.(3)-5

KU: Sales Structure and Forecast Growth Rates by Class

Class	Percent of 2010 Sales	Percent Annual Growth Rate 2011-2015	Percent Annual Growth Rate 2011-2025
RETAIL	**90.9%**		
Kentucky	**86.1%**		
Residential	3.3%	1.2%	1.5%
Commercial	0.6%	1.9%	1.7%
Industrial	0.7%	2.6%	1.8%
Public Authorities	1.8%	1.7%	1.4%
Lighting	0.3%	1.2%	1.2%
VIRGINIA	**4.8%**	**0.7%**	**0.8%**
WHOLESALE	**9.1%**	**0.6%**	**0.7%**
TOTAL COMPANY	**100%**	**1.7%**	**1.6%**

KU's forecast of total customers and energy sales is summarized in Table 5.(3)-6. From 2011-2015, sales are projected to grow at an average growth rate of 1.7 percent. Over the next five-year period (2016-2020), the average annual growth in sales is also 1.5 percent (see Section 6 for a more detailed discussion of ARRA 2009). Through the entire forecast horizon, sales are projected to grow at an annual rate of 1.6 percent.

Table 5.(3)-6

Total KU Customer and Calendar Sales Forecasts (GWh)

Year	Customers	% Growth in Customers	Baseline Energy Sales Forecast (GWh)	% Growth in Energy Sales
2010	544,463		21,234	
2011	548,612	0.8%	21,506	1.3%
2012	553,283	0.9%	21,940	2.0%
2013	557,989	0.9%	22,344	1.8%
2014	562,851	0.9%	22,646	1.4%
2015	567,338	0.8%	23,039	1.7%
2016	572,059	0.8%	23,372	1.4%
2017	576,398	0.8%	23,667	1.3%
2018	580,771	0.8%	24,010	1.5%
2019	585,158	0.8%	24,405	1.6%
2020	589,474	0.7%	24,793	1.6%
2021	593,700	0.7%	25,116	1.3%
2022	597,810	0.7%	25,506	1.6%
2023	602,046	0.7%	25,858	1.4%
2024	606,071	0.7%	26,317	1.8%
2025	610,131	0.7%	26,718	1.5%

Kentucky Utilities Peak Demand

KU's actual and weather-normalized peak demand from 2006 to 2010 are shown in Table 5.(3)-7. On a weather-normalized basis and after curtailment, KU's summer and winter peaks in 2006 were 4,102 MW and 4,178 MW respectively. In 2010, the weather-normalized summer peak was 4,202 MW. The weather-normalized KU winter peaks have ranged from 4,178 MW in 2005/06 to 4,570 MW in 2007/08.

Table 5.(3)-7

KU Recorded and Weather-Normalized Peak Load (MW)

	2006	2007	2008	2009	2010
SUMMER					
Actual	4,150	4,333	3,878	3,888	4,323
Normalized	4,102	4,210	4,074	4,001	4,202
	2005/2006	**2006/2007**	**2007/2008**	**2008/2009**	**2009/2010**
WINTER					
Actual	4,019	4,300	4,476	4,640	4,344
Normalized	4,178	4,342	4,570	4,461	4,282

Kentucky Utilities Peak Demand Forecast

The KU summer peak demand is forecast to increase at an average annual rate of 1.8 percent from 4,146 MW in 2011 to 5,361 MW in 2025, adding 1,215 MW over the period (see Table 5.(3)-8). From 2011 to 2015, the KU summer peak demand is forecast to increase from 4,146 MW to 4,497 MW, which represents an average annual growth of 2.0 percent. From 2016 to 2025, the summer peak demand is forecast to increase at an average annual rate of 1.9 percent from 4,522 MW to 5,361 MW, adding 839 MW. KU's curtailable load is estimated to be 66 MW for each summer period during the forecast.

Table 5.(3)-8

KU: Forecast Energy Requirements (GWh) and Peak Demand (MW)

Year	Baseline Output, GWh[1]	Percent Growth	Base Summer Peak, MW [2,3]	Percent Growth
2010	22,764		4,202	
2011	22,915	0.7%	4,146	-1.3%
2012	23,381	2.0%	4,237	2.2%
2013	23,821	1.9%	4,341	2.5%
2014	24,173	1.5%	4,417	1.7%
2015	24,625	1.9%	4,497	1.8%
2016	25,010	1.6%	4,522	0.6%
2017	25,340	1.3%	4,584	1.4%
2018	25,708	1.5%	4,663	1.7%
2019	26,127	1.6%	4,780	2.5%
2020	26,549	1.6%	4,895	2.4%
2021	26,907	1.3%	4,953	1.2%
2022	27,322	1.5%	5,022	1.4%
2023	27,706	1.4%	5,109	1.7%
2024	28,192	1.8%	5,244	2.7%
2025	28,625	1.5%	5,361	2.2%

1. Based on 2010 weather-normalized output of 22,764 GWh and a loss factor assumption of 7.0%.
2. The peak demands include a reduction for curtailable loads of 51 MW.
3. 2010 summer peak demand is weather-normalized actual.

Louisville Gas and Electric Company

Louisville Gas and Electric History

From 2006 to 2010, LG&E calendar sales grew at an average annual growth rate of 0.8 percent on an actual basis and -0.8 percent on a weather-normalized basis. Actual LG&E sales over this period are shown in Table 5.(3)-9. Recent growth has been most pronounced in the Residential class (3.4 percent on average since 2006) followed by the Small Commercial class (2.6 percent), Public Authorities (1.8 percent) and the Large Commercial class (0.4 percent). Sales to Industrial customers declined by 4.0% during this time. Recorded and weather-normalized sales by class are displayed in Table 5.(3)-9.

Table 5.(3)-9
LG&E Recorded and Weather-Normalized Sales by Class (GWh)

	2006	2007	2008	2009	2010
SYSTEM BILLED SALES:					
Recorded	12,010	12,669	12,058	11,333	12,277
Weather Normalized	12,132	12,210	12,121	11,562	11,712
SYSTEM USED SALES:					
Recorded	11,965	12,658	12,083	11,405	12,338
Weather Normalized	12,136	12,268	12,038	11,596	11,772
ENERGY REQUIREMENTS:					
Recorded	12,724	13,395	12,802	12,108	13,185
Weather Normalized	12,907	12,983	12,755	12,310	12,580
SALES BY CLASS:					
Residential	4,018	4,486	4,206	4,096	4,592
General Service	1,319	1,428	1,392	1,344	1,461
Large Commercial	2,295	2,409	2,331	2,273	2,332
Large Power	3,068	2,992	2,851	2,412	2,603
Public Authorities	1,205	1,282	1,241	1,221	1,296
Lighting	61	60	62	59	54
TOTAL LG&E SALES	11,965	12,658	12,083	11,405	12,338
SYSTEM LOSSES	744	751	581	524	542
Utility Use	23	24	26	29	2
ENERGY REQUIREMENTS	12,724	13,395	12,802	12,108	13,185

Louisville Gas & Electric Forecast

Like KU, LG&E's long-term economic and demographic forecast drivers are provided by Global Insight.

- *Trend Scenario:*

  The trend scenario is a projection that assumes no major economic mishaps between now and 2040. The projection is best described as depicting the mean of all possible paths the economy could follow, absent of any major disruptions such as oil price shocks or major changes in policy.

  The trend scenario between 2011 and 2040 predicts GDP growth slightly below the historical rate for the last thirty years. Personal consumption and government spending are expected to fall slightly as well in comparison to the thirty year historical trend. There is an expected improvement in business investment along with an improvement in the balance of trade with exports growing at a faster rate than imports.

- *Demographics:*

  The trend scenario provides a demographic prediction which is based on the predictions provided by the Census Bureau. Global Insight predicts slowing population growth over the next thirty years. Increased life spans for both men and women point to an aging population.

- *Output:*

  Growth in annual real U.S. Gross Domestic Product was projected to average 2.6 percent over the forecast period.

LG&E Customer Growth and Energy Sales

Table 5.(3)-10 summarizes the five- and 15-year average annual sales growth rates for each class along with their relative share of 2010 sales. Over the first five years of the energy forecast, average annual sales growth by sector is forecast to be strongest in the large commercial sector at 2.3 percent. Similarly, public authority, small commercial and residential sales are projected to grow annually at 1.8, 1.7 and 1.0 percent respectively. Over the 15-year period, sales to the large commercial sector continue to have the highest sustained growth at 2.1 percent, followed by the small commercial and public authority sectors at 1.7 percent. Industrial sales are projected to increase at an average annual rate of 0.5 percent for the 2011-2025 period.

Table 5.(3)-10

LG&E: Sales Structure and Forecast Growth Rates by Class

Class	Percent of 2010 Sales	Percent Annual Growth Rate 2011-2015	Percent Annual Growth Rate 2011-2025
Residential	37.2%	1.0%	1.4%
Small Commercial	11.8%	1.7%	1.7%
Large Commercial	18.9%	2.3%	2.1%
Industrial	21.1%	0.5%	0.5%
Public Authority	10.5%	1.8%	1.7%
Lighting	0.4%	-1.7%	-1.1%
LG&E Total	100.0%	1.3%	1.4%

LG&E's weather-normalized sales in 2010 were lower than expected due to lower than expected sales to its industrial class. The projected growth rate for sales in 2010 was 5.4 percent, versus the weather-normalized actual of 1.5 percent. Total LG&E energy sales from 2011-2015 are forecast to grow at an annual average rate of 1.3 percent. Over the 15-year forecast horizon, total sales are forecast to grow at an annual average rate of 1.4 percent. Table 5.(3)-11 summarizes LG&E's forecast of total customers and sales with their corresponding annual growth rates through 2025.

Table 5.(3)-11

LG&E: Forecast Customer Numbers and Calendar Sales (GWh)

Year	Customers	% Growth in Customers	Energy Forecast (GWh)	% Growth in Energy Sales
2010	395,868		11,772	
2011	399,238	0.9%	12,406	5.4%
2012	402,576	0.8%	12,570	1.3%
2013	406,003	0.9%	12,732	1.3%
2014	409,261	0.8%	12,884	1.2%
2015	412,747	0.9%	13,059	1.4%
2016	415,893	0.8%	13,243	1.4%
2017	419,375	0.8%	13,408	1.2%
2018	422,785	0.8%	13,601	1.4%
2019	426,327	0.8%	13,814	1.6%
2020	430,084	0.9%	14,042	1.6%
2021	433,925	0.9%	14,225	1.3%
2022	437,875	0.9%	14,434	1.5%
2023	441,658	0.9%	14,620	1.3%
2024	445,638	0.9%	14,855	1.6%
2025	449,541	0.9%	15,057	1.4%

LG&E Peak Demand

As shown in Table 5.(3)-12, LG&E's summer peak demand in 2010 (after curtailment) was 2,852 MW. On a weather-normalized basis (and after curtailment), LG&E's peak demand in 2010 was 2,733 MW.

Table 5.(3)-12

LG&E Recorded and Weather-Normalized Peak Load (MW)

	2006	**2007**	**2008**	**2009**	**2010**
SUMMER					
Actual	2,713	2,799	2,474	2,479	2,852
Normalized	2,722	2,765	2,549	2,620	2,733
	2005/2006	**2006/2007**	**2007/2008**	**2008/2009**	**2009/2010**
WINTER					
Actual	1,742	1,837	1,881	1,915	1,845
Normalized	1,806	1,868	1,897	1,835	1,828

LG&E Peak Demand Forecast

Table 5.(3)-13 contains the LG&E summer peak demand and energy requirements forecasts. The LG&E summer peak demand is forecast to increase at an average annual growth rate of 1.7 percent from 2,830 MW in 2011 to 3,596 MW in 2025, adding 765 MW over the period. Between 2011 and 2015, the summer peak demand is forecast to increase at an average annual rate of 1.3 percent from 2,830 MW to 2,980 MW, adding 150 MW over the period. For the 2015 to 2025 time period, the summer peak demand is projected to increase at an annual rate of 1.9 percent from 2,980 MW to 3,596 MW. LG&E's curtailable load is estimated to be 48 MW for each summer period during the forecast.

Table 5.(3)-13

LG&E: Forecast Energy Requirements and Peak Demand

Year	Energy Requirements, GWh[1]	Percent Growth	Summer Peak, MW [2,3]	Percent Growth
2010	12,580		2,733	
2011	13,104	4.2%	2,830	3.6%
2012	13,276	1.3%	2,857	0.9%
2013	13,451	1.3%	2,894	1.3%
2014	13,624	1.3%	2,936	1.5%
2015	13,826	1.5%	2,980	1.5%
2016	14,039	1.5%	3,007	0.9%
2017	14,218	1.3%	3,051	1.5%
2018	14,421	1.4%	3,108	1.9%
2019	14,646	1.6%	3,189	2.6%
2020	14,887	1.6%	3,264	2.4%
2021	15,081	1.3%	3,314	1.5%
2022	15,308	1.5%	3,370	1.7%
2023	15,503	1.3%	3,436	2.0%
2024	15,749	1.6%	3,527	2.6%
2025	15,965	1.4%	3,596	2.0%

1. Based on an estimate of 12,580 GWh for 2010 and a loss factor assumption of 4.4%.
2. The peak demands include a reduction for interruptible loads of 49 MW.
3. 2010 summer peak is weather-normalized actual.

5.(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, non-utility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities;

Summary of Planned Resources

The Companies' resource planning process considers the economics and practicality of available options to meet customer needs at the lowest practical cost. A study was completed to determine the optimal target reserve margin for the Companies. It is titled *LG&E and KU 2011 Reserve Margin Study* (April 2011) and is located in Volume III, Technical Appendix. This study indicates that an optimal target reserve margin in the range of 15 to 17 percent would provide an adequate and reliable system to meet customers' demand under a wide range of sensitivities to key assumptions. In the development of the optimal IRP, the Companies used a reserve margin target of 16 percent. The plan resulting from the Companies' optimal Integrated Resource Plan analysis is shown below in Table 5.(4) and is detailed in a report titled *2011 Optimal Expansion Plan Analysis* (April 2011) contained in Volume III, Technical Appendix. The in-service years for the units shown assume the Companies' base load forecast.

Table 5.(4)
Recommended 2011 Integrated Resource Plan

Year	Resource
2011	38 MW DSM Initiatives
2012	58 MW DSM Initiatives
2013	59 MW DSM Initiatives
2014	68 MW DSM Initiatives
2015	61 MW DSM Initiatives
2016	61 MW DSM Initiatives **-797 MW Coal Unit Retirements at Cane Run, Green River, and Tyrone** **907 MW 3x1 Combined Cycle Combustion Turbine**
2017	61 MW DSM Initiatives
2018	58 MW DSM Initiatives **907 MW 3x1 Combined Cycle Combustion Turbine**
2019	58 MW DSM Initiatives
2020	58 MW DSM Initiatives
2021	58 MW DSM Initiatives
2022	58 MW DSM Initiatives
2023	58 MW DSM Initiatives
2024	58 MW DSM Initiatives
2025	58 MW DSM Initiatives **907 MW 3x1 Combined Cycle Combustion Turbine**

Notes:

- DSM initiatives are incremental proposed programs including one program with annual savings that do not accumulate.
- Unit ratings for new units and retirements are summer net ratings.

The technological status, construction considerations, operating costs, and environmental features of various generation plant construction options were reviewed. After screening many technologies, the options recommended for further evaluation using the detailed resource planning computer model Strategist® included the following supply-side options:

Supercritical Pulverized Coal – Large
3x1 Combined Cycle Combustion Turbine
2x1 Combined Cycle Combustion Turbine
1x1 Combined Cycle Combustion Turbine
Wind Energy Conversion
Simple Cycle Combustion Turbine
Landfill Gas Internal Combustion Engine
Ohio Falls Hydro Expansion at Shippingport Island

Additional detail on the supply-side screening process is contained in the report titled *Analysis of Supply-Side Technology Alternatives* (March 2011) contained in Volume III, Technical Appendix.

In addition to these supply-side options, DSM programs are included in the integrated analysis. DSM plays a significant role in this IRP with both new and existing programs. At the end of 2010, the existing programs provided a potential reduction in the Companies' coincident peak demand of 182 MW. Additional programs are expected to increase this demand reduction to 500 MW by the end of 2017.

Considering the high capital costs for coal options and the anticipated retirement of six coal units at the Cane Run, Green River, and Tyrone stations due to proposed environmental regulations, the base-line IRP recommends that the next generating units added will be combined cycle combustion turbines in 2016, 2018, and 2025.

Efficiency Improvements

The plan described in Table 5.(4) does not explicitly call for generation efficiency improvements. However, the Companies continue to evaluate economic improvements to their existing generation fleet, with consideration of the environmental rules for such modifications. Maintenance schedules are coordinated across the entire generation system such that the outages will have the least economic impact to the customers and the Companies. Additional details are provided in Section 8.(2)(a).

Rehabilitation of Hydroelectric Stations

OHIO FALLS

The Companies have evaluated and will continue to evaluate the sustainable long-term generation and modernization needs and opportunities for the Ohio Falls Hydroelectric Power Station ("Ohio Falls Station"). This evaluation has considered several economic options and continues to be an ongoing process.

The Ohio Falls Station was granted a 40-year operational license by the Federal Energy Regulatory Commission ("FERC") effective November 11, 2005. The new license stipulates that the Companies complete the upgrades to the project within nine years from the effective date of the license. The rehabilitation project for the Ohio Falls Station was divided into three phases over a number of years, beginning in 2001. With the first two phases of the project complete, only the third and final phase continues. Phase 3 entails the rehabilitation of the turbine/generator units. Generally, Phase 3 of the rehabilitation takes place during the low water season in the latter six months of a given year. Rehabilitation was completed on Unit 7 in October 2006 and on Unit 6 in January 2008. Rehabilitation work on Unit 5 is scheduled to begin in 2011 and the remaining five units are planned to be completed by the end of 2014.

Rehabilitation of each unit will result in a nameplate capacity rating increase from 10 MW to 12.58 MW. However, the Ohio Falls Station is a run-of-river facility that is subject to actual river flow. Total rehabilitation of all eight units will result in increasing the expected summer net capacity output of the station to 64 MW from the 48 MW capacity output prior to performing rehabilitation.

DIX DAM

KU has also undertaken a project to overhaul the three units at the Dix Dam Station. This project involves rewinding the generators, refurbishing the turbine sections, and upgrading controls. Each overhaul will result in a capacity increase on each unit from 8 to 10 MW, for a total increase of 6 MW, at the current lake level target range. The overhaul on Unit 3 was completed in 2009 with final testing completed in February 2010. Unit 2 is expected to be completed in 2011 and Unit 1 is expected to be completed in 2012.

In addition to the rehabilitation efforts at the Ohio Falls and Dix Dam Stations, the Companies continue to monitor potential hydro opportunities. However, sites for additional conventional hydro facilities on the Ohio River are limited.

Demand Side Programs

The Companies received approval for their current portfolio of energy efficiency programs from the Kentucky Public Service Commission ("KPSC") on March 31, 2008, in Case No. 2007-00319. The Companies requested, and the KPSC approved, a seven-year plan for the programs in light of the significant investment in time and resources required to initiate operations, obtain participants, and achieve the projected demand and energy savings. The three years since the approval of these programs has granted greater insight into the challenges and obstacles associated with the outlined metrics within that program plan. As a result of the lessons learned, the Companies filed with the KPSC in Case No. 2011-00134 their Demand Side Management/Energy Efficiency ("DSM/EE") Program Plan to enhance the following programs: Residential and Commercial Load Management; Commercial Conservation; Residential Conservation; Residential Low Income Weatherization Program; and Program Development and Administration.

In addition to enhancing several currently approved programs, the Companies plan to seek approval for additional DSM programs that will further increase energy and demand savings for the Companies. These programs include the Smart Energy Profile Program, Residential Incentives Program, and a Residential Refrigerator Removal Program. Upon approval of proposed program enhancements and new programming, the Companies DSM/EE portfolio of programs will operate through December 31, 2017 and allow the Companies to achieve 500 MW of coincident peak demand reduction by the end of 2017.

Moreover, the following programs were approved by the KPSC in Case No. 2007-00319 and will remain unchanged: Residential High Efficiency Lighting, Residential New Construction, Residential and Commercial HVAC Diagnostic and Tune Up. These programs were not included in the plan filed in Case No. 2011-00134. The Companies propose to continue these existing programs through 2014 as these programs are categorized as "market transformation programs" or are currently operating satisfactorily within the approved program designs, and therefore do not warrant enhancements at this time.

Non-Utility Sources of Generation

New Long Term Power Purchases

The Companies have used a Request for Proposals ("RFP") process to obtain offers from the electric market for specific power needs. The Companies distribute its RFP to qualified parties in the market ensuring broad market coverage and the opportunity to discover least cost options for power supply. This process serves the Companies and the native load well.

On December 1, 2010, the Companies issued an RFP for firm generating capacity and energy in order to evaluate alternatives for meeting existing and pending EPA regulations and to meet future load growth. Eighteen parties responded with offers to this RFP and the Companies are currently evaluating the various proposals. While this IRP outlines a least cost expansion plan, the evaluation of the current RFP responses will ultimately determine the least cost resources proposed to meet the Companies' next generation need.

Short-Term Power Purchases

The Companies consider wholesale market opportunities to serve native load on a short term non-firm basis only. These short term purchases are typically made as economy purchases to avoid running higher cost resources. From 2008 through 2010, changing market conditions led to variation in the quantity and prices paid for wholesale power purchases. 2008 covered the height of the economic boom before the downturn in August of 2008. Native load was lower than planned, requiring fewer outside resources than expected. The realized average wholesale power price of $79/Megawatt-hour (MWh) was 36 percent higher than budget which also contributed to the volume of purchases of 516 Gigawatt-hours (GWh) being 10 percent below budget. In 2009, the brunt of the recession led to further reductions in native load. While realized prices averaging $42/MWh were 45 percent below budget, only 449 GWh were purchased, 49 percent fewer than budgeted. The economic rebound in 2010 led to native load 8 percent over budget, which led to purchases of 640 GWh, 49 percent more than expected. The realized average market price average of $48/MWh was slightly lower than expected.

New Power Plants

New power plants are major components of the 15-year least-cost plan. The plan described in Table 5.(4) calls for three 3x1 combined cycle combustion turbines as new generation sources in the fifteen year window. This expansion plan is based on the current assumptions used in the supporting analyses and is subject to change. The Companies will continue to evaluate the available options to meet capacity needs in a least cost manner and will request approvals for capacity additions through normal regulatory processes.

Transmission Improvements

The Companies routinely identify transmission construction projects and upgrades required for maintaining the adequacy of its transmission system to meet projected customer demands. The construction projects currently identified are included in Volume III, Technical Appendix under the section labeled *Transmission Information.*

Bulk Power Purchases and Sales and Interchange

The Companies each have purchase power arrangements with OVEC to provide additional sources of capacity. OVEC was originally formed for the purpose of providing electric power requirements projected for the uranium enrichment complex being built near Portsmouth, Ohio. In 1993, the United States Enrichment Corporation was formed to lease the uranium enrichment facilities from the United States Department of Energy ("DOE") and assume the responsibility for uranium enrichment services for the U.S. The DOE gave notice of reductions in its contract demand for electricity, with power and energy no longer requested after Aug. 31, 2001. The power and energy thus released from the plants became available to the sponsoring companies under the Inter-Company Power Agreement ("ICPA"). OVEC's Kyger Creek Plant at Cheshire, Ohio, and Indiana-Kentucky Electric Corporation's Clifty Creek Plant at Madison, Indiana have generating capacities of 1,075 MW and 1,290 MW, respectively.

The eight sponsors of OVEC entered the ICPA at the formation of OVEC. Under the ICPA, each sponsoring company undertook certain obligations, including the contractual obligation to make up power shortages to the Portsmouth facility, and had the contractual right to "surplus" OVEC power, all in accordance with each sponsor's Power Participation Ratio. The original ICPA expired March 12, 2006.

Beginning in April 2006, LG&E's portion of the power participation benefits became 5.63 percent pursuant to the Amended and Restated ICPA dated as of March 13, 2006, filed with and approved by the KPSC in Case No. 2004-00396. KU retained its 2.5 percent ownership. During the 2011 summer peak, the Companies plan to receive 155 MW net and varying capacity during the remaining months due to unit maintenance schedules on the OVEC system. The owners of OVEC have approved an extension of the ICPA to 2040 in order to improve the financing of existing debt associated with environmental compliance equipment at both Kyger and Clifty Creek plants. An application was filed with the KPSC in March 2011 regarding this extension.

5.(5) Steps to be taken during the next three years to implement the plan;

As part of implementing this plan during the next three years, the Companies will closely monitor the development of environmental regulations and will undertake all studies and other long lead activities necessary to make decisions regarding existing and future generating resources. Additionally, the DSM measures outlined below will be taken.

Demand-Side Management

Upon approval of the DSM/EE expansion filing in Case No. 2011-00134, the Companies will implement all approved enhanced and new programs as quickly and reasonably possible. All new programs and enhancements to existing programs will utilize a "phased approach" to implementation to allow for optimum program execution and program adjustment, leading to high-quality service delivery with full program deployment by the second year of operation.

As the programs are implemented, the Companies will perform ongoing impact evaluation focusing on quantifying the energy and demand savings and other economic benefits of the enhanced, new and existing/unchanged programs in the DSM/EE portfolio. In addition, the Companies will continue to review and evaluate the existing and potential new DSM programs for future expansion filings.

5.(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.

Environmental Regulations Uncertainty

A key uncertainty in defining the resource plan is the impact of impending environmental regulations. In the last few years, the EPA has proposed a number of regulations, some of which are still in the proposal phase while others are expected to take effect in the near future. These regulations are discussed in detail in Section 8.(5)(b) and 8.(5)(f). The base assumption for this plan is that the most significant impacts to the Companies' generating fleet will occur in 2016 when the most stringent regulations are anticipated to commence. As demonstrated in the report titled *2011 Optimal Expansion Plan Analysis* (April 2011) contained in Volume III, Technical Appendix, the least cost plan that complies with these regulations includes retiring the six coal units at the Cane Run, Green River, and Tyrone Stations in 2016.

Forecast Uncertainty

The econometric modeling approach as utilized in the latest energy forecasts seeks to define the historical statistical relationships between the dependent variable (electricity consumption) and the various independent variables that influence the behavior of the dependent variable. These relationships are assumed to continue in the future and are used to develop the forecasts. The Company updates its energy sales, peak demand and customer forecasts on an annual basis to ensure that the structural relationships between explanatory and dependent variables are fully current. To address uncertainty, the Companies developed high and low scenarios to support sensitivity analysis of the various resource acquisition plans being studied. For the 2011 IRP, these scenarios were based on probabilistic simulation of the historical volatility exhibited by each utility's weather-normalized year-over-year sales trend. These alternative outlooks for Combined Company energy requirements and demand are presented in Tables 5.(6)-1 and 5.(6)-2.

Table 5.(6)-1

Combined Company Base IRP, High, and Low

Energy Requirements Forecasts (GWh)

Year	Base Energy Requirements	High Energy Requirements	Low Energy Requirements
2011	36,019	37,329	34,708
2012	36,657	38,013	35,301
2013	37,271	38,652	35,890
2014	37,797	39,201	36,392
2015	38,451	39,875	37,027
2016	39,050	40,500	37,599
2017	39,557	41,030	38,084
2018	40,129	41,621	38,637
2019	40,773	42,287	39,259
2020	41,436	42,974	39,898
2021	41,987	43,551	40,424
2022	42,630	44,214	41,046
2023	43,209	44,818	41,600
2024	43,941	45,571	42,311
2025	44,590	46,248	42,931

Table 5.(6)-2

Combined Company Base IRP, High, and Low

Peak Demand Forecasts (MW)

Year	Base Peak	High Peak	Low Peak
2011	6,976	7,231	6,722
2012	7,094	7,356	6,831
2013	7,235	7,500	6,970
2014	7,354	7,624	7,083
2015	7,477	7,751	7,203
2016	7,529	7,805	7,252
2017	7,634	7,915	7,353
2018	7,771	8,056	7,486
2019	7,968	8,259	7,678
2020	8,159	8,455	7,863
2021	8,266	8,566	7,967
2022	8,392	8,694	8,089
2023	8,545	8,852	8,238
2024	8,771	9,084	8,458
2025	8,957	9,277	8,638
2026	8,278	8,602	7,953

Short Term Power Purchases

Over time, the failure to add sufficient new generation capacity could impact both the price and availability of power from the energy market. The availability of electric transmission capability into the Companies' system will also impact price volatility and the availability of power. The forward market will provide information as to the expected relationship between supply, demand, and deliverability. Changes in future market prices may initiate a corresponding revision to the plan as presented in this resource assessment.

DSM Implementation

Due to the voluntary nature of the DSM/EE programs offered by the Companies, the amount of customer participation directly impacts the energy and demand reduction of the designed programs. As this is recognized by the Companies, the enhanced and new programming in the DSM/EE filing in Case No. 2011-00134 looks to address this issue by including modification of financial incentives and customized rebates for programming that provide the most energy and demand savings for the Companies.

Aging Units

The generating units in the Companies' fleet continue to age. The four oldest steam generating units in the system are Green River Units 3 and 4, Tyrone Unit 3, and Brown Unit 1. Each of these is over 50 years old, which is beyond the typical design life for a coal-fired unit. Some of the oldest combustion turbines are the LG&E smaller-sized combustion turbines and the KU Haefling combustion turbines ("CTs"). Each of these units is over 30 years of age, which is considered the typical full life expectancy for small frame combustion turbines. Table 5.(6)-4 indicates the age of the older units.

Table 5.(6)-4
Aging Units

Fuel	Plant Name	Unit	Summer Capacity	In Service Year	Age (2011)
Coal	Tyrone	3	71	1953	58
Coal	Green River	3	68	1954	57
Coal	Brown	1	101	1957	54
Coal	Green River	4	95	1959	52
Gas	Cane Run	11	14	1968	43
Gas	Paddy's Run	11	12	1968	43
Gas	Paddy's Run	12	23	1968	43
Gas	Zorn	1	14	1969	42
Gas	Haefling	1,2,3	36	1970	41

High-level condition and performance assessments have been periodically performed on the generating units in the Companies' fleet. The most recent assessment concluded that the majority of the coal-fired units are capable of operating for at least fifteen more years with standard maintenance but that the older units will require additional investment to maintain continued operation. Further, the remaining useful life of the oldest units could be impacted by more stringent environmental regulations. These assessments also concluded that the CTs at both the E.W. Brown and Trimble County Stations are capable of continued safe and reliable operation for at least another fifteen years and that the remaining useful life of the older CTs at the Cane Run and Paddy's Run Stations can be extended another fifteen years with increased maintenance expenditures.

The economics surrounding the continued operation of the Companies' older units will continue to be reviewed periodically to ensure the efficiency of the overall system. The relatively high production costs of older units and further environmental restrictions only worsen their relative economics. It could become economic to retire many of these units even without a significant mechanical failure. Six coal unit retirements totaling 797 MW are assumed in the base resource plan due to the proposal of more stringent environmental regulations to take effect in the fifteen year window. The analysis leading to this assumption is discussed in more detail in the report titled *2011 Optimal Expansion Plan Analysis* (April 2011) located in Volume III, Technical Appendix.

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6. SIGNIFICANT CHANGES

All integrated resource plans shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate changes.

The plan most recently filed is the 2008 Joint IRP of LG&E and KU. Several significant changes have taken place since that filing, as reviewed in this section. The major changes in the 2011 IRP from the 2008 plan are described in the sections that follow.

RESOURCE ASSESSMENT

The resource assessment plan is consistent with overall good business planning and outlines a strategy that furnishes electric energy services over the planning horizon in the most economic, efficient, and reliable manner while considering environmental factors. The 2008 plan recommended the Trimble County Unit 2 supercritical coal unit, two 2x1 combined cycle combustion turbines (one in 2015 and one in 2019), one simple cycle combustion turbine in 2022, and a cumulative total of 441 MW of new DSM initiatives.

Since the 2008 IRP, the Companies have continued to grow the Energy Efficiency programs. Demand savings achieved through 2010 was 182 MW. Construction of Trimble County Unit 2 was completed with a commercial operation date of January 22, 2011. The Companies' continuous resource planning process includes monitoring the latest trends in construction costs and commodity prices, and in most recent evaluations, a 3x1 combined cycle gas unit has been identified in the least-cost expansion plan as the next generating unit to be constructed in 2016 followed by two additional 3x1 combined cycle units in 2018 and 2025.

This plan also considers the potential retirement of the coal units at the Cane Run, Green River, and Tyrone Stations due to proposed environmental regulations that are expected to make the continued operation of these units economically unjustifiable.

OMU

The Contract (the "Contract"), dated September 30, 1960, among KU, the City of Owensboro (the "City"), and the Owensboro City Utility Commission (the "City Commission") (collectively, the City and the City Commission are hereinafter referred to as "OMU") ended in May 2010 after litigation that began in 2006 in U.S. District Court. On February 19, 2009 the U.S. District Court for the Western District of Kentucky entered a final judgment in the OMU litigation, following the bench trial that occurred in 2008. The Court entered a monetary judgment in KU's favor, reflecting amounts due from OMU for back-up power invoices that had not been paid and as refunds for overcharges billed to KU for allowances for nitrogen oxides ("NO_x") emissions. The Court, however, did not award KU any damages on its counterclaim that OMU had breached the contract by failing to operate and maintain its units in a good and workmanlike manner.

On March 5, 2009 OMU filed a motion to alter, amend or vacate the portion of the February 19 ruling which awarded interest to KU. That same day, KU filed a motion to correct a wording error in the opinion relating to NO_x issues. On May 11, 2009, the parties to the litigation entered into a settlement agreement, resolving all remaining issues and eliminating any further challenges to the Court's rulings in the litigation. As a result, KU's contract with OMU ended on May 16, 2010 at 11:59:59 p.m. EST.

LOAD FORECAST

The following discussion presents the changes in the energy and demand forecasts for the Combined Companies, and for KU and LG&E.

Summary of Forecast Changes

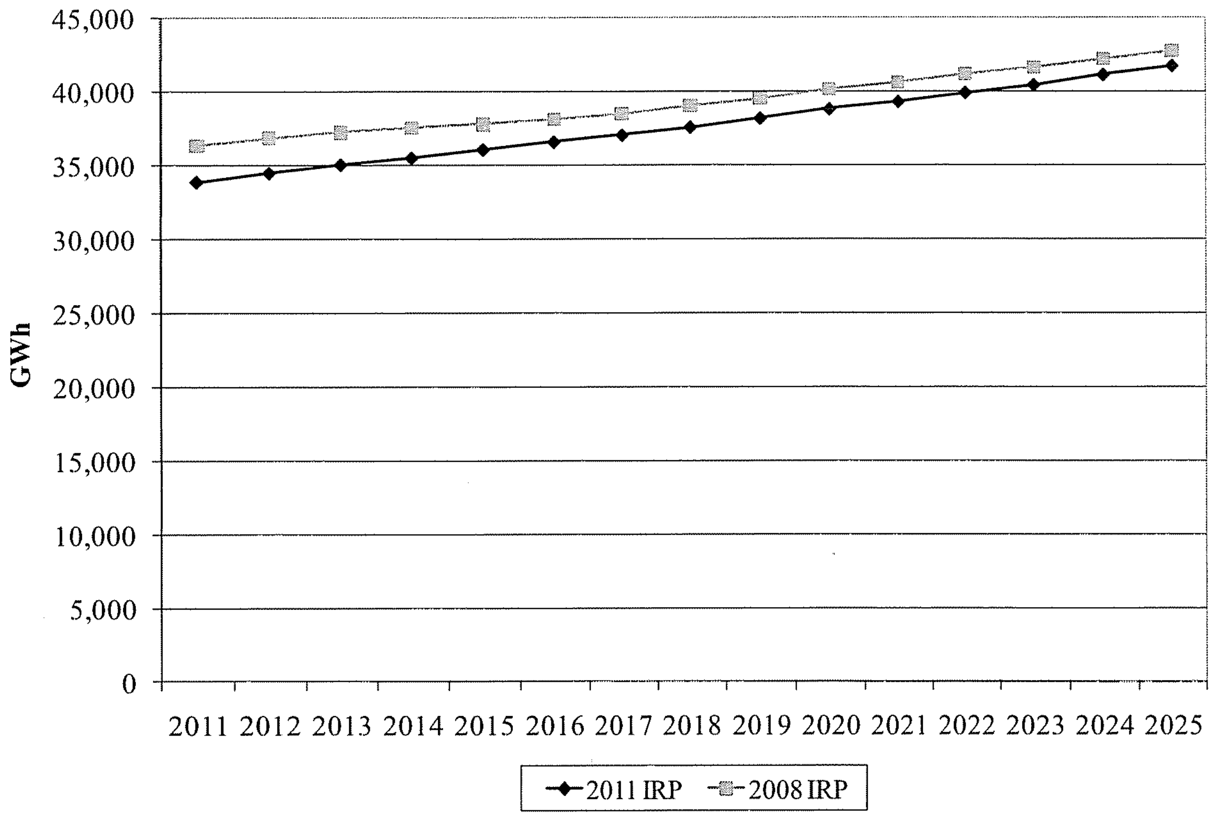
Combined Company

Compared to the 2008 IRP, the current Combined Companies' sales forecast for the 2011-2015 period has been reduced by an average of 2,153 GWh per year (5.8 percent). However, as the economy continues to recover from the recent recession, the anticipated growth in sales during this period is higher (1.6 percent versus 1.0 percent). Through the latter part of the planning period, the difference between the sales forecasts narrows. By 2025, sales are projected to be 2.3 percent below the 2008 IRP level for 2025. The change in sales for each year is shown in Table 6.(1)-1 and in Graph 6.(1)-1. In the 2011 IRP forecast, the downward revisions are driven primarily by the economic downturn, including a slow economic recovery in large commercial/industrial sales and residential use-per-customer. Mandated energy efficiency is also increasing. The most notable change since the 2008 IRP is related to further energy efficiency specified by the ARRA which contains additional energy efficiency mandates for building weatherization and appliance efficiency beyond the EISA 2007.

Table 6.(1)-1
Comparison of Combined Companies' 2011 and 2008 IRP Calendar Sales Forecasts

Year	2011 IRP (GWh)	2008 IRP (GWh)	Change (GWh)	% Change
2011	33,912	36,373	-2,462	-6.8%
2012	34,511	36,873	-2,363	-6.4%
2013	35,076	37,268	-2,191	-5.9%
2014	35,530	37,566	-2,036	-5.4%
2015	36,097	37,809	-1,712	-4.5%
2016	36,615	38,112	-1,497	-3.9%
2017	37,074	38,509	-1,435	-3.7%
2018	37,611	39,038	-1,427	-3.7%
2019	38,219	39,545	-1,326	-3.4%
2020	38,835	40,148	-1,313	-3.3%
2021	39,342	40,649	-1,307	-3.2%
2022	39,940	41,199	-1,259	-3.1%
2023	40,477	41,687	-1,210	-2.9%
2024	41,172	42,231	-1,059	-2.5%
2025	41,775	42,775	-1,001	-2.3%
2011-2015 AVG	1.6%	1.0%	-2,153	-5.8%
2011-2025 AVG	1.5%	1.2%	-1,573	-4.1%

Graph 6.(1)-1
Combined Company Calendar Sales - 2011 vs. 2008 IRP Forecasts (GWh)

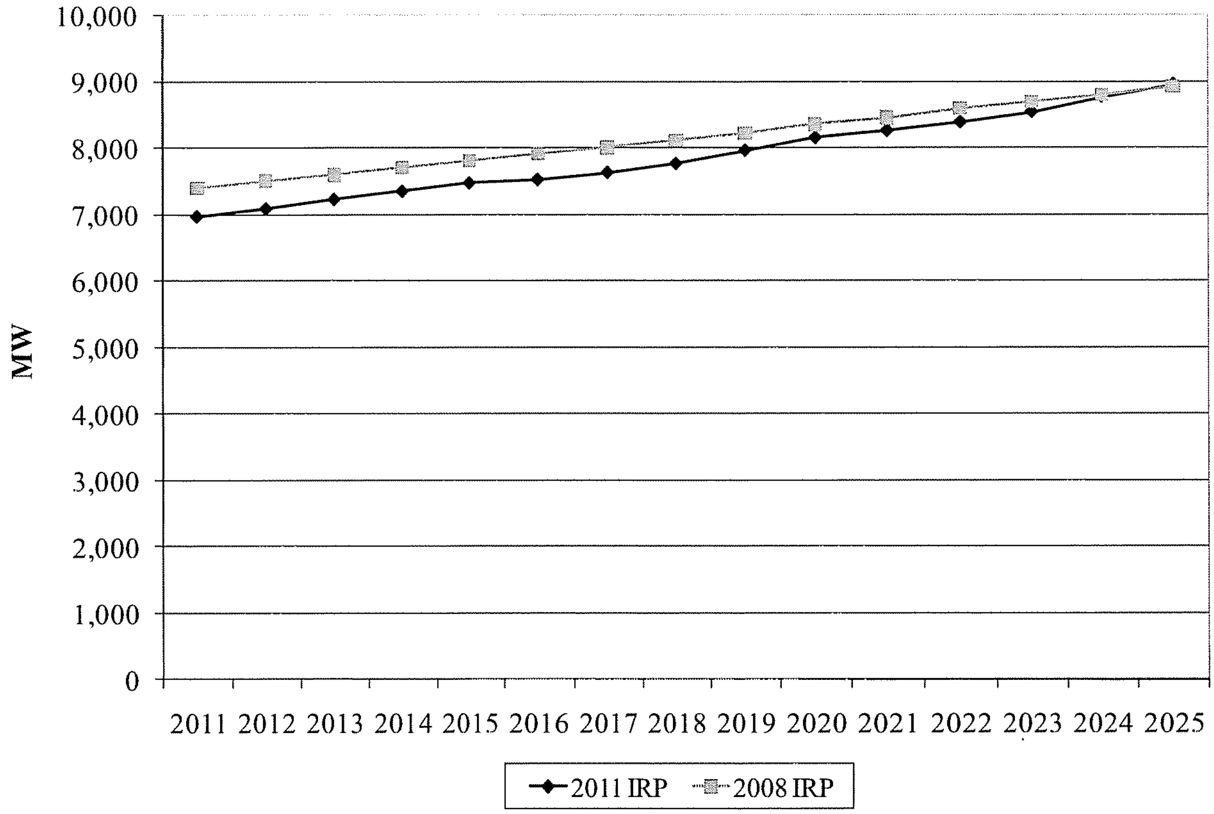


Compared to the 2008 IRP, the current Combined Companies' peak demand forecast for the 2011-2015 period has been reduced by an average of 380 MW (5.0 percent) per year. However, the anticipated growth in peak demand during this period is higher at 1.7 percent versus 1.3 percent. By 2025, peak demand is expected to approximately equal the 2008 IRP's forecast. The change in peak demand for each year is shown in Table 6.(1)-2 and in Graph 6.(1)-2. Similar to energy sales, the downward revisions in the current peak demand forecast are driven primarily by slower growth in large commercial/industrial sales and residential use-per-customer. Reflecting recovery from the recent recession, peak demand and sales in the 2011 IRP grows at a faster rate than the 2008 IRP.

Table 6.(1)-2
Comparison of Combined Companies' 2011 and 2008 IRP Peak Demand Forecasts

Year	2011 IRP (MW)	2008 IRP (MW)	Change (MW)	% Change
2011	6,976	7,404	-427	-5.8%
2012	7,094	7,512	-418	-5.6%
2013	7,235	7,600	-365	-4.8%
2014	7,354	7,707	-353	-4.6%
2015	7,477	7,812	-334	-4.3%
2016	7,529	7,912	-383	-4.8%
2017	7,634	8,012	-378	-4.7%
2018	7,771	8,127	-355	-4.4%
2019	7,968	8,226	-257	-3.1%
2020	8,159	8,364	-205	-2.4%
2021	8,266	8,461	-195	-2.3%
2022	8,392	8,591	-200	-2.3%
2023	8,545	8,698	-153	-1.8%
2024	8,771	8,804	-33	-0.4%
2025	8,957	8,933	24	0.3%
2011-2015 AVG	1.7%	1.3%	-380	-5.0%
2011-2025 AVG	1.8%	1.4%	-269	-3.4%

Graph 6.(1)-2
Combined Companies' Peak Demand – 2011 vs. 2008 IRP Forecasts (MW)



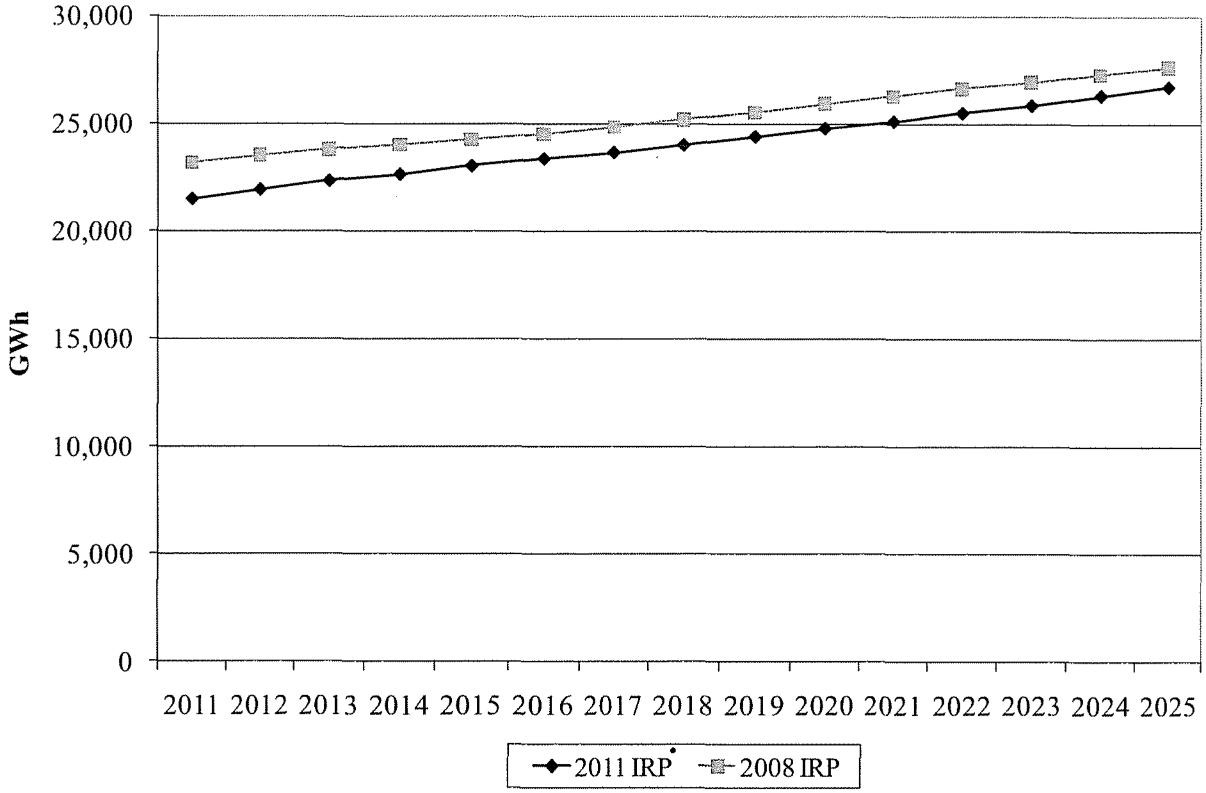
Kentucky Utilities Company

Compared to the 2008 IRP, the current KU sales forecast for the 2011-2015 period has been reduced by an average of 1,473 GWh per year (6.2 percent). The anticipated growth in sales during this period has remained steady at 1.5 percent. The downward shift in sales projections is driven primarily by the 2008-2009 economic downturn. The change in KU sales for each year is shown in Table 6.(1)-3 and in Graph 6.(1)-3. In the 2011 IRP, the downward revisions in the latter part of the forecast period are driven primarily by slower growth in large commercial/industrial sales and residential use-per-customer.

Table 6.(1)-3
Comparison of KU's 2011 and 2008 IRP Calendar Sales Forecasts

Year	2011 IRP (GWh)	2008 IRP (GWh)	Change (GWh)	% Change
2011	21,506	23,212	-1,706	-7.3%
2012	21,940	23,540	-1,600	-6.8%
2013	22,344	23,796	-1,452	-6.1%
2014	22,646	24,019	-1,373	-5.7%
2015	23,039	24,273	-1,235	-5.1%
2016	23,372	24,534	-1,161	-4.7%
2017	23,667	24,821	-1,154	-4.7%
2018	24,010	25,185	-1,176	-4.7%
2019	24,405	25,526	-1,122	-4.4%
2020	24,793	25,941	-1,148	-4.4%
2021	25,116	26,275	-1,158	-4.4%
2022	25,506	26,646	-1,140	-4.3%
2023	25,858	26,948	-1,090	-4.0%
2024	26,317	27,291	-974	-3.6%
2025	26,718	27,650	-932	-3.4%
2011-2015 AVG	1.7%	1.1%	-1,473	-6.2%
2011-2025 AVG	1.6%	1.3%	-1,228	-4.9%

Graph 6.(1)-3
KU 2011 vs. 2008 IRP Calendar Sales Forecast Comparison (GWh)

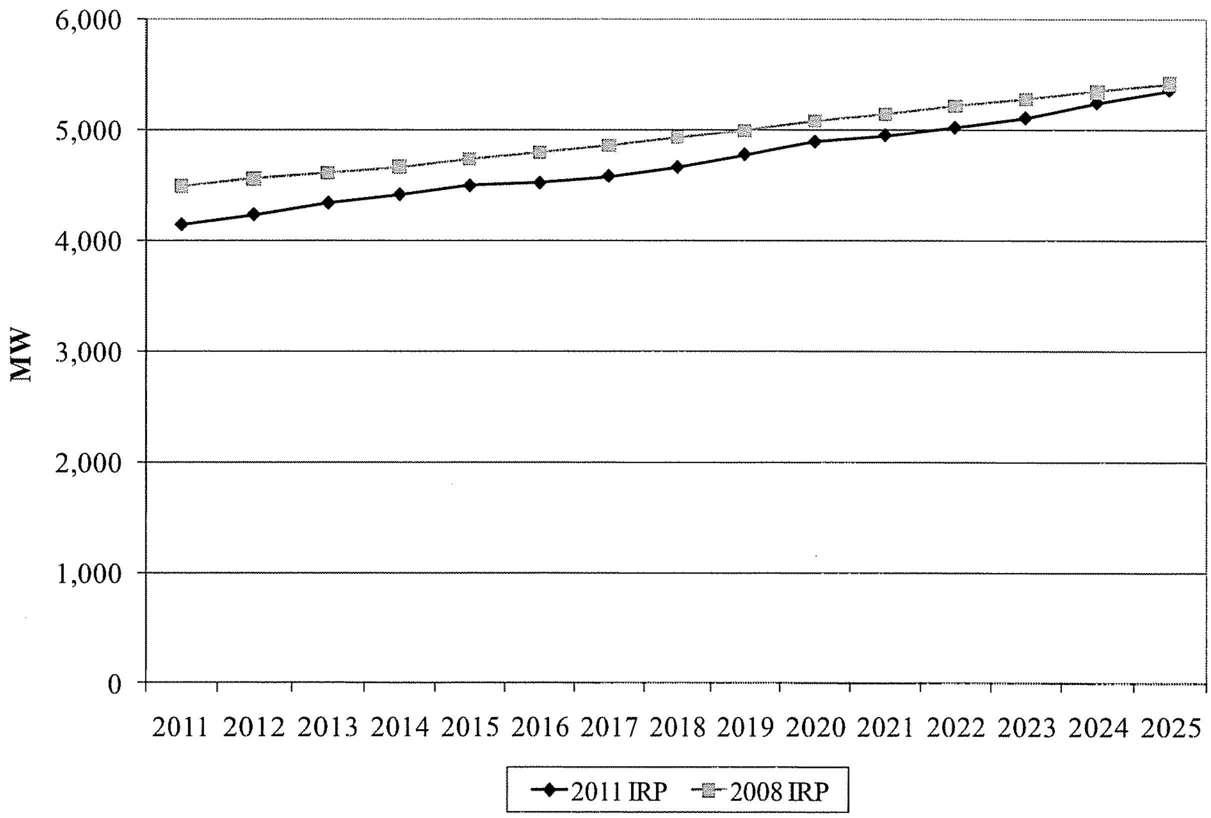


Compared to the 2008 IRP, the current KU peak demand forecast for the 2011-2015 period has decreased by an average of 287 MW (6.2 percent) per year. The anticipated growth in peak demand during this period has increased slightly, from 1.3 percent to 2.1 percent. Through 2025, the current KU peak demand averages 227 MW less than the peak demand in the 2008 IRP due primarily to a permanent lag in peak demand caused by the 2008-2009 economic downturn. The change in peak demand for each year is shown in Table 6.(1)-4 and in Graph 6.(1)-4.

Table 6.(1)-4
Comparison of KU's 2011 and 2008 IRP Peak Demand Forecasts

Year	2011 IRP (MW)	2008 IRP (MW)	Change (MW)	% Change
2011	4,146	4,496	-350	-7.8%
2012	4,237	4,560	-323	-7.1%
2013	4,341	4,615	-273	-5.9%
2014	4,417	4,669	-252	-5.4%
2015	4,497	4,736	-239	-5.0%
2016	4,522	4,799	-277	-5.8%
2017	4,584	4,861	-277	-5.7%
2018	4,663	4,933	-270	-5.5%
2019	4,780	5,001	-221	-4.4%
2020	4,895	5,082	-187	-3.7%
2021	4,953	5,149	-196	-3.8%
2022	5,022	5,223	-202	-3.9%
2023	5,109	5,284	-175	-3.3%
2024	5,244	5,352	-108	-2.0%
2025	5,361	5,424	-62	-1.1%
2011-2015 AVG	2.1%	1.3%	-287	-6.2%
2011-2025 AVG	1.9%	1.3%	-227	-4.7%

Graph 6.(1)-4
KU 2011 vs. 2008 IRP Peak Demand Forecast Comparison (MW)



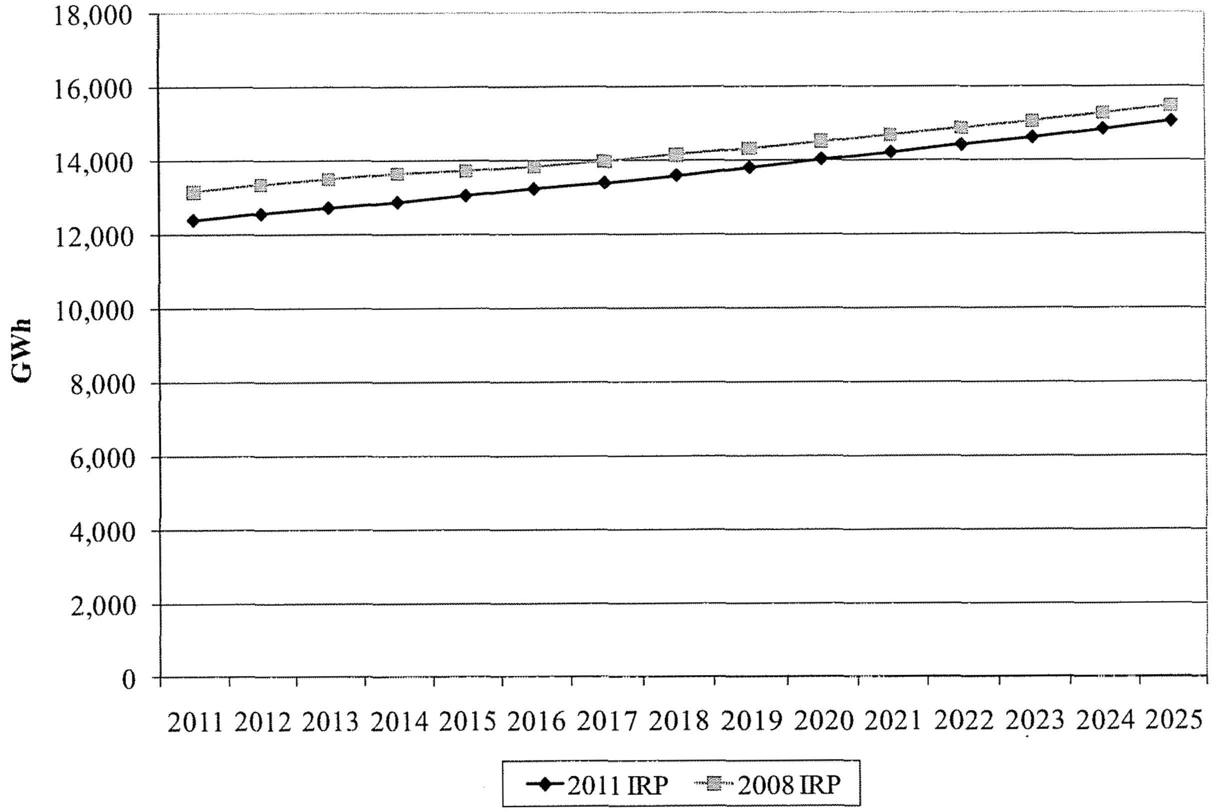
Louisville Gas and Electric Company

Compared to the 2008 IRP, the current LG&E sales forecast for the 2011-2015 period has been reduced by an average of 756 GWh per year (5.6 percent). The anticipated growth in sales during this period is slightly higher at 1.3 percent versus 1.1 percent. The change in LG&E sales for each year is shown in Table 6.(1)-5 and in Graph 6.(1)-5. In the 2011 IRP, the downward revisions to the forecast are driven primarily by the economic downturn including slower growth in large commercial/industrial sales and residential use-per-customer. Compared to the KU service territory, the lower growth in sales in the LG&E service territory (1.4 percent over the 2011-2025 period for LG&E versus 1.9 percent for KU) is driven by lower growth in sales to LG&E's large commercial/industrial customers.

Table 6.(1)-5
Comparison of LG&E's 2011 and 2008 IRP Calendar Sales Forecasts

Year	2011 IRP (GWh)	2008 IRP (GWh)	Change (GWh)	% Change
2011	12,406	13,162	-756	-5.7%
2012	12,570	13,350	-779	-5.8%
2013	12,732	13,519	-787	-5.8%
2014	12,884	13,657	-774	-5.7%
2015	13,059	13,741	-683	-5.0%
2016	13,243	13,847	-604	-4.4%
2017	13,408	13,989	-581	-4.2%
2018	13,601	14,163	-562	-4.0%
2019	13,814	14,336	-522	-3.6%
2020	14,042	14,528	-487	-3.3%
2021	14,225	14,700	-475	-3.2%
2022	14,434	14,883	-450	-3.0%
2023	14,620	15,074	-454	-3.0%
2024	14,855	15,280	-424	-2.8%
2025	15,057	15,469	-412	-2.7%
2011-2015 AVG	1.3%	1.1%	-756	-5.6%
2011-2025 AVG	1.4%	1.2%	-583	-4.1%

Graph 6.(1)-5
LG&E 2011 vs. 2008 IRP Calendar Sales Forecast Comparison (GWh)

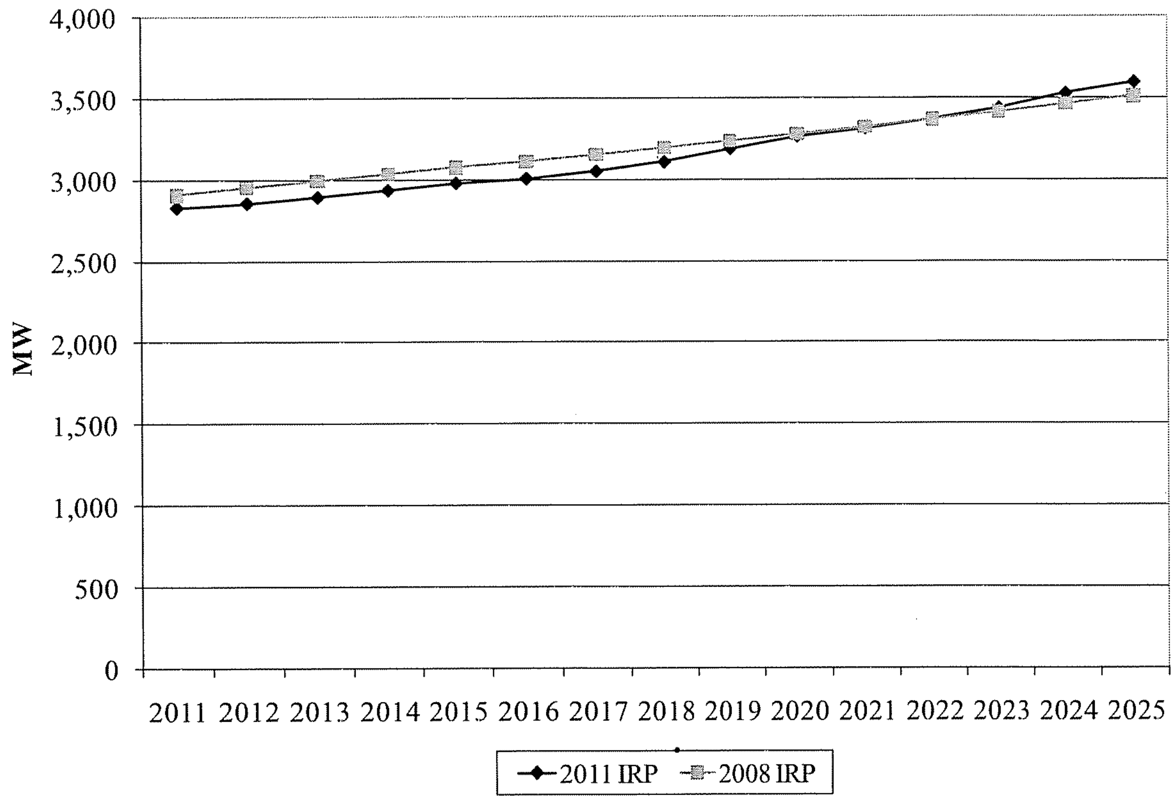


Compared to the 2008 IRP, the current LG&E peak demand forecast for the 2011-2015 period has decreased by an average of 94 MW (3.1 percent) per year. The anticipated growth in peak demand during this period is also lower (1.3 percent versus 1.4 percent) compared to the 2008 IRP. Through 2025, the current LG&E peak demand forecast has decreased by an average of 44 MW (1.5 percent) per year due primarily to the 2008-2009 economic downturn. The change in peak demand for each year is shown in Table 6.(1)-6 and in Graph 6.(1)-6.

Table 6.(1)-6
Comparison of LG&E's 2011 and 2008 IRP Peak Demand Forecasts

Year	2011 IRP (MW)	2008 IRP (MW)	Change (MW)	% Change
2011	2,830	2,908	-78	-2.7%
2012	2,857	2,952	-96	-3.2%
2013	2,894	2,995	-102	-3.4%
2014	2,936	3,038	-101	-3.3%
2015	2,980	3,075	-95	-3.1%
2016	3,007	3,113	-106	-3.4%
2017	3,051	3,152	-101	-3.2%
2018	3,108	3,194	-86	-2.7%
2019	3,189	3,236	-47	-1.5%
2020	3,264	3,282	-17	-0.5%
2021	3,314	3,324	-10	-0.3%
2022	3,370	3,368	2	0.1%
2023	3,436	3,414	22	0.6%
2024	3,527	3,464	63	1.8%
2025	3,596	3,510	86	2.4%
2011-2015 AVG	1.3%	1.4%	-94	-3.1%
2011-2025 AVG	1.7%	1.4%	-44	-1.5%

Graph 6.(1)-6
LG&E 2011 vs. 2008 IRP Peak Demand Forecast Comparison (MW)



Reason for Forecast Changes

The energy and demand forecasts in the 2011 IRP reflect the following changes from the previous filing:

- incorporation of more recent sales trends in the forecasting models
- incorporation of the impacts of American Recovery and Reinvestment Act of 2009 through the statistically-adjusted end-use ("SAE") forecasting model
- incorporation of a new SAE forecasting model for the commercial class
- changes in the curtailable/interruptible loads and efficiency programs
- incorporation of more recent weather data in the calculation of 'normal' weather
- updates to the economic and demographic assumptions
- updates in the methodologies used to prepare forecasts

Recent Sales Trends

Combined Company

On a Combined Company basis, weather-normalized calendar sales were below forecasted levels between 2008 and 2010 (see Table 6.(1)-7). The differences between the 2008 and 2011 IRP forecasts reflect the impact of the 2008-2009 recession as well as future expectations.

Table 6.(1)-7
Combined Company Calendar Sales (GWh)
Variance to 2008 IRP Forecast

Year	2008 IRP	W/N Actuals	Difference	% Difference
2008	34,775	33,117	-1,658	-4.8%
2009	35,311	31,993	-3,317	-9.4%
2010	35,798	33,006	-2,793	-7.8%

Kentucky Utilities Company

KU's weather-normalized calendar sales fell short of forecasted levels between 2008 and 2010 (see Table 6.(1)-8). The differences between the 2008 and 2011 IRP forecasts reflect the impact of the 2008-2009 recession as well as future expectations.

Table 6.(1)-8
Kentucky Utilities Company Calendar Sales (GWh)
Variance to 2008 IRP Forecast

Year	2008 IRP	W/N Actuals	Difference	% Difference
2008	22,160	21,079	-1,081	-4.9%
2009	22,513	20,398	-2,115	-9.4%
2010	22,843	21,234	-1,608	-7.0%

Louisville Gas and Electric Company

LG&E's weather-normalized calendar sales were also below forecasted levels between 2008 and 2010 (see Table 6.(1)-9). The differences between the 2008 and 2011 IRP forecasts reflect the impact of the 2008-2009 recession as well as future expectations.

Table 6.(1)-9
Louisville Gas and Electric Company Calendar Sales (GWh)
Variance to 2008 IRP Forecast

Year	2008 IRP	W/N Actuals	Difference	% Difference
2008	12,615	12,038	-577	-4.6%
2009	12,797	11,596	-1,202	-9.4%
2010	12,956	11,772	-1,184	-9.1%

Energy Independence and Security Act of 2007 and American Recovery and Reinvestment Act of 2009

EISA 2007 was signed into law by President Bush in December 2007. The provisions in EISA 2007 are primarily designed to increase energy efficiency and the availability of renewable energy. LG&E and KU energy sales will be impacted by provisions in the act that tighten lighting and appliance efficiency standards as well as foster the development of new building and commercial equipment standards. EISA 2007 efficiencies have been embedded into the Companies' models to construct the small commercial and residential forecasts.

The ARRA was introduced by President Obama in February 2009. The provisions in the ARRA relative to energy are intended to increase energy efficiency, research and development of renewable energy and alternative fuels, and research and development of new technology such as smart grid infrastructure. LG&E and KU electricity sales will be impacted primarily by provisions in the act that make efforts to weatherize residential, commercial, and government buildings. The 2011 IRP incorporates the impact of the new weatherization incentives which come in the form of tax cuts, funding, loans, and block grants

Changes in Curtailable/Interruptible Loads

The historical record of energy sales and peak demand – the basis on which forward projections are developed – incorporates the effects of curtailment and interruption of supply by the Companies in accordance with the terms of existing curtailable contracts. Thus, the projections of sales and peak demand include a component of 'embedded' load curtailment. Changes in the amount of curtailable demand can impact the level of the overall demand forecast. The changes in the amount of curtailable demand from the 2008 IRP to the 2011 IRP are summarized below in Table 6.(1)-10.

Table 6.(1)-10

Total Curtailable/Interruptible Load Provision (MW)

Forecast	KU	LG&E	Combined
2008 IRP	50	55	105
2011 IRP	66	48	114
Change	16	(7)	9

Updates to Weather Assumptions

For both KU and LG&E, the most recent 20-year average of heating degree days ("HDDs") and cooling degree days ("CDDs") is used to represent the weather conditions that are likely to be experienced on average over the forecast horizon. "Normal" weather in the 2011 IRP forecast is based on the weather in the 20-year period ending in 2009; the weather in the 2008 IRP was based on the weather in the 20-year period ending in 2006. Twenty-year average weather data is considered to be more representative of recent trends compared to a 30-year average. Weather data for Louisville and Lexington, Ky., as well as Bristol, Tenn., are gathered from NOAA to represent the weather in the LG&E, KU and ODP service territories, respectively.

For the 2011 IRP forecast, normal weather for the KU service territory incorporates an average of 4,574 HDDs and 1,208 CDDs each year over the forecast period (on a 65-degree base). The normal Lexington weather assumption was 4,525 HDDs and 1,219 CDDs in the 2008 IRP. Thus, the summers are slightly milder and the winters are slightly colder in the more recent 20-year period (1990-2009) in the KU service territory than the 20-year period utilized for the 2008 IRP (1987-2006).

Normal weather for the LG&E service territory is assumed to be 4,261 HDDs and 1,446 CDDs (also on a 65-degree base). Normal Louisville weather assumption in the 2008 IRP was 4,062 HDDs and 1,578 CDDs. In the LG&E service territory, the summers in the more recent 20-year period have been cooler than the 20-year period utilized for the 2008 IRP. The winters have been colder.

Service Territory Economic and Demographic Forecasts

In both the 2011 IRP and 2008 IRP, service-territory-level economic and demographic forecasts were developed based on county-level forecasts provided by Global Insight. As a result, the service-territory-level forecasts were consistent with the national-level forecasts from Global Insight.

Following is a summary of key assumptions made in Global Insight's 2010 Long-Term Macro Forecast, used by the Companies as macroeconomic background for the energy sales forecast in the 2011 IRP. Copies of the economic and demographic forecasts are attached as part of Technical Appendix in Volume II.

- *Trend Scenario*: The trend scenario is a projection that assumes no major mishaps between now and 2040. The projection is best described as depicting the mean of all possible paths the economy could follow, absent of any major disruptions such as oil price shocks or major changes in policy.
    - The trend scenario between 2011 and 2040 predicts GDP growth slightly below the historical rate for the last thirty years. Personal consumption and government spending are expected to fall slightly as well in comparison to the thirty year historical trend. There is an expected improvement in business investment along with an improvement in the balance of trade with exports growing at a faster rate than imports.
- *Demographics*: The trend scenario provides a demographic prediction which is based on the predictions provided by the Census Bureau. Global Insight predicts slowing population growth over the next thirty years. Increased life spans for both men and women point to an aging population.

Changes in Methodology

Several changes in forecasting methodology were incorporated in the 2011 IRP forecasts. These changes were made as part of on-going processes to increase the fidelity of the energy forecast. The following changes were made:

- In the 2008 IRP, total energy for each utility was allocated to hours based on an average 10-year load duration curve. In the 2011 IRP, the company used class-specific load profiles to develop its hourly demand forecasts. This approach enables the Company to better reflect demand-side management programs that impact the load profile of specific classes.
- The commercial forecasts for both LG&E and KU continue to group forecasts by rate class, but an average use-per-customer is developed using an SAE model. Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment.
- In the 2008 IRP, the appliance saturation forecasts were taken from the EIA for use in the Residential average-use-per-customer. In the 2011 IRP, responses to home appliance saturation surveys of both LG&E and KU customers were used to develop assumptions for the residential forecasting models.

DEMAND-SIDE MANAGEMENT

Energy Efficiency Expansion Filing

The Companies received approval for their current portfolio of energy efficiency programs from the KPSC on March 31, 2008, in Case No. 2007-00319. The Companies requested, and the KPSC approved, a seven-year plan for the programs in light of the significant investment in time and resources required to initiate operations, obtain participants, and achieve the projected demand and energy savings. The three years since the approval of these programs has granted greater insight into the challenges and obstacles associated with the outlined metrics within that program plan. As a result of the lessons learned, the Companies filed with the KPSC in Case No. 2011-00134, its DSM/EE Program Plan to enhance the following programs: Residential and Commercial Load Management; Commercial Conservation; Residential Conservation; Residential Low Income Weatherization Program; and Program Development and Administration.

In addition to enhancing several currently approved programs, the Companies plan to seek approval for additional DSM programs that will further increase energy and demand savings for the Companies. These programs include the Smart Energy Profile Program, Residential Incentives Program, and a Residential Refrigerator Removal Program. Upon approval of proposed program enhancements and new programming, the Companies DSM/EE portfolio of programs will operate through December 31, 2017 and allow the Companies to achieve 500MW of demand reduction by 2018.

Moreover, the following programs were approved by the KPSC in Case No. 2007-00319 and will remain unchanged: Residential High Efficiency Lighting, Residential New Construction, Residential and Commercial HVAC Diagnostic and Tune Up. These programs were not included in the plan filed in Case No. 2011-00134. The Companies propose to continue these existing programs through 2014 as these programs are categorized as "market transformation programs" or are currently operating satisfactorily within the approved program designs, and therefore do not warrant enhancements at this time.

2007 Responsive Pricing and Smart Metering Pilot Program

On March 21, 2007, LG&E filed an application with the KPSC in Case No. 2007-00117 requesting approval to develop a responsive pricing and smart metering pilot program. By Order dated July 12, 2007, the KPSC approved the Pilot that would serve up to two thousand customers. The duration of the pilot program, as the KPSC described it, was to be as follows: "[T]he Pilot will have an initial term of 3 years but will remain in effect until the KPSC modifies or terminates it."[1] LG&E's tariff sheets that apply to the pilot program, Rates RRP and GRP, contain language reflecting the duration approved by the KPSC.[2]

The pilot program's initial three-year term has now ended, having run from January 2008 to January 2011. Per the reporting requirements associated with the program, LG&E is now preparing for the KPSC's review a final report on the results obtained from the three-year study period. LG&E will file this report with the KPSC no later than June 30, 2011. Pursuant to the Commission's July 12, 2007 Final Order, the pilot program will continue, and the relevant rates and cost-recovery will remain in effect, until the KPSC modifies or terminates the program. LG&E believes leaving the program in effect for the time being not only comports

1 *Id.* at 6.
2 *See* LG&E P.S.C. Electric No. 8, Original Sheet No. 76 ("RRP … shall remain in effect until modified or terminated by order of the Commission."); LG&E P.S.C. Electric No. 8, Original Sheet No. 77 ("GRP … shall remain in effect until modified or terminated by order of the Commission.").

with the KPSC's Final Order, but is also necessary to allow the KPSC the opportunity to review and evaluate the results of the three-year study.

Additionally, the Companies' efforts in the area of responsive pricing and smart metering have taken an active role in helping to address the issues regarding federal standards of EISA 2007 through the Commission Staff Smart Meter and Smart Grid Guidance document in Case No. 2008-00408. Utilizing the noted efforts and the Responsive Pricing and Smart Metering Pilot Program final report, the Companies plan to formulate and make recommendations as to the future deployment of smart meter technology and time differentiated rates to ensure that deployment is at the speed of value.

Demand Reductions

The Companies received approval in Case No. 2007-00319 on March 31, 2008 for the enhanced versions of existing programs along with the addition of several new cost effective programs. The current portfolio of DSM/EE programs through the end of 2010 has achieved a demand reduction of 182 MW.

In Case No. 2011-00134, the Companies are seeking approval for additional DSM programs that will further increase demand reduction. The seven year plan for the proposed programs will provide an additional 309 MW of demand reduction providing an overall reduction of 491 MW, placing the Companies on target to meet the 2008 IRP cumulative demand reduction of 539 MW.

Resource Analytical Assessment

The analysis of potential DSM options in the case to be filed with the KPSC in early 2011 was performed using DSMore, a PC-based software package developed by Integral Analytics, Inc. This software has replaced DS Manager, which was used to provide the benefit/cost calculations in prior expansion filings. The benefit/cost calculations contained in DSMore provides more robust analytics surrounding weather and market conditions and a more transparent platform to understand the underlying calculations associated with the benefit/cost tests

RENEWABLE ENERGY

Green Energy

Since the 2008 IRP, a number of modifications to the Green Energy Program were submitted to the KPSC and approved in Case No. 2009-00467 on February 22, 2010. These modifications include ending our contract with 3Degrees and moving the purchasing of the renewable energy certificates ("RECs") in-house, removing the fixed kilowatt-hour ("kWh") per block for both the Small Green Energy participants and the Large Green Energy participants, and removing the one-year commitment requirement for the Large Green Energy customers. These changes were made to increase value to the participants in the program and have led to a dramatic increase in a per kWh of environmental benefits from either 300 or 1,000 kWh to roughly 800 or 2,600 kWh per program per block.

RELIABILITY CRITERIA

In the Joint Companies 2008 IRP, the Companies used a combined target reserve margin of 14 percent, with a recommended range of 13 percent to 15 percent. In the current assessment and acquisition study, the Companies have increased the combined target reserve margin to 16 percent, with a recommended range of 15 percent to 17 percent. A discussion of the reliability criteria is found in the report titled *LG&E and KU 2011 Reserve Margin Study* (April 2011) contained in Volume III, Technical Appendix.

WHOLESALE POWER MARKET

Generation Outlook

As the U.S. power industry emerged from the "Great Recession" of December 2007 to June 2009, national capacity expansion concerns generally shifted in the short term from meeting desired reserve requirements to satisfying state renewable portfolio requirements. Key uncertainties that will impact the future structure of the industry are the pace of economic recovery, the game changing nature of newly recognized domestic shale gas resources and an uncertain pace and magnitude of regulatory change.

From 2000-2007 U.S. energy demand grew at an average annual rate of approximately 1.4 percent and peak demand grew at a 1.9 percent average annual rate. The '07-'09 recession reduced load growth to the point that U.S. peak load may not exceed its previous high of 2007 before 2012. Cambridge Energy Resource Associates ("CERA") estimates that 2010 national non-coincident peak demand was 55,000 MW lower than had been expected in 2008, while capacity additions were only 16,000 MW lower than expected, leading to an increase in the national reserve margin in 2010 from 21 percent to 28.6 percent.

As the nation's economy recovers, there is significant uncertainty about the rate of growth of peak demand and capacity additions. CERA's latest forecast expects national peak demand to rise at a 1.9 percent annual rate from 2010 through 2015, while the EIA expects peak demand to grow at just a 0.1 percent annual rate for the same period.

With building to meet reserve margin requirements less of a concern in most U.S. regional markets, the construction of new capacity has slowed. CERA estimates that approximately 31,000 MW of generating capacity is currently under construction in the U.S., approximately 20 percent less than just over two years ago. Over 15,000 MW of this capacity began construction prior to the recession. By 2015, CERA anticipates total capacity additions in the U.S. of approximately 100,000 MW. During the same period, 33,000 MW of capacity are expected to be retired. The EIA anticipates only 48,000 MW of capacity to be added by 2015, with 24,000 MW of offsetting retirements.

Most of the new capacity in either forecast is intended to meet state specific renewable power targets and to take advantage of policy incentives. CERA expects total U.S. renewable capacity to increase by 49,000 MW from 2010 to 2015, of which wind generation capacity is expected to provide 37,000 MW or 76 percent. At an average of approximately 6,000 MW per year after 2010, this is a slightly slower pace of addition for wind capacity than was seen in 2008-2009 of approximately 9,000 MW per year, reflecting challenging economic conditions and transmission constraints. Solar capacity begins to slowly increase, with additions of 8,000 MW. Approximately 13,000 MW of coal-fired plants are either completed or under construction. Aside from the Watts Bar Unit #2 addition by TVA in 2013, little contribution is expected from nuclear capacity additions by 2015, given a low gas price outlook and a reduced likelihood of significant carbon dioxide ("CO_2") pricing. With coal and nuclear generation expansion facing significant constraints, gas-fired generation capacity provides the least expensive new-build option, contributing 32,000 MW by 2015. Approximately two-thirds of the new gas capacity is expected to be in the form of combined-cycle units. Retirements through 2015 will be primarily of coal-fired capacity, as 18,000 MW retire in the face of increased competition from efficient combined-cycle gas generators in a low-cost gas environment and impending but uncertain environmental regulations. In the EIA outlook, renewable capacity increases 22,000 MW by 2015. Coal-fired additions total 11,500 MW. Gas-fired units add 13,000 MW with combined-cycle units contributing approximately 60 percent of the increase. In addition to the Watt's Bar Unit #2 addition, upgrades at existing nuclear facilities contribute an additional 3,500 MW. In the EIA's retirements outlook, 14,000 MW are oil and gas steam units, 7,000 MW are coal-fired, and 3,500 are gas-fired combustion turbines.

The outlook for domestic gas resources has changed dramatically over the last three years. In 2007, CERA was anticipating that essentially all growth in North American gas supply would come from liquefied natural gas ("LNG") imports. In 2008, the Potential Gas Committee estimated that proven reserves and potential recoverable resources were over 500 trillion cubic feet ("Tcf") higher than their 2006 estimate, driven by improvements in the economics of shale gas extraction. CERA in 2009 estimated that total shale resources were ~1,000 Tcf higher than the Potential Gas Committee's estimate, pushing the total estimated North American resource base to nearly 3,000 Tcf, equivalent to approximately 100 years of current North American consumption. The U.S. market has seen this potential begin to be realized, as lower 48 'unconventional gas' production increased from approximately 50 billion cubic feet ("Bcf") per day in January, 2007 to almost 59 Bcf per day by December, 2010.

The shale resource is considered a game changer because in addition to its size, improvements in drilling and hydraulic fracturing technologies have led CERA to estimate that nearly 900 Tcf of this resource could be developed at a full-cycle cost of less than $4/MMBtu. Therefore, future gas prices will not have to rise significantly to support long-term investments. Prior to the dramatic expansion of domestic shale gas production, the U.S. anticipated receiving substantial amounts of imported LNG. This is unlikely given the increase in shale gas supplies.

U.S. energy and environmental policy has backed away from the prospect of stringent climate change legislation, and is now driven by a regulatory approach of the Environmental

Protection Agency ("EPA"). The impact of any EPA regulation on CO_2 is highly uncertain. The application of best available control technology ("BACT") to existing power plants may not have much near-term impact but would likely evolve over time as new technologies are proven. New source performance standards ("NSPS") could be applied to both new and existing sources with a wide range of potential outcomes. EPA regulations covering hazardous air pollutants, coal waste, and cooling water are also under development. The potential combined cost impact of these regulations could have a significant impact on both coal plant retirements and the attractiveness of new coal plant investments.

Transmission Outlook

There has continued to be an absence of high-voltage interregional transmission system enhancements in the Midwest. This lack of transmission enhancements has resulted in less and less available transfer capability available for wholesale market transactions. While there has been an increase in efforts to promote regional transmission planning and expansion throughout the Midwest and the Eastern Interconnect for inter-state sales which may address this issue, these efforts will take several years to come to fruition. However, the Midwest Independent System Operator, Inc. ("MISO") has recently received conditional FERC approval for a new category of transmission projects designated as Multi Value Project for projects that are deemed to enable the reliable and economic delivery of energy to support documented energy policy mandates or laws that address development of a robust transmission system affecting multiple transmission zones. The cost of such approved projects will be spread to all load and exports in the MISO footprint.

The MISO market and the independent system operator ("ISO") originally founded for Pennsylvania, New Jersey, and Maryland ("PJM") market as well, have created after-the-fact price information for energy traded between Regional Transmission Organizations ("RTOs") or non-RTO counterparties. These markets provided very short term physical price transparency, and have in fact introduced additional price risks like after-the-fact changes to locational marginal pricing settlements and reserve sharing group adders. There has been significant development of financial markets in the various ISOs through the Intercontinental Exchange trading system. The system provides forward price discovery, transparency and liquidity at the financial trading "hubs" for both on-peak power and off-peak power.

The MISO launched its Ancillary Services Market ("ASM") on January 6th, 2009. Concurrently, the MISO became the region's Balancing Authority. Integration of ASM into market operations made possible the central dispatch of regulated reserves, spinning reserves and supplemental reserves based on bids and offers cleared. The startup of the Midwest ASM did impact the makeup of regional reserve sharing groups, which resulted in LGE and KU forming a group within Tennessee Valley Authority ("TVA") and East Kentucky Power Cooperative.

Changes in the Primary Energy Balance

With the average delivered price of natural gas falling from $9.10/MMBtu in 2008 to $5.18/MMBtu in 2010 (EIA data, 2009$), natural gas increased its share of fuel consumption for electric power generation from 20 percent in 2008 to 23 percent in 2010. Despite EIA's expectation that the delivered price of gas to the electric power sector will track at a sub $5/MMBtu level in real terms through 2015, EIA expects incremental generation to accrue to renewable sources which increase their share of power sector generation from 9.4 percent in 2010 to 12.5 percent in 2015. Fossil fuel usage in general is expected by the EIA to decline during this period.

CERA estimates that the share of generation from renewable sources will increase to 12 percent in 2015. Coal-fired generation is expected to increase by 4.6 percent from 2010 to 2014, and then fall by 5 percent in 2015 as implementation begins of the EPA's CO_2, NO_x, and sulfur dioxide ("SO_2"), and cap and trade programs. Coal's share of total generation generally declines over the period from 47 percent to 42 percent. Gas is expected to provide over two-thirds of incremental generation with renewable generation contributing 30 percent.

UPGRADES TO HYDROELECTRIC STATIONS

Ohio Falls

The 2008 IRP indicated that LG&E was in Phase 3 of a project to rehabilitate the eight units at the Ohio Falls Station. Rehabilitation of each unit will result in a nameplate capacity rating increase from 10 MW to 12.58 MW per unit. However, the Ohio Falls Station is a run-of-river facility that is subject to actual river flow. This project is expected to increase the planned summer capacity of this station from 48 MW to 64 MW. Rehabilitation of Ohio Falls Units 6 and 7 has already been completed. Rehabilitation work on Unit 5 is scheduled to begin in 2011 and the remaining five units are planned to be completed by the end of 2014.

Dix Dam

Since the 2008 IRP, KU has also undertaken a project to overhaul the three units at the Dix Dam Station. This project involves rewinding the generators, refurbishing the turbine sections, and upgrading controls. The overhauls will result in an expected capacity increase on each unit from 8 to 10 MW, for a total increase of 6 MW, at the current lake level target range. The overhaul on Unit 3 was completed in 2009 with final testing completed in February 2010. Unit 2 is expected to be completed in 2011 and Unit 1 is anticipated to be completed in 2012.

In addition to the rehabilitation efforts at the Ohio Falls and Dix Dam Stations, the Companies continue to monitor potential hydro opportunities. However, sites for additional conventional hydro facilities on the Ohio River are limited.

TRANSMISSION SYSTEM OPERATOR

During July 2006, the KPSC and FERC authorized the Companies to exit the MISO. Upon exiting MISO, the Southwest Power Pool ("SPP") served as the Independent Transmission Operator ("ITO") and TVA served as the reliability coordinator for the Companies. In October 2009, SPP notified the Companies of their intent to terminate the contract effective August 31, 2010. Although the Companies initially sought to regain operational control of their transmission assets, the Companies ultimately entered into a new contract with SPP extending the agreement until August 31, 2012 in order to avoid unacceptable delay and uncertainty. The current agreement with SPP terminates on August 31, 2012 and requires the Companies to make the necessary FERC filings to effectuate the termination of the SPP arrangement and to seek approval for a replacement arrangement prior to August 31, 2012. Therefore, the Companies in February 2011 solicited feedback, suggestions, and comments from stakeholders in order to develop and issue a Request for Information ("RFI") to potential bidders. The Companies evaluated responses to the RFIs and during March 2011, sent out an RFP to interested and potential providers. RFP responses are due to the Companies no later than April 26, 2011.

RESEARCH AND DEVELOPMENT

FutureGen

In the 2008 IRP, it was discussed that in 2006, E.ON U.S., the parent company of LG&E and KU at the time, had announced that it committed $25 million to join the FutureGen Industrial Alliance. This alliance was a non-profit consortium of energy companies partnering with the U.S. Department of Energy ("DOE") to site and develop FutureGen, the world's first coal fired near-zero emission power plant. The goal of the project was to move near-zero emissions power production from concept to a commercial reality. The project cost was to be split 74 percent DOE funding and 26 percent FutureGen Alliance funding as defined in the Co-Operative Agreement between the two parties.

Early in 2010, the DOE declined to renew the agreement with the FutureGen Industrial Alliance and instead, executed a new FutureGen 2.0 agreement with Ameren to repower an existing pulverized coal unit using Babcock and Wilcox oxy-combustion technology. On September 28, 2010 the FutureGen Industrial Alliance signed a new agreement with the DOE to build the FutureGen 2.0 CO_2 pipeline network and CO_2 storage site. Although the Companies remain in the FutureGen Industrial Alliance, the scope of the consortium's involvement in FutureGen 2.0 has been greatly reduced and the expected monetary contribution has also been reduced to approximately ten percent of formerly anticipated contributions.

Greenhouse Gas Research

Other research and development projects of the Companies include efforts in reducing greenhouse gases. In 2008, LG&E and KU worked with the University of Kentucky's Center for Applied Energy Research ("CAER") to setup the Carbon Management Research Group

("CMRG"). The Companies plan to contribute $200,000 per year through 2017 to the CMRG and CAER to support fundamental research on carbon capture technologies.

Also in 2008, the Companies, along with Conoco Phillips, Peabody Coal and others, formed the Western Kentucky Carbon Storage Foundation ("WKCSF") to provide funding for the Kentucky Geological Survey ("KGS") to drill a well in Hancock County to determine the feasibility of CO_2 storage in the western Kentucky coal field region. The three principal members of the WKCSF each contributed approximately $1.8 million each to the effort and the Commonwealth of Kentucky funded approximately $1.3 million. The well and initial testing was completed in 2009 and additional testing was funded by the DOE in 2010. The well was plugged in late 2010 and the WKCSF was dissolved thereafter. KGS continues to monitor the well.

The Companies are also charter members of the Electric Power Research Institute's ("EPRI") "Coal Fleet for Tomorrow" program. This program is a research effort to develop a portfolio of advanced coal technologies which are more accessible and affordable for power producers and society.

In 2010, LG&E and KU made commitments to provide matching funds for two DOE carbon capture demonstration studies. The first study is a self-concentrating absorbent process developed by 3H Company with a two year annual commitment of $114,000. The second is an amine process under development by the University of Texas at Austin with a three year annual commitment of $39,000.

ENVIRONMENTAL REGULATIONS

Since the 2008 IRP, there have been significant changes in the environmental regulation arena. These regulations are discussed in detail in Sections 8.(5)(b) and 8.(5)(f).

Clean Water Act - 316(b) - Regulation of cooling water intake structures

Since the 2008 IRP, the impacts of cooling water intakes on fish populations were further studied. EPA is currently drafting a revised 316(b) regulation which was released in proposed form on March 28, 2011 and is anticipated to be finalized by July 2012. The Companies expect both industry and environmental groups will utilize the court system to again challenge the new rule and possibly delay implementation deadlines. The regulation will address both impingement and entrainment issues, thus possibly affecting all Company facilities, including those already equipped with closed cycle cooling (cooling towers).

Clean Water Act – Effluent Guidelines

Since the 2008 IRP, EPA further studied the issue and in 2009, EPA determined that it would revise the steam-electric industry effluent standards. In June 2010, EPA issued a very detailed questionnaire to over 500 utilities across the nation that was aimed at assisting EPA in revising the standards. Based on the depth of the questionnaire, it is anticipated that EPA could take several years to digest the information. Proposed draft regulations are not expected until 2012 with potential promulgation in late 2013. Those potential regulations could require capital investments for treatment facilities within the time period of this IRP document.

Clean Air Interstate Rule/ Clean Air Transport Rule

Since the 2008 IRP, the Clean Air Interstate Rule ("CAIR") was remanded back to EPA for reconsideration in December 2008. The first phase of the rule was implemented in 2009 (NO_x) and 2010 (SO_2) as a "stop-gap" measure in order to continue a program of emission reductions.

In the summer of 2011, EPA is expected to promulgate its replacement to the CAIR rule called the Clean Air Transport Rule ("CATR"). Current proposals indicate that CATR will have similar reduction targets as CAIR. However, those targets will be required sooner than CAIR. The first compliance year will likely be 2012 (instead of 2015) and additional reduction will likely be required starting in 2014 (instead of 2018). Additionally, the proposals indicate that a new trading program for SO_2 allowances will be developed. Previously banked allowances will not be applicable to the new program. CATR is also expected to have very limited interstate trading abilities.

Clean Air Mercury Rule / Hazardous Air Pollutant Regulations

Since the 2008 IRP, the Clean Air Mercury Rule ("CAMR") was vacated on February 8, 2008. Several legal proceedings kept open the possibility that CAMR might have been brought back, until February 2009 when EPA decided to remove their petition for a hearing with the Supreme Court. EPA cited the formulation of new rules to regulate hazardous air pollutant emissions from power plants.

Those new rules will establish the National Emission Standards for Hazardous Air Pollutants ("HAPs") for the coal- and oil- fired electric utility industry and set emission limits based on the maximum achievable control technology ("MACT") for the industry. In January 2010, EPA issued an information collection request to the electric utility industry to gather data on what controls facilities had in place and what levels of emissions were emitted. On March 16, 2011, EPA signed the proposed regulation. As proposed, the regulation places numeric limits on mercury, non-mercury metallic HAPs, and acid gas HAPs emissions. The proposal also sets work practice standards to minimize and reduce HAPs emissions. After the regulation is published in the Federal Register, there will be a 60-day public comment period. EPA will review those comments and then issue a final regulation. By court order, the regulation has to be finalized by November 16, 2011.

National Ambient Air Quality Standards

SO_2

Since the 2008 IRP, EPA published a final rule on June 22, 2010 to revise the then current primary SO_2 national ambient air quality standards ("NAAQS"). The new NAAQS for SO_2 is a 1-hour primary (i.e., health based) SO_2 standard of 75 parts per billion ("ppb"), based on the three year average of the fourth highest of the 1-hour maximum concentrations. Based on historical 3-hour SO_2 data monitored for the current "secondary" SO_2 NAAQS, it is likely that Jefferson County, Kentucky will be designated in non-attainment of the new standard. EPA issued official guidance on how to make the non-attainment designations on March 24, 2011. States have until June 3, 2011 to submit their designation recommendations. It appears that EPA will allow air dispersion modeling rather than relying solely on ambient air monitoring.

The guidance addresses the preferred modeling procedures that EPA recommends both for identifying nonattainment area boundaries and for demonstrating that areas without violating monitors are in attainment. Without dispersion modeling results to support the attainment designations, most areas in the country are expected to initially be designated as "unclassifiable." As stated above, based on the existing network of SO_2 monitors in Kentucky, only monitors in Jefferson County are currently showing violations for the new NAAQS. Therefore, it is likely that Kentucky will only propose Jefferson County as nonattainment with the rest of the State proposed as unclassifiable.

Kentucky must incorporate this new NAAQS into its state implementation plan ("SIP"). Additionally, the SIP must contain a plan to get any non-attainment areas into attainment with the standard by June 2017, meaning controls may be needed by 2016.

Nitrogen Dioxide

Since the 2008 IRP, EPA published a final rule which revised the primary NAAQS for nitrogen dioxide (NO_2) on February 9, 2010. It became effective on April 12, 2010. EPA adopted a new 1-hour standard of 100 ppb and retained the existing annual average standard of 53 ppb. Based on existing air quality data in Kentucky, all areas are currently well below these standards. However, the new rule stipulated the establishment of additional new air quality monitor locations. Emphasis is to be placed on locating these monitors near major roadways in large cities where the highest concentrations are expected; but additional monitors to represent community-wide air quality may also be required in large cities. EPA is also planning to evaluate whether changes to Prevention of Significant Deterioration ("PSD") air quality increments are needed. If so, this could place further limits on the allowable amount of increased emissions from a new or modified source.

Kentucky must incorporate this new NAAQS into its SIP. Additionally, the SIP must contain a plan to get any non-attainment areas into attainment with the standard by June 2017; meaning controls may be needed by 2016.

Ozone

Since the 2008 IRP, EPA again lowered the primary NAAQS for ozone to 0.075 parts per million ("ppm") on March 12, 2008. Several counties in Kentucky have recent monitoring data that are above that level. EPA was to make final designations in March 2011. However, due to a reconsideration of the standards (i.e., the new proposed standards in January 2010 mentioned below) the designations have not been made. If designations are made, states would then have three years to submit a SIP that incorporates the new NAAQS and plans for bringing all areas into attainment with the standard. It is believed that CAIR, which is to be replaced by

CATR, and other federal regulations along with some proposed local initiatives will help bring those counties into compliance by the attainment deadlines (i.e., 2016). Unfortunately, EPA continued to review the effectiveness of the ozone NAAQS.

On January 7, 2010, EPA proposed an even lower primary ozone standard to a range of 0.060 and 0.070 ppm measured over eight hours. At the same time, EPA proposed a new seasonal secondary ozone standard in the range of 7 to 15 ppm. EPA is planning to name the new standards by the end of July 2011. Once the final standard is picked, non-attainment areas will again be designated. Kentucky will then have three years (i.e., 2014) to submit a SIP incorporating the new NAAQS and plans for brining all areas into attainment with the new standard. Typically, non-attainment areas will have at least three years to obtain attainment status.

PM / PM$_{2.5}$

Since the 2008 IRP, the D.C. Circuit Court of Appeals remanded the 2006 NAAQS back to EPA in February 2009. As a result, EPA has been working on a proposed revision that is expected in 2011. Of additional note, in October 2009, EPA re-designated all counties in Kentucky as attainment with the 24-hour standard, based on a re-evaluation of monitoring data performed and submitted by the Kentucky Division for Air Quality.

Greenhouse Gases

Since the 2008 IRP, EPA issued its mandatory greenhouse gas ("GHG") emissions reporting rule on September 22, 2009. Facilities with carbon dioxide equivalent ("CO_2e") of more than 25,000 metric tons or an aggregated maximum rated heat input capacity of more than 30 MMBtu/hr are to begin reporting emission values to EPA by September 30, 2011. Sources required to report include: power plants, miscellaneous stationary combustion sources, and emissions pertaining to the gas supplied to customers of the Companies. On November 2, 2010, the reporting regulation was expanded to include reporting of sulfur hexafluoride ("SF_6") emissions from electric transmission and distribution equipment and methane, carbon dioxide, and nitrogen oxide emissions from natural gas processing plants, natural gas transmission compression operations, natural gas underground storage, and natural gas distribution activities. Reporting for these activities will begin in March 2012.

On March 13, 2010, EPA issued the greenhouse gas "Tailoring Rule" which became effective on January 2, 2011. This rule sets thresholds for requiring permitting of greenhouse emissions. In December 2010, EPA also announced a plan to propose NSPS regulations for GHG emissions from power plants by July 26, 2011 with potential finalization to occur in May 2012. These new rules would set emission requirements for new and modified electric generating units ("EGU") and set guidelines for existing EGUs. EPA has indicated that these rules will be coordinated with other rules issued near the same time period (i.e., hazardous air pollutants, CATR). However, until more information is provided, the potential impact of these rules is uncertain.

Coal Combustion Residuals

Since the 2008 IRP, EPA has begun to investigate tightening regulation of coal combustion residuals ("CCR") from the electric utility industry. Within the next few years, regulatory changes are expected in the permitting and management practices for CCR from coal ash and flue gas desulphurization ("FGD") systems, whether managed in ash treatment basins (ash ponds) or landfills.

In June 2010, EPA published a co-proposal requesting comments on two different approaches for the management of CCR from coal-fired electric utilities. The first option would manage CCR as hazardous waste under Subtitle C of the Resource Conservation and Recovery Act ("RCRA") and require federal oversight with no use of surface ponds for containment. The second option would manage CCR as a non-hazardous solid waste under RCRA Subtitle D with state oversight of federal minimum standards. Lined surface impoundments or lined contained landfills could be used in the second option.

EPA will likely select a final option and publish the proposed regulations in late 2011. When the final regulations are published, the regulation will likely have a five year implementation window. This means that existing CCR storage and management facilities would require upgrade or closure.

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7. LOAD FORECASTS

Kentucky Utilities Company

7.(1) Specification of Historical and Forecasted Information Requirements by Class

The data submissions in the following subsections conform to the specifications provided in Section 7.(1) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible.

7.(2) Specification of Historical Information Requirements

The data submissions in the following subsections conform to the specifications provided in Section 7.(2) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible.

7.(2)(a) KU Average Number of Customers by Class, 2006-2010

	2006	2007	2008	2009	2010
Total Residential	409,612	413,747	415,717	420,028	422,858
Commercial	77,804	79,359	79,996	80,357	81,223
Industrial	1,883	1,855	1,834	1,957	2,172
Public Authority*	7,174	7,135	7,443	7,162	7,193
Utility Use & Other**	1,470	1,460	1,434	1,376	1,381
Virginia Retail	29,965	29,956	30,017	29,738	29,624
Req. Sales for Resale	12	12	11	12	12
Total Customers	527,920	533,524	536,452	540,630	544,463

* Includes Municipal Pumping

** Includes Lighting

7.(2)(b) KU Recorded and Weather-Normalized Annual Energy Sales (GWh) & Energy Requirements (GWh)

	2006	2007	2008	2009	2010
SYSTEM BILLED SALES:					
Recorded	20,831	21,625	21,139	20,011	21,921
Weather Normalized	21,041	21,393	21,050	20,206	21,291
SYSTEM USED SALES:					
Recorded	20,675	21,643	21,190	20,260	21,938
Weather Normalized	20,946	21,439	21,079	20,398	21,234
ENERGY REQUIREMENTS:					
Recorded	22,014	22,993	22,511	21,476	23,467
Weather Normalized	22,163	22,255	22,345	21,613	22,764
SALES BY CLASS:					
Residential	5,908	6,432	6,384	6,165	6,729
Commercial	4,270	4,577	4,520	4,319	4,365
Industrial	6,083	6,049	5,778	5,455	6,245
Lighting	52	54	56	52	54
Public Authorities	1,472	1,552	1,566	1,510	1,581
Requirement Sales for Resale	1,978	2,059	1,971	1,848	2,002
KENTUCKY Retail	19,764	20,723	20,275	19,349	20,976
VIRGINIA Retail	911	919	916	911	962
SYSTEM LOSSES	1,323	1,333	1,243	1,191	1,507
Utility Use	16	17	22	25	23
ENERGY REQUIREMENTS	22,014	22,993	22,456	21,476	23,467

7.(2)(c) KU Recorded and Weather-Normalized Peak Demands (MW)

	2006	2007	2008	2009	2010
SUMMER					
Actual	4,150	4,333	3,878	3,888	4,323
Normalized	4,102	4,210	4,074	4,001	4,202
	2005/2006	**2006/2007**	**2007/2008**	**2008/2009**	**2009/2010**
WINTER					
Actual	4,019	4,300	4,476	4,640	4,344
Normalized	4,178	4,342	4,570	4,461	4,282

7.(2)(d) KU Energy Sales and Coincident Peak Demand for Firm and Contractual Commitment Customers

	2006	2007	2008	2009	2010
Energy Sales (GWh)	19,087	20,290	19,866	18,941	20,452
Coincident Peak Demand (MW)	4,150	4,333	3,809	3,829	4,253

7.(2)(e) KU Interruptible Customers Energy Sales and Combined Company Coincident Peak Demand

	2006	2007	2008	2009	2010
Energy Sales (GWh)	677	434	408	408	525
Coincident Peak Demand (MW)	61	63	69	59	70

7.(2)(f) KU Annual Energy Losses (GWh)

	2006	2007	2008	2009	2010
Annual Energy Loss	1,323	1,333	1,243	1,191	1,507
Loss Percent of Energy Requirements	6.4%	6.2%	5.9%	5.9%	6.9%

7.(2)(g) Impact of Existing Demand Side Programs

Impacts of the existing demand-side programs on energy and demand requirements are estimated in Table 8.(3)(e)(3).

7.(2)(h) Other Data Illustrating Historical Changes in Load and Load Characteristics

Actual sales and customer data as reported in tables 7.(2)(a-f) above are calculated using the Company's FERC Form 1 filings as the basis for class segmentation. These numbers are not weather normalized. Historical actual calendar (not weather normalized) average energy use-per-customer by class is shown in Table 7.(2)(h)-1. Historical percentage share of class sales (not weather normalized) to total energy sales is presented in Table 7.(2)(h) 2.

Table 7.(2)(h)-1
KU Average Annual Use-per-Customer by Class (kWh)

	2006	2007	2008	2009	2010
Residential	14,423	15,546	15,357	14,678	15,913
Commercial	54,884	57,668	56,503	53,748	53,741
Industrial	3,230,462	3,261,175	3,150,491	2,787,430	2,875,230
Public Authority	205,255	217,554	210,399	210,835	219,797
Utility Use & Other	35,642	37,181	39,052	37,791	39,102

Table 7.(2)(h)-2
KU Percentage of Class Sales to Total Energy Sales

	2006	2007	2008	2009	2010
Total Residential	29%	30%	30%	32%	31%
Commercial	21%	21%	21%	21%	20%
Industrial	29%	28%	27%	27%	27%
Public Authority	7%	7%	7%	7%	7%
Utility Use and Other	0%	0%	0%	0%	0%
Virginia Retail	4%	4%	4%	4%	4%
Req. Sales for Resale	10%	10%	9%	9%	9%
Total Company	100%	100%	100%	100%	100%

KU Kentucky Retail Residential Sales

Changes in KU's Kentucky retail residential sales are driven by changes in both average use-per-customer and incremental customer growth. Since 2006, the total number of residential customers has increased at an average annual rate of 0.8 percent, while average annual use-per-customer has remained flat on a weather-normalized basis.

Table 7.(2)(h)-3 shows estimates of KU's historical appliance saturation trends in the residential class.

Table 7.(2)(h)-3
KU Residential Electric Appliance Saturations (percent)

APPLIANCE	2003	2007	2010
Refrigerator	100	100	100
Refrigerator (2 or more)	-	22	24
Freezer	50	43	43
Home Computer	48	54	74
Range (Electric)	89	89	87
Microwave Oven	95	95	98
Dishwasher	58	58	67
Clothes Washer	89	84	93
Clothes Dryer (Electric)	85	88	89
Water Heater (Electric)	76	61	68
Dehumidifier	16	11	19
Central Air Conditioning	58	68	68
Electric Heat	47	51	55

KU Kentucky Retail Commercial Energy Sales

The KU's Kentucky retail commercial class has experienced modest growth in the number of customers and a slight decline in use-per-customer. From 2006 to 2010, the total number of customers has grown at an average annual rate of 1.1 percent. Use-per-customer has declined at an average annual rate of 1.3 percent over the same time period on a weather-normalized basis.

KU Kentucky Retail Industrial Energy Sales

Growth in KU's Kentucky retail industrial class has come entirely from growth in average use-per-customer. Since 2006, the number of customers in the industrial class has increased at an average annual rate of 3.6 percent. In spite of this increase, total sales to this class have only increased by an average annual rate of 0.5 percent. This growth is primarily the result of the growth in sales to a few of KU's largest industrial customers.

KU Kentucky Retail Lighting Energy Sales

Lighting sales are a small component of overall energy sales and have remained broadly flat over the 2006-2010 period.

KU Virginia Energy Sales

Virginia sales have demonstrated very low growth in recent years, and experienced a slight decline of an annual average rate of 0.2 percent since 2006. The total number of customers has declined and use-per-customer (weather-normalized) grew at an average annual rate of approximately 0.2 percent over the 2006-2010 period.

KU Wholesale Energy Sales

Wholesale (municipal) weather-normalized sales have grown at an annual average rate of 0.3 percent since 2006. Sales to the wholesale sector divided into three categories: Primary voltage, transmission voltage, and the City of Paris.

7.(3) Specification of Forecast Information Requirements

The information regarding the energy sales and peak load forecasts in the following subsections conform to the specifications outlined in Section 7.(3) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible.

7.(4) KU Energy and Demand Forecasts

7.(4)(a) KU Forecasted Sales by Class and Total Energy Requirements (GWh)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	6,414	6,467	6,540	6,602	6,729	6,860	6,961	7,070	7,187	7,306	7,410	7,529	7,636	7,803	7,936
Commercial	4,635	4,725	4,820	4,889	4,993	5,085	5,155	5,238	5,335	5,436	5,509	5,608	5,688	5,797	5,894
Industrial	5,849	6,075	6,260	6,395	6,520	6,596	6,684	6,792	6,919	7,038	7,137	7,255	7,368	7,494	7,613
Total C/I	10,485	10,800	11,080	11,283	11,513	11,682	11,840	12,030	12,254	12,474	12,646	12,863	13,056	13,291	13,506
Public Authority	1,587	1,625	1,656	1,676	1,698	1,714	1,729	1,749	1,776	1,805	1,827	1,855	1,879	1,908	1,935
Utility Use and Lighting	84	85	86	87	88	89	90	91	92	94	95	96	97	98	99
Sales for Resale	2,019	2,038	2,052	2,062	2,066	2,075	2,087	2,103	2,120	2,133	2,148	2,165	2,184	2,203	2,218
Total Kentucky	20,589	21,016	21,414	21,711	22,095	22,419	22,707	23,043	23,430	23,810	24,127	24,508	24,851	25,302	25,694
Virginia	917	924	930	935	943	953	960	967	974	983	990	998	1,006	1,014	1,024
Total KU Calendar Sales	21,506	21,940	22,344	22,646	23,039	23,372	23,667	24,010	24,405	24,793	25,116	25,506	25,858	26,317	26,718
Utility Use and Losses	1,409	1,441	1,476	1,527	1,587	1,638	1,673	1,698	1,722	1,756	1,790	1,816	1,848	1,875	1,907
Total Requirements	22,915	23,381	23,821	24,173	24,625	25,010	25,340	25,708	26,127	26,549	26,907	27,322	27,706	28,192	28,625

7.(4)(b) KU Summer and Winter Peak Demand (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Summer	4,146	4,237	4,341	4,417	4,497	4,522	4,584	4,663	4,780	4,895	4,953	5,022	5,109	5,244	5,361
	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25
Winter	4,711	4,706	4,695	4,786	4,878	4,963	4,974	5,057	5,099	5,241	5,390	5,447	5,497	5,609	5,718

7.(4)(c) KU Monthly Sales by Class and Total Energy Requirements (GWh)

	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	**2011**	764	621	544	394	380	495	608	599	467	381	476	685	6,414
	2012	771	626	548	397	383	500	613	604	471	384	480	690	6,467
Commercial	**2011**	406	353	358	341	374	411	445	460	385	373	341	389	4,635
	2012	413	360	365	348	381	419	454	468	392	380	348	397	4,725
Industrial	**2011**	438	453	484	488	510	518	483	511	470	526	485	483	5,849
	2012	455	471	503	507	530	538	501	530	488	546	503	502	6,075
Total C/I	**2011**	843	806	842	829	884	929	928	970	855	899	825	872	10,485
	2012	868	830	868	855	911	957	955	999	881	926	851	898	10,800
Public Authority	**2011**	129	117	120	118	135	140	147	158	147	132	116	128	1,587
	2012	132	120	123	121	138	144	150	162	150	135	118	131	1,625
Utility Use and Other	**2011**	8	7	7	6	6	6	5	7	6	8	8	9	84
	2012	8	7	7	6	6	6	6	7	7	8	8	9	85
Sales for Resale	**2011**	178	164	163	148	155	172	196	199	180	152	145	168	2,019
	2012	180	165	164	150	157	174	197	201	182	153	146	170	2,038
Total Kentucky	**2011**	1,922	1,715	1,677	1,495	1,560	1,743	1,885	1,934	1,656	1,571	1,570	1,862	20,589
	2012	1,958	1,749	1,712	1,528	1,595	1,781	1,922	1,973	1,690	1,607	1,604	1,898	21,016
Virginia	**2011**	107	94	84	68	62	62	65	69	61	67	76	102	917
	2012	108	95	85	69	63	62	66	69	62	67	77	102	924
Total KU Calendar	**2011**	2,029	1,809	1,761	1,563	1,622	1,805	1,950	2,002	1,717	1,638	1,647	1,963	21,506
	2012	2,066	1,843	1,797	1,597	1,658	1,843	1,988	2,042	1,752	1,674	1,681	2,000	21,940
Requirements	**2011**	186	166	163	146	153	171	184	192	161	156	151	2,008	3,836
	2012	188	168	165	148	156	174	187	195	163	158	153	2,039	3,894

7.(4)(d) Forecast Impact of Demand-Side Programs

The impacts of existing and future demand-side programs on both energy sales and peak demands are estimated in Table 8.(3)(e)-3. The energy sales forecasts presented in the preceding sections do not include the impacts of those programs. The DSM-related adjustments to summer and winter peak demand and annual energy forecasts are shown in Tables 8.(4)(a)-1, 8.(4)(a)-2 and 8.(4)(b) for both LG&E and KU combined.

7.(5) Historical and Forecast Information for a Multi-State Integrated Utility System

7.(5)(a) Historical Information for a Multi-State Integrated Utility System

Virginia energy sales constitute less than 5 percent of total KU sales. Energy sales for Virginia are shown as a separate line item in table 7.(2)(b), while demand is treated as part of KU's overall system demand.

7.(5)(b) Historical Information for a Utility Purchasing More Than 50 Percent of Its Energy Needs

This is not applicable to KU.

7.(5)(c) Forecast Information for a Multi-State Integrated Utility System

This applies to KU and Tables 5.(3)-6 and 5.(3)-8 contain the energy and demand forecasts on an annual basis through 2025.

7.(5)(d) Forecast Information for a Utility Purchasing More Than 50 Percent of Its Energy Needs

This is not applicable to KU.

7.(6) Updates of Load Forecasts

Updates will be filed when adopted by KU.

7.(7) Description and Discussion of Data, Assumptions and Judgments, Methods and Models, Treatment of Uncertainty, and Sensitivity Analysis Used in Producing the Forecast

7.(7)(a) Data Sets Used in Producing Forecasts

A first step in the forecast process involves the gathering of national, state, and service territory economic and demographic data that are used to specify models which describe the electric consuming characteristics of KU's and LG&E's customers. To ensure consistency within the planning function, KU and LG&E both obtain this information from Global Insight, a respected and nationally recognized economic consulting firm used by many utilities.

The national outlook for U.S Gross Domestic Product ("GDP"), industrial production and consumer prices are key macro-level variables that establish the broad market environment within which KU operates. Local influences include trends in population, household formation, employment, personal income, and cost of service provision (the 'price' of electricity).

Demographic trends are an important part of the forecasting process. Forecasts of the number of households by county are used to construct a forecast of the number of households by service territory, which is a key driver in the development of the Residential customer forecasts. Residential customers are then used to forecast growth in Commercial customers.

Some of the energy forecast class models are sensitive to retail price changes. The retail price series used in developing the sales forecasts was developed internally.

KU's forecast of residential sales is computer-fed as the product of a sales-per-customer forecast and a forecast of the number of customers. Key inputs to the sales-per-customer forecast include personal income, household size, appliance saturations, appliance efficiencies and electricity prices. Information regarding personal income is provided by Global Insight. Household size, appliance saturations, and appliance efficiencies are based on information from the Energy Information Administration and customer surveys.

For the 2011 IRP, KU's forecast of commercial sales is also the product of a sales-per-customer forecast and a forecast of the number of customers. Key inputs to the sales-per-customer forecast include real gross state product, size of commercial establishment (square footage), efficiencies and saturation of HVAC and other equipment, weather, and electricity prices. Information on real gross state product is provided by IHS Global Insight and appliance efficiencies and saturations are based on information from the Energy Information Administration.

Weather records are also a vital input to electricity sales forecasting. KU receives its weather data from the National Climatic Data Center, a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. For the forecast period (2011-2025), averages of cooling and heating degree days based on the 20-year period ending in 2009 were used in the models. Lexington, Ky., and Bristol, Tenn., weather station data are used in the KU and ODP models, respectively. Degree-days used in the models are all on a 65-degree base.

KU also relies on company-collected survey data as inputs to the forecasting process. Such data enables KU to estimate the mix of residential housing types on the KU system and the approximate saturation level of various appliances.

7.(7)(b) Key Assumptions and Judgments

Key Economic and Demographic Assumptions

To create reliable forecasts of energy consumption, the socio-economic conditions surrounding the forecast period must be accounted for. KU subscribes to IHS Global Insight which is a service that provides estimations of current economic conditions and predictions of future conditions. Global Insight's 2010 Long-Term Macro Forecast and the Population and Household Forecast are both taken into account for the 2011 IRP. Major content of both reports is summarized below. Copies of the economic and demographic forecasts are attached as part of Technical Appendix, 'Supporting Documents,' in Volume II.

- *Trend Scenario*:

  The trend scenario is a projection that assumes no major mishaps between now and 2040. The projection is best described as depicting the mean of all possible paths the economy could follow, absent of any major disruptions such as oil price shocks or major changes in policy.

  The trend scenario between 2011 and 2040 predicts GDP growth slightly below the historical rate for the last thirty years. Personal consumption and government spending are expected to fall slightly as well in comparison to the thirty year historical trend. There is an expected improvement in business investment along with an improvement in the balance of trade with exports growing at a faster rate than imports.

- *Demographics*: The trend scenario provides a demographic prediction which is based on the predictions provided by the Census Bureau. Global Insight predicts slowing

population growth over the next thirty years. Increased life spans for both men and women point to an aging population.

- *Output*: Growth in annual real U.S. Gross Domestic Product was projected to average 2.6 percent over the forecast period.

American Recovery and Reinvestment Act of 2009

The ARRA was introduced by President Obama in February 2009. The provisions in the ARRA relative to energy are intended to increase energy efficiency, research and development of renewable energy and alternative fuels, and research and development of new technology such as smart grid infrastructure. LG&E and KU electricity sales will be impacted primarily by provisions in the act that make efforts to weatherize residential, commercial, and government buildings. The 2011 IRP incorporates the impact of the new weatherization incentives such as tax cuts, funding, loans, and block grants. Further, previous government mandates and general increased awareness of energy efficiency ideas have been incorporated in the 2011 IRP. A more detailed discussion of ARRA and its anticipated impact on electricity sales is included in Section 6.

7.(7)(c) General Methodological Approach

KU's and LG&E's forecasting approach is based on econometric modeling of energy sales by customer class, but also incorporates specific intelligence on the prospective energy requirements of the utility's largest customers. Econometric modeling captures the (observed) statistical relationship between energy consumption – the dependent variable – and one or more independent explanatory variables such as the number of households or the level of economic activity in the service territory. Forecasts of electricity sales are then derived from a projection of the independent variable(s).

This widely-accepted approach can readily accommodate the influences of national, regional and local (service territory) drivers of utility sales. This approach may be applied to forecast customer numbers, energy sales, or use-per-customer. The statistical relationships will vary depending upon the jurisdiction being modeled and the class of service. Within each jurisdiction, the forecast are typically developed by rate class.

The econometric models used to produce the forecast passed two critical tests. First, the explanatory variables of the models were theoretically appropriate and have been widely used in electric utility forecasting. Second, inclusion of those explanatory variables produced statistically-significant results that led to an intuitively reasonable forecast. In other words, the models were proven theoretically and empirically robust to explain the behavior of the KU and LG&E customer and sales data.

With few exceptions, the forecasts are based on a minimum of 10 years of monthly sales history. The modeling of residential and general service ("GS") sales also incorporate elements of end-use forecasting – covering base load, heating and cooling components of sales – which recognize expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

Several large customers for both KU and LG&E are forecast using their recent history and information provided by the customers to KU and LG&E regarding their outlook. These customers are referred to as "Major Accounts." This process allows for market intelligence to be directly incorporated into the sales forecast.

Once complete, the KU and LG&E energy forecasts are converted from a billed to calendar basis and associated with class-specific load profiles to create hourly sales. These are then adjusted for company uses and losses. The resulting estimate of hourly energy requirements is used to generate annual, seasonal, and monthly peak demand forecasts.

KU Sales Forecasts

The KU energy forecast includes three separate jurisdictional groups:

i. Retail sales within Kentucky (Kentucky-retail);

ii. Retail sales within Virginia (Virginia-retail); and

iii. Wholesale sales to 12 municipally-owned utilities in Kentucky.

The distribution of sales by jurisdiction in 2010 was 86 percent Kentucky-retail, 5 percent Virginia-retail, and 9 percent wholesale (FERC jurisdiction).

KU's sales forecast is comprised of 28 forecast models. Each model forecasts the number of customers, use-per-customer, or total sales on a monthly basis and is associated with one or more homogenous rate classes. Because most historical usage data is stored in the company's databases on a billed basis (versus a used or calendar-month basis), sales forecasts are produced initially on a billed basis. Table 7.(7)(c) contains a forecast of billed sales by forecast group (each forecast model is associated with a forecast group). Each forecast group and the associated forecast models are discussed in more detail in the following sections.

Table 7.(7)(c) – KU Billed Sales Forecast by Forecast Group (GWh)

	Residential	Commercial	Industrial	Municipals	Lighting	Virginia Retail	KU Total
2011	6,418	6,066	5,956	2,019	130	917	21,506
2012	6,472	6,194	6,180	2,038	132	924	21,940
2013	6,544	6,334	6,351	2,052	133	930	22,344
2014	6,607	6,435	6,472	2,062	135	935	22,646
2015	6,734	6,589	6,570	2,066	136	943	23,039
2016	6,865	6,725	6,617	2,075	138	953	23,372
2017	6,966	6,829	6,686	2,087	140	960	23,667
2018	7,075	6,950	6,774	2,103	141	967	24,010
2019	7,192	7,083	6,892	2,120	143	974	24,405
2020	7,310	7,221	7,002	2,133	144	983	24,793
2021	7,415	7,319	7,098	2,148	146	990	25,116
2022	7,534	7,455	7,207	2,165	148	998	25,506
2023	7,641	7,559	7,318	2,184	149	1,006	25,858
2024	7,808	7,708	7,433	2,203	151	1,014	26,317
2025	7,941	7,842	7,541	2,218	152	1,024	26,718

KU Residential Forecast

The KU residential forecast includes all customers on the residential service ("RS") and Volunteer fire department ("VFD") rate schedules. Residential sales are forecasted as the product of a use-per-customer forecast and a forecast of the number of customers.

KU Residential Customer Forecasts

The number of KU residential customers was forecasted as a function of the number of households in the KU service territory. Household data by county – history and forecast – was provided by Global Insight.

KU Residential Use-per-Customer Forecast

Average use per customer is forecasted using an SAE model. Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment.

$$\text{Use-per-Customer} = a_1 * \text{XHeat} + a_2 * \text{XCool} + a_3 * \text{XOther}$$

The heating, cooling and other components (the X variables) are based on various input variables including weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and electricity prices. Once the historical profile of these explanatory variables has been established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable, use-per-customer. A discussion of each of these components and the methodology used to develop them is contained in Technical Appendix, *Residential Use-per-Customer Model*, in Volume II.

KU Commercial Forecast Group

The KU commercial forecast group consists of three commercial forecast models: KU GS, KU Power Service ("PS") Secondary, and KU all-electric schools ("AES").

KU General Service

The KU general service forecast includes all customers on the former GS Primary rate (now PS Primary) and is comprised of two separate forecasts: a use-per-customer and a customer forecast. Average use per customer is forecasted using the SAE model. A discussion of the components and the methodology used to develop them is contained in Technical Appendix, Commercial Use-per-Customer Model, in Volume II.

The customer forecast was tied to the Residential customer forecast since, historically, the two have moved together. Based on historical growth relative to the growth rate of Residential customers, the GS customer forecast was allowed to grow at a slightly lower rate than the Residential customer forecast.

KU PS-Secondary

The KU PS-Secondary forecast includes all customers on the former Large Power ("LP") Secondary rate. Sales to PS Secondary customers were modeled as a function of cooling degree days, the Industrial Production Index, real price, and binary variables, which account for oddities in the data. The Time-of-Day ("TOD")-Secondary forecast was based on an allocation of this, which was based on historical usage.

KU All-Electric Schools

The KU all-electric schools forecast includes all customers on the all-electric school rate schedule. KU AES sales were modeled as a function of the number of KU residential customers and weather in all months except for May, June, July, August, October and November (May, October and November because they are shoulder months; June, July, and August because the class is made up of schools).

KU Industrial Forecast Group

The industrial class is unique in the fact that the relatively small number of customers in the class make up a significant portion of the Company's load. Plans to expand or shut-down operations by the larger industrial customers can have a significant impact on the Company's load forecast. For this reason, the company works directly with its largest industrial customers (Major Accounts) wherever possible to develop a five-year forecast for these customers.

Industrial sales are forecasted in total first. The Major Account forecasts are used to adjust the total usage forecast if a significant change is expected (e.g., a Major Account customer is expecting a large expansion project). In theory, since the historical usage data includes the impact of business expansions and shut-downs, most "normal" fluctuations in the Major Account forecasts will be incorporated in the total usage forecast. Therefore, only "exceptional" fluctuations will result in adjustments to the total forecast.

The KU industrial forecast group consists of four forecast models. Each of these models is discussed in more detail in the following sections.

PS Primary

The PS Primary forecast includes all customers on the PS rate schedule that take service at the primary distribution voltage except the GS customers of PS Primary. Sales to PS Primary customers were modeled as a function of cooling degree days, the Industrial Production Index, real price, and binary variables, which account for oddities in the data. The TOD-Primary forecast was based on an allocation of this, which was based on historical usage.

Retail Transmission Service ("RTS")

The RTS forecast includes all retail customers previously on a Transmission-level rate. One of the largest components was the usage by Mine Power customers so a Mine-Power related Industrial Production Index was included as a forecast driver.

Industrial Service

The Industrial Service ("IS") forecast includes one customer on this rate: The North American Stainless Arc Furnace, which is developed based on discussions with that customer.

LTOD Primary

The Large Time-of-Day ("LTOD") Primary forecast includes all customers on the LTOD rate schedule that take service at the primary distribution voltage. Sales to LTOD primary customers are modeled as a function of an industry-weighted Industrial Production Index, households, and weather.

KU Mine Power Forecast Group

The KU mine power forecast group includes three forecast models: PS-Primary, LTOD-Primary, and RTS. With the 2009 Rate Case, all mine power rates were replaced and usage allocated to PS-Primary, LTOD-Primary, and RTS. These are described above.

KU Municipal Forecast Group

The KU municipal forecast group consists of three forecast models: KU transmission municipals, KU primary municipals, and City of Paris. The City of Paris, which takes service at transmission voltages, is forecasted separately because it provides some of its own generation. Each of these models is discussed in more detail in the following sections.

Transmission Municipal

With the exception of the City of Paris, the transmission municipal forecast includes all municipal customers who take service at transmission voltages. Sales to transmission municipal customers were modeled as a function of weather and the number of households in the counties where the transmission municipal customers are located.

Primary Municipal

The primary municipal forecast includes all municipal customers who take service at the primary distribution voltage. Sales to transmission municipal customers were modeled as a function of weather and the number of households in the counties where the transmission municipal customers are located.

City of Paris

Sales to the City of Paris were modeled as a function of weather and the number of households in Bourbon County, Ky. A binary term was also included to adjust for the increase in sales that occurred in February 2003 after KU sold its distribution system within the Paris city limits to the city.

KU Lighting Forecast Group

The KU lighting forecast group consists of two forecast models: KU street lighting and KU private outdoor lighting. Each forecast was produced the same way, as the product of the monthly number of lighting hours, the monthly energy use-per-fixture-per-hour, and a monthly forecasted number of fixtures. For each of these forecasts, the monthly energy use-per-fixture-per-hour was held flat at 2008 levels, and the number of fixtures was forecasted by trending.

ODP Sales Forecasts

The ODP operating unit of Kentucky Utilities serves five counties in southwestern Virginia. As these sales occur in the Virginia jurisdiction, they are modeled separately from other retail sales.

ODP Residential Forecast

The ODP residential forecast includes all customers on the residential service (RS) rate schedule. Residential sales were forecasted as the product of a use-per-customer forecast and a forecast of the number of customers.

ODP Residential Customer Forecasts

The number of ODP residential customers was forecasted as a function of the number of households in the ODP service territory. Household data by county – history and forecast – was provided by Global Insight.

ODP Residential Use-per-Customer Forecast

Average use per customer is forecasted using an SAE model. Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment.

$$\text{Use-per-Customer} = a_1*\text{XHeat} + a_2*\text{XCool} + a_3*\text{XOther}$$

The heating, cooling and other components (the X variables) are based on various input variables like weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and electricity prices. Once these components have been computed, a regression model is specified to forecast use-per-customer as a function of these components. A discussion of each of these components and the methodology used to develop them is contained in Technical Appendix, *Residential Use-per-Customer Model*, in Volume II.

ODP General Service Forecast

The ODP general service forecast includes customers on the general service rate schedule. Average use per customer is forecasted using the SAE model discussed above.

ODP Large Power Forecast

The ODP industrial forecast consists of one forecast model: ODP Large Power. The ODP Large Power forecast includes customers on the large power service rate schedule. Large power sales were forecasted as a function of weather and monthly binary variables.

ODP Schools Forecast

The ODP schools forecast includes all customers on the school service ("SS") rate schedule. Sales to the ODP schools were modeled as a function of the number of residential customers and weather.

ODP Lighting Forecast

The ODP lighting forecast was computed as the product of the number of lighting hours per month, the use-per-fixture-per-hour, and a forecast of the number of lighting fixtures. For each of the classes, the monthly energy use-per-fixture-per-hour was held flat and the number of fixtures was forecasted by trending.

7.(7)(d) Treatment and Assessment of Forecast Uncertainty

Section 5.(6) summarizes the uncertainties that could affect the load forecasts of KU and LG&E. Across forecast cycles, forecast uncertainty is dealt with by review and revision of model specifications to ensure that the relationships between variables are properly quantified and that the structural relationships remain valid.

Within each forecast cycle, there is uncertainty in the forecast values of the independent variables. To address this uncertainty, the company develops high and low forecast scenarios to support sensitivity analysis of the various resource acquisition plans being studied.

7.(7)(e) **Sensitivity Analysis**

For the 2011 IRP, high and low forecast scenarios are prepared based on probabilistic simulation of the historical volatility exhibited by each utility's weather-normalized year-over-year sales trend. In 2015, energy requirements and peak demand are approximately 4 percent higher (roughly 934 GWh and 170 MW) in the high forecast scenario than the base IRP forecast scenario. Compared to the base IRP forecast scenario, energy requirements and peak demand are approximately 4 percent lower in 2015 in the low forecast scenario.

The base IRP, high, and low forecasts of KU's energy sales are presented in Table 7.(7)(e)-1. The associated forecasts of annual peak load are shown in Table 7.(7)(e)-2 and Graph 7.(7)(e)-1.

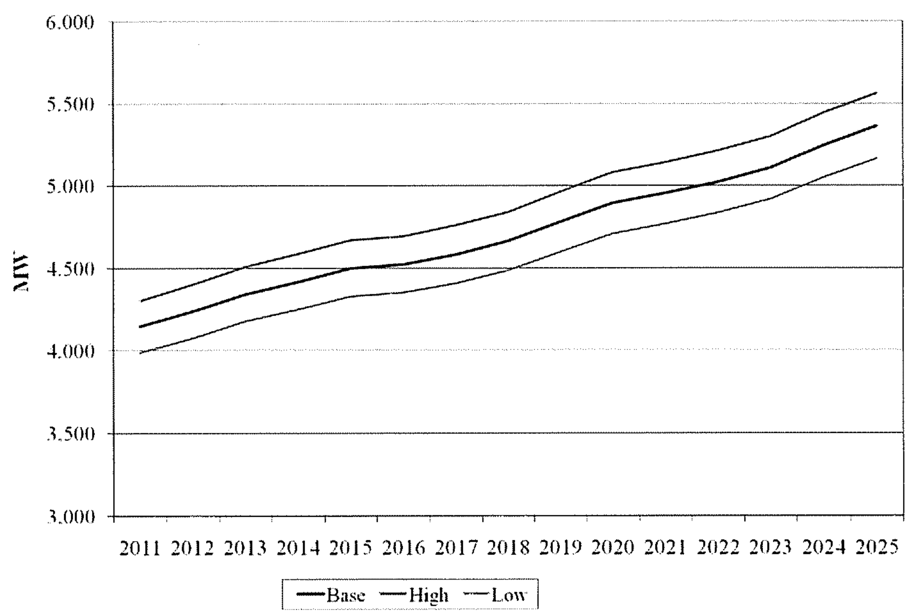
Table 7.(7)(e)-1KU
Base, High, and Low Energy Requirements Forecasts (GWh)

YEAR	Base	High	Low
2011	22,915	23,773	22,057
2012	23,381	24,266	22,497
2013	23,821	24,723	22,918
2014	24,173	25,093	23,253
2015	24,625	25,559	23,692
2016	25,010	25,962	24,059
2017	25,340	26,306	24,373
2018	25,708	26,687	24,728
2019	26,127	27,121	25,133
2020	26,549	27,559	25,539
2021	26,907	27,933	25,880
2022	27,322	28,363	26,282
2023	27,706	28,763	26,649
2024	28,192	29,263	27,120
2025	28,625	29,716	27,535

Table 7.(7)(e)-2
KU Base, High, and Low Peak Demand Forecasts (MW)

YEAR	Base	High	Low
2011	4,146	4,303	3,989
2012	4,237	4,398	4,076
2013	4,341	4,506	4,177
2014	4,417	4,585	4,250
2015	4,497	4,667	4,327
2016	4,522	4,694	4,350
2017	4,584	4,758	4,409
2018	4,663	4,840	4,486
2019	4,780	4,960	4,599
2020	4,895	5,079	4,710
2021	4,953	5,139	4,766
2022	5,022	5,209	4,834
2023	5,109	5,300	4,918
2024	5,244	5,439	5,050
2025	5,361	5,560	5,163

Graph 7.(7)(e)-1
KU Base, High, and Low Peak Demand Forecasts



The base IRP forecast does not explicitly incorporate potential impacts of increasing competition. Integrated resource planning is based on the assumption of an obligation to serve a specifically defined service territory.

KU updates its load forecasts on an annual basis which captures the impact of new appliances, technologies, and regulations as they emerge and penetrate into the energy market. The impacts of existing and future demand-side programs on both energy sales and peak demands are shown in Tables 8.(3)(e)-3, 8.(4)(a)-1, 8.(4)(a)-2 and 8.(4)(b).

7.(7)(f) Research and Development

The 2011 IRP includes two enhancements to its forecasting process. As per the Commission's Responses to the Companies' 2008 IRP, the Companies adopted the SAE model to develop the forecasts for general service customers, which is a component of the commercial sales forecast. The purpose for this change is that it allows the incorporation of changes in commercial end-uses – particularly end-use changes related to energy efficiency and aids in our understanding of the potential impact that the widespread, accelerated adoption of energy efficiency measures could have on electricity sales.

The second change is related to the way the Company develops its hourly demand forecast. In the past, total energy for each utility has been allocated to hours based on an average 10-year load duration curve.

Currently, the company used class-specific load profiles to develop its hourly demand forecasts. This approach enables the Company to better reflect demand-side management programs that impact the load profile of specific classes.

7.(7)(g) Development of End-Use Load and Market Data

In April 2010, KU and LG&E conducted a residential appliance saturation survey. The last such survey was conducted in 2007. The Companies also participate in an Energy Forecaster's Group managed by Itron in which collaborative efforts with other utilities provide the development of regional end-use saturation and efficiency data for the various classes of service.

Louisville Gas and Electric Company

7.(1) Specification of Historical and Forecasted Information Requirements by Class

The data submissions in the following subsections conform to the specifications provided in Section 7.(1) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible.

7.(2) Specification of Historical Information Requirements

The data submissions in the following subsections conform to the specifications provided in Section 7.(2) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible.

7.(2)(a) LG&E Average Customers by Class, 2006-2010

	2006	2007	2008	2009	2010
Total Residential	349,821	352,699	341,312	344,677	349,049
General Service	38,721	39,326	38,959	37,780	36,297
Large Commercial	2,511	2,546	2,567	3,574	5,995
Large Power	398	393	367	411	433
Street Lighting	3,458	3,429	3,346	841	69
Public Authority	2,422	2,310	2,313	3,542	4,025
Total Customers	397,331	400,703	388,864	390,825	395,868

7.(2)(b) LG&E Recorded and Weather-Normalized Annual Energy Sales, Energy Requirements & Sales by Class (GWh)

	2006	2007	2008	2009	2010
SYSTEM BILLED SALES:					
Recorded	12,010	12,669	12,058	11,333	12,277
Weather Normalized	12,132	12,210	12,121	11,562	11,712
SYSTEM USED SALES:					
Recorded	11,965	12,658	12,083	11,405	12,338
Weather Normalized	12,136	12,268	12,038	11,596	11,772
ENERGY REQUIREMENTS:					
Recorded	12,724	13,395	12,802	12,108	13,185
Weather Normalized	12,907	12,983	12,757	12,299	12,619
SALES BY CLASS:					
Residential	4,018	4,486	4,206	4,096	4,592
General Service	1,319	1,428	1,392	1,344	1,461
Large Commercial	2,295	2,409	2,331	2,273	2,332
Large Power	3,068	2,992	2,851	2,412	2,603
Public Authorities	1,205	1,282	1,241	1,221	1,296
Lighting	61	60	62	59	54
TOTAL LG&E SALES	11,965	12,658	12,083	11,405	12,338
SYSTEM LOSSES	744	751	581	524	542
Utility Use	23	24	26	29	2
ENERGY REQUIREMENTS	12,724	13,395	12,802	12,108	13,185

7.(2)(c) LG&E Recorded and Weather-Normalized Peak Demands (MW)

	2006	2007	2008	2009	2010
SUMMER					
Actual	2,713	2,799	2,474	2,479	2,852
Normalized	2,722	2,765	2,549	2,620	2,733
	2005/2006	**2006/2007**	**2007/2008**	**2008/2009**	**2009/2010**
WINTER					
Actual	1,742	1,837	1,881	1,915	1,845
Normalized	1,806	1,868	1,897	1,835	1,828

7.(2)(d) LG&E Energy Sales and Peak Demand for Firm, Contractual Commitment Customers

	2006	2007	2008	2009	2010
Energy Sales (GWh)	11,416	12,388	11,563	11,158	11,867
Coincident Peak Demand (MW)	2,625	2,797	2,450	2,447	2,799

7.(2)(e) LG&E Energy Sales and Peak Demand for Interruptible Customers

	2006	2007	2008	2009	2010
Energy Sales (GWh)	549	270	520	247	471
Coincident Peak Demand (MW)	61	2	24	32	53

7.(2)(f) LG&E Annual Energy Losses (GWh)

	2006	2007	2008	2009	2010
Annual Energy Loss	744	751	581	524	542
Loss Percent of Energy Requirements	6.2%	5.9%	4.8%	4.6%	4.4%

7.(2)(g) Impact of Existing Demand Side Programs

Impacts of the existing demand-side programs on energy and demand requirements are estimated in Table 8.(3)(e)-3.

7.(2)(h) Other Data Illustrating Historical Changes in Load and Load Characteristics

Actual sales and use-per-customer data as reported in tables 7.(2)(a-f) above are calculated using the Company's FERC Form 1 filings as the basis for class segmentation. A historical trend of actual (not weather normalized) average energy use-per-customer by class is shown in Table 7.(2)(h)-1.

Table 7.(2)(h)-1

LG&E Average Annual Use-per-Customer by Class (kWh)

	2006	2007	2008	2009	2010
Residential	11,485	12,720	12,323	11,884	13,156
Small Commercial	34,059	36,312	35,730	35,574	40,251
Large Commercial	914,082	946,190	908,064	635,982	388,991
Industrial	7,707,676	7,613,232	7,768,392	5,868,613	6,011,547
Public Authority	497,393	554,978	536,533	344,720	321,988
Utility Use and Other	17,558	17,622	18,530	70,155	782,609

A history of the percentage share of actual class sales (not weather normalized) to total energy sales is presented in Table 7.(2)(h)-2.

Table 7.(2)(h)-2
LG&E Percentage of Class Sales to Total Energy Sales

	2006	2007	2008	2009	2010
Total Residential	34%	35%	35%	36%	37%
General Service	11%	11%	12%	12%	12%
Large Commercial	19%	19%	19%	20%	19%
Large Power	26%	24%	24%	21%	21%
Public Authority	10%	10%	10%	11%	11%
Lighting	1%	0%	1%	1%	0%
Total Company	100%	100%	100%	100%	100%

LG&E Residential Sales

Changes in actual LG&E residential energy sales are driven by changes in customers and the average use-per-customer. Since 2006, the total number of residential customers has remained flat, while average annual use-per-customer has only increased by 0.2 percent on a weather-normalized basis.

Table 7.(2)(h)-3 shows estimates of LG&E's historical appliance saturation trends.

Table 7.(2)(h)-3
LG&E Electric Appliance Saturations (percent)

APPLIANCE	2003	2007	2010
Refrigerator	100	100	100
Refrigerator (2 or more)	-	30	31
Freezer	40	34	37
Home Computer	62	65	79
Range (Electric)	75	71	70
Microwave Oven	93	91	97
Dishwasher	66	58	74
Clothes Washer	89	87	93
Clothes Dryer (Electric)	76	78	76
Water Heater (Electric)	29	17	28
Dehumidifier	14	15	20
Central Air Conditioning	81	89	88
Electric Heat	25	20	24

LG&E Small Commercial Energy Sales

Weather-normalized sales to the small commercial class have grown since 2006 at an average annual rate of 0.9 percent. This growth has been driven primarily by growth in use-per-customer. On a weather-normalized basis, small commercial use-per-customer has increased by 2.6 percent since 2006. The number of customers has actually declined from 38,721 customers in 2006 to 36,297 in 2010 – an average annual decrease of 1.6 percent.

LG&E Large Commercial Energy Sales

Sales to the large commercial class have decreased at an average annual rate of 1 percent on a weather-normalized basis since 2006. This is due to the reduction in use-per-customer, which has declined at an average annual rate of 20.3 percent since 2006. Clearly, there has been growth in the number of large commercial customers, but there is an important caveat: the 2009 rate case resulted in a reclassification of customers, especially those in the commercial and industrial classes. In addition, the way the customers are counted also has changed. As such, reporting the average annual growth rates can be misleading. For example, the average annual customer growth in the large commercial class from 2006-2010 is 24 percent.

LG&E Industrial Energy Sales

Energy sales to LG&E's industrial class have declined by an annual average of 4% over the 2006-2010 period. The increase in the number of industrial customers over this period was more than offset by a decrease in the weather-normalized average use-per-customer.

7.(3) Specification of Forecast Information Requirements

The information regarding the energy and demand forecasts in the following subsections conform to the specifications outlined in Section 7.(3) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible.

7.(4) LG&E Energy and Demand Forecasts

7.(4)(a) LG&E Forecasted Sales by Class (GWh) and Total Energy Requirements (GWh)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	4,337	4,352	4,386	4,441	4,505	4,577	4,636	4,704	4,782	4,865	4,930	5,005	5,079	5,177	5,244
Small Commercial	1,497	1,524	1,545	1,571	1,599	1,633	1,656	1,683	1,713	1,746	1,773	1,802	1,835	1,871	1,904
Large Commercial	2,388	2,458	2,517	2,559	2,616	2,664	2,713	2,769	2,828	2,890	2,941	3,004	3,055	3,121	3,181
Industrial	2,759	2,781	2,802	2,812	2,813	2,821	2,833	2,850	2,868	2,890	2,906	2,918	2,922	2,929	2,943
Public Authority	1,390	1,422	1,448	1,468	1,493	1,515	1,538	1,564	1,592	1,621	1,646	1,674	1,698	1,727	1,755
Utility Use and Lighting	34	34	33	33	32	32	31	31	31	30	30	30	30	29	29
Total LG&E Calendar Sales	12,406	12,570	12,732	12,884	13,059	13,243	13,408	13,601	13,814	14,042	14,225	14,434	14,620	14,855	15,057
Utility Use and Losses	698	705	719	740	767	796	810	820	832	845	855	874	883	894	908
Requirements	13,104	13,276	13,451	13,624	13,826	14,039	14,218	14,421	14,646	14,887	15,081	15,308	15,503	15,749	15,965

7.(4)(b) LG&E Summer and Winter Peak Demand (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Summer	2,830	2,857	2,894	2,936	2,980	3,007	3,051	3,108	3,189	3,264	3,314	3,370	3,436	3,527	3,596
	10/11	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**18/19**	**19/20**	**20/21**	**21/22**	**22/23**	**23/24**	**24/25**
Winter	1,933	1,934	1,958	1,973	2,002	2,030	2,042	2,077	2,111	2,159	2,217	2,246	2,277	2,324	2,368

7.(4)(c) LG&E Monthly Energy Sales by Class (GWh) and Total Energy Requirements (GWh)

	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	**2011**	380	312	297	255	306	444	537	540	379	262	259	366	4,337
	2012	381	313	298	256	307	445	539	542	380	263	259	368	4,352
Small Commerc	**2011**	118	110	113	108	124	142	151	162	123	118	109	119	1,497
	2012	121	112	115	110	126	144	154	165	126	120	111	121	1,524
Large Commerc	**2011**	188	169	182	184	208	225	228	241	197	195	184	187	2,388
	2012	194	174	188	189	214	231	235	247	203	201	190	193	2,458
Industrial	**2011**	233	209	225	231	225	240	239	251	229	244	218	214	2,759
	2012	235	211	227	232	227	242	241	253	231	246	220	216	2,781
Public Authority	**2011**	109	101	107	99	119	132	130	139	121	118	108	108	1,390
	2012	111	103	109	102	122	134	133	143	123	120	111	111	1,422
Utility Use and	**2011**	3	3	3	3	4	1	2	3	3	3	3	4	34
	2012	3	3	3	3	4	1	2	3	3	3	3	3	34
Total LG&E Calendar	**2011**	1,031	904	927	880	987	1,183	1,288	1,336	1,052	939	881	998	12,406
	2012	1,045	916	940	892	1,001	1,198	1,304	1,353	1,066	953	894	1,011	12,570
Requirements	**2011**	1,082	948	973	926	1,034	1,232	1,342	1,391	1,100	988	925	1,045	12,985
	2012	1,089	954	980	932	1,041	1,241	1,351	1,401	1,107	994	932	1,052	13,073

7.(4)(d) Forecast Impact of Demand-Side Programs

The impacts of existing and future demand-side programs on both energy sales and peak demands are estimated in Table 8.(3)(e)-3. The energy sales forecasts presented in the preceding sections do not include the impacts of those programs. The DSM-related adjustments to summer and winter peak demand and annual energy forecasts were made in Tables 8.(4)(a)-1, 8.(4)(a)-2 and 8.(4)(b) for both LG&E and KU combined. We need to check this statement and the numbers.

7.(5) Historical and Forecast Information for a Multi-State Integrated Utility System

7.(5)(a) Historical Information for a Multi-state Integrated Utility System

This is not applicable to LG&E.

7.(5)(b) Historical Information for a Utility Purchasing More Than 50 Percent of Its Energy Needs

This is not applicable to LG&E.

7.(5)(c) Forecast Information for a Multi-state Integrated Utility System

This is not applicable to LG&E. A Combined Company forecast including ODP is provided in this section of the KU discussion.

7.(5)(d) Forecast Information for a Utility Purchasing More Than 50 Percent of Its Energy Needs

This is not applicable to LG&E.

7.(6) Updates of Load Forecasts

Updates will be filed when adopted by LG&E.

7.(7) Description and Discussion of Data, Assumptions and Judgments, Methods and Models, Treatment of Uncertainty, and Sensitivity Analysis Used in Producing the Forecast

7.(7)(a) Data Sets Used in Producing Forecasts

Please refer to KU section 7.(7)(a).

7.(7)(b) Key Assumptions and Judgments

Key Economic and Demographic Assumptions

To create reliable forecasts of energy consumption, the socio-economic conditions surrounding the forecast period must be accounted for. LG&E subscribes to IHS Global Insight which is a service that provides estimations of current economic conditions and predictions of future conditions. Global Insight's 2010 Long-Term Macro Forecast and the Population and Household Forecast are both taken into account for the 2011 IRP. Major content of both reports is summarized below. Copies of the economic and demographic forecasts are attached as part of the Technical Appendix, 'Supporting Documents,' in Volume II.

- *Trend Scenario*:

  The trend scenario is a projection that assumes no major mishaps between now and 2040. The projection is best described as depicting the mean of all possible paths the economy could follow, absent of any major disruptions such as oil price shocks or major changes in policy.

  The trend scenario between 2011 and 2040 predicts GDP growth slightly below the historical rate for the last thirty years. Personal consumption and government spending are expected to fall slightly as well in comparison to the thirty year historical trend. There is an expected improvement in business investment along with an improvement in the balance of trade with exports growing at a faster rate than imports.

- *Demographics*: The trend scenario provides a demographic prediction which is based on the predictions provided by the Census Bureau. Global Insight predicts slowing population growth over the next thirty years. Increased life spans for both men and women point to an aging population.
- *Output*: Growth in annual real U.S. GDP was projected to average 2.6 percent over the forecast period.

The American Recovery and Reinvestment Act, 2009

The ARRA was introduced by President Obama in February 2009. The provisions in the ARRA relative to energy are intended to increase energy efficiency, research and development of renewable energy and alternative fuels, and research and development of new technology such as smart grid infrastructure. LG&E and KU electricity sales will be impacted primarily by provisions in the act that make efforts to weatherize residential, commercial, and government buildings. The 2011 IRP incorporates the impact of the new weatherization incentives such as tax cuts, funding, loans, and block grants. Further, previous government mandates and general increased awareness of energy efficiency ideas have been incorporated in the 2011 IRP. A more detailed discussion of ARRA and its anticipated impact on electricity sales is included in Section 6.

7.(7)(c) General Methodological Approach

The forecasting methodology for LG&E is discussed in the KU portion of section 7.

LG&E Sales Forecasts

LGE's sales forecast is comprised of 12 forecast models. Each model forecasts sales on a monthly basis and is associated with one or more homogenous rate classes. Because most historical usage data is stored in the company's databases on a billed basis (versus a used or calendar-month basis), sales forecasts are produced initially on a billed basis. Table 7.(7)(c) contains a forecast of billed sales by forecast group (each forecast model is associated with a forecast group). Each forecast group and the associated forecast models are discussed in more detail in the following sections.

Table 7.(7)(c) – LG&E Billed Sales Forecast by Forecast Group

	Residential	Sm Comm	Lg Comm	Industrial	Lighting	LG&E Total
2011	4,336	1,609	3,296	3,106	58	12,406
2012	4,352	1,638	3,392	3,132	57	12,570
2013	4,386	1,660	3,474	3,156	56	12,732
2014	4,441	1,688	3,533	3,167	55	12,884
2015	4,505	1,718	3,612	3,170	54	13,059
2016	4,577	1,755	3,679	3,179	53	13,243
2017	4,636	1,779	3,746	3,194	52	13,408
2018	4,704	1,809	3,824	3,213	52	13,601
2019	4,781	1,841	3,906	3,235	51	13,814
2020	4,864	1,876	3,991	3,260	51	14,042
2021	4,929	1,904	4,063	3,279	50	14,225
2022	5,005	1,936	4,150	3,293	50	14,434
2023	5,079	1,972	4,220	3,299	50	14,620
2024	5,177	2,010	4,312	3,308	49	14,855
2025	5,244	2,045	4,395	3,325	49	15,057

LG&E Residential Forecast

The LG&E residential forecast includes all customers on the RS and VFD rate schedules. Residential sales are forecasted as the product of a use-per-customer forecast and a forecast of the number of customers.

LG&E Residential Customers

The number of LG&E residential customers was forecasted as a function of the number of households in the LG&E service territory. Household data by county – history and forecast – was provided by Global Insight.

LG&E Residential Use-per-Customer Forecast

Average use per customer is forecasted using an SAE model. Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment.

$$\text{Use-per-Customer} = a_1*\text{XHeat} + a_2*\text{XCool} + a_3*\text{XOther}$$

The heating, cooling and other components (the X variables) are based on various input variables including weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and electricity prices. Once the historical profile of these explanatory variables has been established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable, use-per-customer. A discussion of each of these components and the methodology used to develop them is contained in Technical Appendix, *Residential Use-per-Customer Model*, in Volume II.

LG&E Commercial Forecast Group

The LG&E commercial forecast group consists of two commercial forecast models: LG&E small commercial and LG&E large commercial. Each of these models is discussed in more detail below.

LG&E Small Commercial Forecast

The LG&E Small Commercial forecast includes all customers on the General Service ("GS") rate schedule (now IPS Primary and GS Secondary) and is comprised of two separate forecasts: a use-per-customer and a customer forecast. Average use per customer is forecasted using an SAE model. A discussion of the components and the methodology used to develop them is contained in Technical Appendix, Commercial Use-per-Customer Model, in Volume II.

The customer forecast was tied to the Residential customer forecast since, historically, the two have moved together. Based on historical growth relative to the growth rate of Residential customers, the GS customer forecast was allowed to grow at a slightly lower rate than the Residential customer forecast.

LG&E Large Commercial Forecast

The LG&E Large Commercial forecast includes all customers on the Large Commercial ("LC") and Large Commercial Time-of-Day ("LC-TOD") rate schedules. LG&E Large Commercial sales were forecasted in total as a function of weather, number of LG&E households, and the average cost of electric service (the real 'price' of electricity).

LG&E Industrial Forecast Group

The industrial class is unique in the fact that the relatively small number of customers in the class make up a significant portion of the company's load. Plans to expand or shut-down operations by the larger industrial customers can have a significant impact on the company's load forecast. For this reason, the company works directly with its largest industrial customers (Major Accounts) to develop a five-year forecast for these customers.

Industrial sales are forecasted in total first. The Major Account forecasts are used to adjust the total usage forecast if a significant change is expected (e.g., a Major Account customer is expecting a large expansion project). In theory, since the historical usage data includes the impact of business expansions and shut-downs, most "normal" fluctuations in the Major Account forecasts will be incorporated in the total usage forecast. Therefore, only "exceptional" fluctuations will result in adjustments to the total forecast.

The LG&E industrial forecast group consists of two forecast models: LP power and LP-TOD/special contract (under the current rate structure these would be Industrial Power Service ("IPS") Primary and Secondary and Industrial Time-of-Day ("ITOD") Primary and Secondary). A new category was introduced in the 2009 rate case filing. This is known as Retail Transmission Service ("RTS"). Each of these models is discussed in more detail in the following sections.

LP Power

The LP forecast includes all customers on the IPS rate schedule. Monthly sales were modeled as a function of an industry-weighted Industrial Production Index, real per-unit revenue, and weather. The IPS forecast was then allocated to the current rate categories, IPS Primary and IPS Secondary.

LP-TOD/Special Contract

The LP-TOD/Special Contract forecast includes all customers on the Industrial Time-of-Day rate schedule and all special contract customers. Major Account customers that are individually forecasted make up approximately 70% of the total energy usage in this class. Sales to this class were forecasted as a function of a sector-weighted Industrial Production Index, real per-unit revenue, and weather then was adjusted to reflect significant changes in Major Account forecasts. The LP-TOD/Special Contract forecast was then allocated to the current rate categories, ITOD Primary, ITOD Secondary, and RTS.

LG&E Lighting Forecast

The LG&E lighting forecast was computed as the product of the monthly number of lighting hours, the monthly energy use-per-fixture-per-hour, and a monthly forecasted number of fixtures. For each of these forecasts, the monthly energy use-per-fixture-per-hour was held flat at 2008 levels, and the number of fixtures was forecasted using trending models.

7.(7)(d) Treatment and Assessment of Load Forecasting Uncertainty

Please refer to KU Section 7.(7)(d).

7.(7)(e) Sensitivity Analysis

Please refer to KU Section 7.(7)(e) for a summary of the high and low forecast scenarios. The base IRP, high, and low forecasts of LG&E's energy sales are presented in Table 7.(7)(e)-1. The associated forecasts of annual peak load are shown in Table 7.(7)(e)-2 and Graph 7.(7)(e)-1.

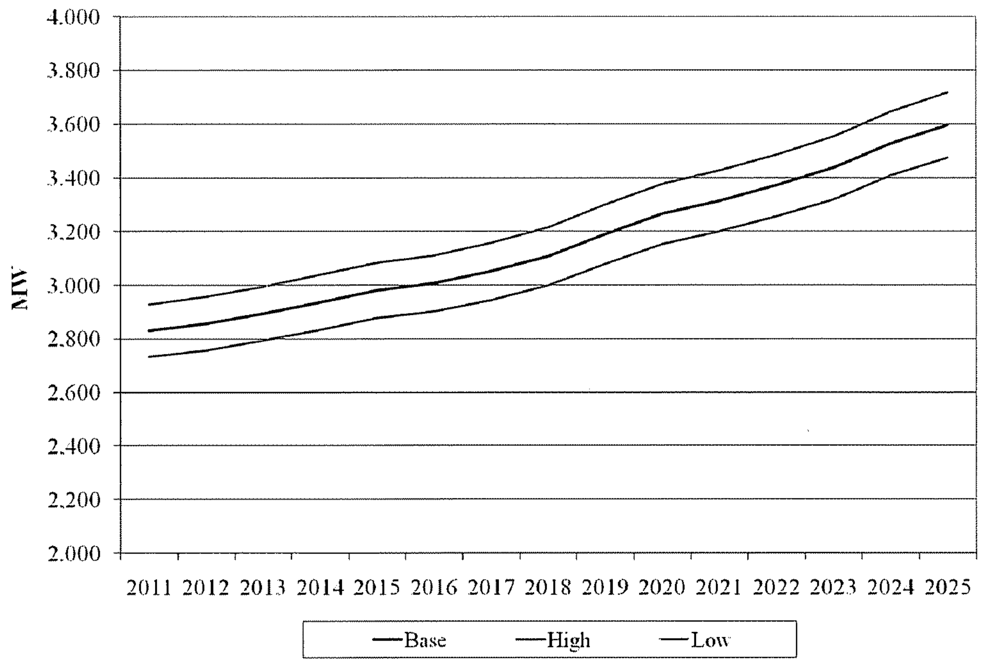
Table 7.(7)(e)-1
LG&E Base, High, and Low Energy Requirements Forecasts (GWh)

YEAR	Base	High	Low
2011	13,104	13,557	12,651
2012	13,276	13,747	12,804
2013	13,451	13,929	12,972
2014	13,624	14,108	13,139
2015	13,826	14,316	13,335
2016	14,039	14,538	13,541
2017	14,218	14,724	13,711
2018	14,421	14,934	13,909
2019	14,646	15,166	14,126
2020	14,887	15,415	14,359
2021	15,081	15,618	14,544
2022	15,308	15,852	14,764
2023	15,503	16,055	14,951
2024	15,749	16,308	15,190
2025	15,965	16,532	15,397

Table 7.(7)(e)-2
LG&E Base, High, and Low Peak Demand Forecasts (MW)

YEAR	Base	High	Low
2011	2,830	2,928	2,733
2012	2,857	2,958	2,756
2013	2,894	2,995	2,793
2014	2,936	3,038	2,834
2015	2,980	3,084	2,877
2016	3,007	3,111	2,902
2017	3,051	3,157	2,945
2018	3,108	3,216	3,000
2019	3,189	3,299	3,079
2020	3,264	3,376	3,153
2021	3,314	3,427	3,200
2022	3,370	3,485	3,256
2023	3,436	3,552	3,320
2024	3,527	3,645	3,408
2025	3,596	3,716	3,475

Graph 7.(7)(e)-1
LG&E Base, High, and Low Peak Demand Forecasts



The latest forecast does not explicitly incorporate potential impacts of increasing competition. Integrated Resource Planning is based on the assumption of an obligation to serve a specifically defined service territory.

LG&E updates its load forecasts on an annual basis which captures the impact of new appliances, technologies, and regulations as they emerge and penetrate into the energy market. The impacts of existing and future demand-side programs on both energy sales and peak demands are shown in Tables 8.(3)(e)-3, 8.(4)(a)-1, 8.(4)(a)-2 and 8.(4)(b).

7.(7)(f) Research and Development Efforts to Improve the Load Forecasting Methods

Please refer to Section 7.(7)(f) under the KU portion of Section 7.

7.(7)(g) Future Efforts to Develop End-Use Load and Market Data

Please refer to Section 7.(7)(g) under the KU portion of Section 7.

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8. RESOURCE ASSESSMENT

8.(1) The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.

The mandate for the Companies' Integrated Resource Plan ("IRP") is to meet future energy requirements within its service territories at the lowest possible cost consistent with reliable supply. As shown year-by-year in Section 8.(4), the plan provides dates for specific resource acquisitions. Changes in assumptions, technology, regulations, market conditions and customer needs are inevitable with the ongoing process of resource planning. This IRP represents one case or snapshot in time within a dynamic process involving assessment of resource options in the context of changing utility needs and new information.

The Companies' resource planning process considers the economics and practicality of available options to meet customer needs. This strategy to furnish electric energy services over the planning horizon in a reliable, economic, and efficient manner while factoring in environmental considerations includes the following processes: 1) determination of a target reserve margin criterion, 2) adequacy assessment of both existing generating units and purchase power agreements, 3) assessment of potential purchase power suppliers, 4) assessment of demand-side options, 5) assessment of supply-side options, and 6) development of an economic plan from all viable resource options.

The Companies commissioned a study to determine an optimal reserve margin criterion. This study indicated that an optimal target reserve margin in the range of 15 to 17 percent would provide an adequate and reliable system to meet customers' demand under a wide range of sensitivities to key assumptions. In the development of the optimal IRP, the Companies targeted a reserve margin of 16 percent. Additional detail on the development of this criterion is contained in the report titled *LG&E and KU 2011 Reserve Margin Study* (April 2011) contained in Volume III, Technical Appendix.

Existing capacity resources are composed of KU- and LG&E-owned generating units and firm purchase power agreements with OVEC. The capacities and operating characteristics of these resources are discussed in more detail in the following sections.

As part of this IRP process, the Companies propose a number of new DSM programs, the evaluation of which is discussed in Section 8.(3)(e) of this report. In addition to these DSM options, the Companies review the technological status, construction considerations, operating costs, and environmental features of various generation plant construction options. After screening many supply-side technologies, nine generation plant construction options were evaluated using Strategist®. Additional detail on the supply-side screening process is contained in the report titled *Analysis of Supply-Side Technology Alternatives* (March 2011) contained in Volume III, Technical Appendix. Strategist® is a proprietary resource planning computer model, developed by Ventyx[1], which integrates the supply-side, demand-side, and environmental compliance alternatives to produce a ranked number of plans that meet the prescribed reliability criteria.

The base case IRP recommends the construction of three combined-cycle combustion turbines, starting with one in 2016, followed by one in 2018 and one in 2025. Also in 2016, it is anticipated that environmental regulations will necessitate the retirement of six coal units. Additionally, there is the implementation of several new DSM programs which combine for an

[1] Ventyx was acquired by power and automation technology group ABB in June 2010.

incremental initiative of 500 MW by the end of 2017. Section 8.(5)(c) summarizes the study in more detail.

A key uncertainty in defining the resource plan is the impact of impending environmental regulations. In the last few years, the EPA has proposed a number of regulations that are expected to take effect in the near future. These regulations are discussed in detail in Sections 8.(5)(b) and 8.(5)(f). The base assumption for this plan is that the most significant impacts to the Companies' generating fleet will begin in 2016 when the MACT/HAPs regulations are anticipated to commence. These regulations will be followed by NAAQS one hour standards for SO_2 and NO_2 in non-attainment areas. As demonstrated in the report titled *2011 Optimal Expansion Plan Analysis* (April 2011) contained in Volume III, Technical Appendix, the least cost plan that complies with these regulations includes retiring the six coal units at the Cane Run, Green River, and Tyrone Stations in 2016.

8.(2) The utility shall describe and discuss all options considered for inclusion in the plan including:

The Companies' strategy to acquire additional resources was developed after a thorough evaluation of both demand-side and supply-side alternatives. This section contains a description and discussion of the options and sensitivities considered during the development of the Companies' optimal IRP.

8.(2)(a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;

Generation

Maintenance Schedules

Maintenance schedules across the Companies' generation fleet are coordinated across the combined KU and LG&E generation system such that the outages will have the least economic impact to the customers and the Companies. The Companies continuously evaluate potential improvements, economic and otherwise, through routine maintenance of their generation fleet.

The Companies continue to plan three-to-four week boiler outages biennially to keep their units running efficiently through the year. All units are scheduled off for one week of maintenance in the offsetting years, with the exception of the Trimble County units which do not have any scheduled maintenance in offsetting years. The target seven-to-eight year cycle for performing major maintenance continues to be successful for the Companies. The Mill Creek and Trimble County units are the only units on eight-year cycles. As inspections reveal potential problems, various boiler and turbine components are repaired or replaced. When equipment enhancements are available, they are analyzed and installed when found to be the prudent option.

The Companies additionally compile outages for shared-ownership units, Trimble County Units 1 and 2. Since the Companies own 75 percent of these units, the Companies are given preference as to when their outages are scheduled. Joint owners Illinois Municipal Electric Agency ("IMEA") and Indiana Municipal Power Agency ("IMPA"), which own 12.12 percent and 12.88 percent ownership respectively, are then informed of any schedule changes.

Efficiency Improvements

Since the Companies' 2008 IRP, the Companies have proceeded with several activities that have maintained or improved generation efficiencies. These have included the latest controls technologies, boiler tube replacements, pulverizer rebuilds, precipitator upgrades, cooling tower rebuilds and generator reliability improvements. A number of other projects have furthered efforts to reduce environmental impact and meet regulatory compliance.

Technologically advanced controls continue to provide the most proven application for improving the efficiency of generating stations. New control technologies allow for tighter control of key operating parameters facilitating optimization of integrated systems not previously available with analog controls. Existing digital controls or distributed control systems ("DCS") have been, or are scheduled to be upgraded on Brown Units 2 and 3, Green River Units 3 and 4, Mill Creek Units 2, 3 and 4, Paddy's Run Unit 13, Trimble County Unit 1 and Ohio Falls Units 5, 6, 7 and 8. These upgrades improve reliability and performance and otherwise replace obsolete versions of these control systems. New digital controls or DCS have been, or are scheduled to be installed on Ghent Unit 2, Cane Run Unit 11 and Paddy's Run Units 11 and 12. Programmable logic controllers, which provide similar efficiency and reliability benefits to DCS, are being implemented at the Haefling and Dix Dam Stations. These new control systems replace less efficient analog relay logic or transistor logic controls.

A fleet-wide performance and reliability program was implemented in 2010, utilizing predictive software monitoring key equipment points and providing alerts for performance inefficiencies and equipment issues. In conjunction with this implementation, data collection and historian systems were expanded in 2009 and 2010, providing for additional efficiency analysis.

Boiler tube failures continue to be the largest contributor to the fleet's equivalent forced outage rate. As native load has increased, so has boiler load demand. Though equipment is aging, units are still required to run at peak capacity. To improve availability, boiler tube studies utilizing software modeling tools and inspections have been conducted using the latest technology to identify boiler sections in need of replacement. All units across the fleet have scheduled boiler outages to replace boiler tube sections. These efforts continue to ensure maximum boiler availability and reliability.

Changes in coal supply and coal burner modifications to reduce gaseous emissions have negatively impacted boiler slagging and precipitator performance. A coal test burn program has been implemented along with advanced modeling using fuel performance software, to improve boiler efficiency and reduce boiler slagging. To ensure compliance with the current particulate emission standards, partial precipitator rebuilds have taken place on E.W. Brown Units 1 and 2 and Trimble County Unit 1. Improved and modernized precipitator controls have been installed on E.W. Brown Unit 1 and Cane Run Units 4-6. These modifications have reduced incidences of output restriction necessitated by opacity emission compliance.

Other efficiency improvements and unit derate improvements at various plants in the fleet included:

- Pulverizer rebuilds on all units
- Cooling tower rebuilds on Ghent Units 2, 3 and 4, using polymer technology and fill design to ensure availability and improve heat transfer

- Air compressor replacement on numerous units, improving operating efficiency and lowering the dew point which reduces the number of instrument related unit derates
- Gas path outlet duct and expansion joint replacement on numerous units in which sections of the boiler outlet ductwork and expansion joints are replaced improving boiler performance issues and reducing pluggage in the unit scrubber modules
- Fuel delivery and handling equipment refurbishments on numerous units
- Air heater basket replacements on numerous units, improving air flow and boiler efficiency
- Condensate equipment:
    - The condensate water treatment facility at the Mill Creek station was replaced with a higher production facility utilizing reverse osmosis technology, reducing chemical treatments, increasing efficiency and reducing derates.
    - Heat exchangers were replaced and condensers were retubed on numerous units, improving heat transfer efficiency and improving boiler chemistry.
    - A fleet wide eddy current testing program was performed on the condenser tubes to reduce the number of forced derates.
- At the Cane Run station, medium voltage switchgear was upgraded, replacing equipment that experienced multiple failures that resulted in unit outages and derates.

Other capital projects since the 2008 IRP included environmental projects, including the start-up of new FGD systems at the Ghent and E.W. Brown stations, catalyst replacement in selective catalytic reduction ("SCR") systems, mercury monitor installation, new or expanded plant landfills and ash ponds, and replacement of analyzing equipment. By reducing the amount of SO_2 emissions, the new FGD installations reduce the Companies' risk associated with SO_2 emission regulation. SCR catalyst must be maintained to deliver high removal efficiencies of NO_x in order to prevent carry-over of unreacted ammonia to the air heaters. Ammonia in the air heaters reacts to form ammonium bi-sulfates ("ABS") which builds up in the air heater, increasing pressure dip and induced draft fan loading. Excessive buildup of ABS will result in forced unit outages to allow for air heater washing. Annual catalyst testing and new catalyst installation allow for maintained NO_x removal efficiency and low ammonia slip. Appendix K style continuous emission mercury monitors were installed throughout the fleet to measure the actual mercury emissions, thereby improving the accuracy of reporting mercury emissions compared to the previous method of calculating the mercury emissions values.

Landfill and ash pond expansion projects have continued at E.W. Brown, Ghent, Mill Creek and Trimble County stations. A combination of coal combustion product sales and ash containment expansions will extend the onsite storage capability of the ponds and landfills, helping to control overall generation costs. All units in the fleet are continuing to analyze and replace stack emissions monitoring equipment to continue to maintain a high level of accuracy for the stack emissions data.

A fleet-wide effort to review and analyze manufacturer reporting, equipment monitoring, and engineering programs has resulted in various projects and initiatives. Beginning in 2010, multiple sets of critical generator stator bars were purchased to address the manufacturer's recommended maintenance practices. Mill Creek Unit 3's generator stator will have a "re-wedge" performed in spring 2011. During all major generator outages involving General

Electric ("GE") machines, a "top tooth" inspection on the rotor will be performed using various techniques to address GE TIL 1292 which has identified potential long term cracking in certain machine designs. As part of our ongoing turbine inspection and maintenance program, all turbine inlet snout rings will be inspected and refurbished during turbine overhauls. A critical transformer maintenance and risk mitigation program is in development which will address both short and long term maintenance practices and strategic risk mitigation.

The hydroelectric units at Ohio Falls and Dix Dam have benefited from significant overhaul and upgrade efforts. Ongoing overhaul work at Ohio Falls includes new water flow wicket gates, new impellers, generator rewinds, and new unit controls and instrumentation. A detailed description of the Ohio Falls project follows in the next subsection titled *Rehabilitation of Ohio Falls*. At the Dix Dam Station, replacement of the Johnson valve on Dix Dam Unit 2 is scheduled for 2011 which will complete the plan to mitigate the potential for complete failure of this vintage valve[2]. KU has also undertaken a project to overhaul the Dix Dam Units to improve their availability and efficiency. The overhauls include rewinding the generators, refurbishing turbine sections including the wicket gates and runners, and installing state of the art controls with automated equipment status indication. Each overhaul will result in a capacity increase on each unit from 8 to 10 MW, for a total increase of 6 MW, at the current lake level target range. The overhaul on Unit 3 was completed in 2009 with final testing completed in February 2010. Unit 2 is expected to be completed in 2011 and Unit 1 is expected to be completed in 2012.

Rehabilitation of Ohio Falls

The Ohio Falls Station was granted a 40-year operational license by the FERC effective November 11, 2005. The license stipulates that the Companies would complete the upgrades to

[2] Johnson valve replacements on Dix Dam Units 1 and 3 occurred in 2005 and 2007, respectively.

the project within nine years from the effective date of the new license. The rehabilitation project for the Ohio Falls Station was divided into three phases over a number of years, beginning in 2001. With the first two phases of the project complete, only the third and final phase continues. Phase 3 entails the rehabilitation of the turbine/generator units. Generally, Phase 3 of the rehabilitation takes place during the low water season in the latter six months of a given year. Rehabilitation was completed on Unit 7 in October 2006 and on Unit 6 in January 2008. Rehabilitation work on Unit 5 is scheduled to begin in 2011 and the remaining five units are planned to be completed by the end of 2014.

Rehabilitation of each unit will result in a nameplate capacity rating increase from 10 MW to 12.58 MW. However, the Ohio Falls Station is a run-of-river facility that is subject to actual river flow. Total rehabilitation of all eight units will result in increasing the expected summer net capacity output of the station to 64 MW from the 48 MW capacity output prior to performing the rehabilitation.

In addition to the rehabilitation efforts at the Ohio Falls and Dix Dam Stations, the Companies continue to monitor potential hydro opportunities. However, sites for additional conventional hydro facilities on the Ohio River are limited.

Transmission

The primary purpose of the Companies' transmission system is to reliably transmit electrical energy from Company-owned generating sources to native load customers. The transmission system is designed to deliver Company-owned generator output and emergency generation to meet projected customer demands and to provide contracted long-term firm transmission services. Interconnections have been established with other utilities to increase the reliability of the transmission system and to provide potential access to other economic and emergency generating sources for native load customers. The transmission system is planned to withstand simultaneous forced outages of a generator and a transmission facility during peak conditions.

The Companies routinely identify transmission construction projects and upgrades required to maintain the adequacy of its transmission system to meet projected customer demands. In compliance with the FERC Standards of Conduct, these projects covering the Companies' transmission system is covered in its entirety in *Transmission Information* of Volume III, Technical Appendix of this Plan.

Distribution

Distribution Planning standards and guidelines are developed and maintained by the Distribution System Analysis and Planning Group, a part of Distribution Operations' Asset Management Organization. Common practices, guidelines and standards are in use for both the LG&E and KU service areas.

The distribution system has been enhanced over the past three years through the construction of new substations and distribution lines as well as the expansion and/or enhancement of existing substations and distribution lines to meet growing customer loads and to improve service reliability and quality.

Peak substation transformer loads are monitored annually and load forecasts are developed for a ten-year planning period. Loading data and other system information is used to develop a joint ten-year plan for major capacity enhancements necessary to address load growth and improve system performance. In addition to planned major enhancements, LG&E and KU distribution personnel continue to plan and construct (on a daily basis) an appropriate level of conductors, distribution transformers and other equipment necessary to satisfy the normal service needs of new and existing customers.

From 2008 to 2010, LG&E and KU have had projects to install, upgrade or replace an average of nineteen distribution substation transformers per year throughout the combined LG&E and KU service territories to serve new customers, improve service reliability, and/or mitigate the effects on customers due to major equipment failures. A total of fourteen such projects were completed in 2010. This trend is expected to continue and thirty-six distribution substations have already been targeted for review in 2011 thru 2013 for capacity enhancements.

KU and LG&E continue to design, build and operate the distribution system in a cost-effective, efficient manner. Substation and distribution transformers are purchased using Total Ownership Cost criteria that minimize the first cost and the cost of losses over the life of the asset. Distribution transformer efficiencies are now DOE compliant or better. KU and LG&E have continued to install capacitors on the distribution system to provide more efficient use of transmission, substation and distribution facilities. KU and LG&E plan to continue to design for near unity power factor at the substation bus where capacitor installations on the distribution system are reasonable and feasible.

8.(2)(b) Conservation and load management or other demand-side programs not already in place;

The Companies are currently seeking approval for additional DSM programs that will further increase energy and demand savings. These programs include the Smart Energy Profile Program, Residential Incentives Program, and a Residential Refrigerator Removal Program.

8.(2)(c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and

The economics and practicality of supply-side options were carefully examined to develop an IRP to meet the Companies' energy requirements. Various supply-side options, including both mature and emerging technologies, were evaluated as part of the integrated resource planning process. Table 8.(2)(c) contains unit data for each supply-side option reviewed. Additional detail on this process is contained in the report titled *Analysis of Supply-Side Technology Alternatives* (March 2011) contained in Volume III, Technical Appendix.

LG&E owns a 75 percent undivided interest in Trimble County Unit 1. The remaining 25 percent of the unit is owned by IMEA and IMPA. IMEA purchased a 12.12 percent undivided interest in the unit on February 28, 1991 and IMPA purchased a 12.88 percent undivided interest on February 1, 1993. Each of these companies had Right of First Refusal on ownership for Trimble County Unit 2. Both opted to exercise their option to purchase an interest in Trimble County Unit 2. As a result, the Companies own 75 percent of the unit (60.75 percent KU and 14.25 percent LG&E); IMPA and IMEA own the remaining 25 percent (12.88 percent and 12.12 percent, respectively).

Table 8.(2)(c)
Generating Technology Options Summary
2010 $

Unit Type	Fuel Type	Size MW	Cost $/kW	F O&M ($/kW-yr.)	V O&M ($/MWh)	Heat Rate (Btu/kWh)	Comm Avail.	Tech. Rating
Combustion Turbine								
Simple Cycle GE LM6000 CT	Gas	43	[redacted]	$20	$24	9,214	Yes	Mature
Simple Cycle GE LM6000 CT	Gas	84	[redacted]	$15	$25	11,740	Yes	Mature
Simple Cycle GE LM6000 CT	Gas	206	[redacted]	$5	$15	9,848	Yes	Mature
Combined Cycle GE 7EA CT	Gas	109	[redacted]	$36	$6	8,093	Yes	Mature
Combined Cycle 1x1 7F-Class	Gas	314	[redacted]	$11	$5	6,777	Yes	Mature
Combined Cycle 1x1 G-Class CT	Gas	406	[redacted]	$8	$4	6,725	Yes	Mature
Combined Cycle 2x1 7F-Class CT	Gas	629	[redacted]	$6	$4	6,768	Yes	Mature
Combined Cycle 3x1 7F-Class CT	Gas	943	[redacted]	$5	$4	6,753	Yes	Mature
Combined Cycle Siemens 5000F CT	Gas	251	[redacted]	$17	$5	7,085	Yes	Mature
Humid Air Turbine Cycle CT	Gas	366	[redacted]	$9	$5	10,355	No	Developmental
Kalina Cycle CC CT	Gas	282	[redacted]	$16	$2	6,348	No	Developmental
Cheng Cycle CT	Gas	140	[redacted]	$15	$5	7,270	No	Developmental
Peaking Microturbine	Gas	0.03	[redacted]	$157	$35	14,561	Yes	Commercial
Baseload Microturbine	Gas	0.03	[redacted]	$158	$7	14,561	Yes	Commercial
Pulverized Coal								
Subcritical Pulverized Coal - 256 MW	Coal	256	[redacted]	$74	$3	9,287	Yes	Mature
Subcritical Pulverized Coal - 512 MW	Coal	512	[redacted]	$62	$3	9,160	Yes	Mature
Circulating Fluidized Bed - 2x 250 MW	Coal	500	[redacted]	$53	$6	10,155	Yes	Mature
Supercritical Pulverized Coal - 565 MW	Coal	565	[redacted]	$54	$4	9,066	Yes	Mature
Supercritical Pulverized Coal-800 MW	Coal	800	[redacted]	$46	$4	9,036	Yes	Mature
Pressurized Fluid. Bed Combust. Coal								
Pressurized Fluidized Bed Combustion	Coal	290	[redacted]	$73	$3	9,048	No	Developmental
Integrated Gasification Combined Cycle								
1x1 IGCC	Coal Gasification	307	[redacted]	$55	$3	8,456	Yes	Commercial
2x1 IGCC	Coal Gasification	640	[redacted]	$79	$1	8,889	Yes	Commercial
Coal Technologies with Carbon Capture & Sequestration								
Subcritical Pulverized Coal - 502 MW - CCS	Coal	502	[redacted]	$70	$5	12,906	No	Developmental
Circulating Fluidized Bed - CC	Coal	572	[redacted]	$91	$7	14,010	No	Developmental
Supercritical Pulverized Coal - 565 MW - CCS	Coal	565	[redacted]	$75	$8	12,800	No	Developmental
Supercritical Pulverized Coal - 800 MW - CCS	Coal	800	[redacted]	$63	$8	9,036	No	Developmental
1x1 IGCC - CCS	Coal	270	[redacted]	$69	$3	10,069	No	Developmental
2x1 IGCC - CC	Coal	556	[redacted]	$87	$1	10,463	No	Developmental
Energy Storage								
Pumped Hydro Energy Storage	Charging Only	350	[redacted]	$6	$6	0	Yes	Mature
Advanced Battery Energy Storage	Charging Only	100	[redacted]	$1	$15	0	No	Developmental
Compressed Air Energy Storage	Gas and Charging	350	[redacted]	$31	$2	3,970	Yes	Commercial
Renewable Energy								
Wind Energy Conversion	No Fuel	200	[redacted]	$11	$7	0	Yes	Commercial
Solar Photovoltaic								
Solar Photovoltaic	No Fuel	25.0	[redacted]	$30	$0	0	Yes	Commercial
Solar Thermal								
Solar Thermal, Parabolic Trough	No Fuel	100	[redacted]	$64	$1	0	Yes	Commercial
Solar Thermal, Power Tower w Storage	No Fuel	100	[redacted]	$64	$1	0	Yes	Commercial
Solar Thermal, Parabolic Dish	No Fuel	1	[redacted]	$64	$0	0	Yes	Commercial
Solar Thermal, Central Receiver	No Fuel	50	[redacted]	$127	$1	0	No	Commercial
Solar Thermal, Solar Chimney	No Fuel	50	[redacted]	$74	$0	0	No	Developmental
Waste Energy								
MSW Mass Burn	MSW	7	[redacted]	$590	$40	19,160	Yes	Commercial
RDF Stoker-Fired	RDF	7	[redacted]	$490	$12	16,558	Yes	Commercial
Landfill Gas IC Engine	Landfill Gas	5	[redacted]	$61	$16	9,500	Yes	Mature
TDF Multi-Fuel CFB (10% Co-fire)	10% TDF / 90% Coal	50	[redacted]	$104	$3	10,669	Yes	Commercial
Sewage Sludge & Anaerobic Digestion	No Fuel	0.09	[redacted]	$228	$0	9,900	Yes	Commercial
Bio Mass								
Bio Mass (Co-Fire)	10% Renew / 90% Coal	514	[redacted]	$67	$1	9,251	Yes	Mature
Wood-Fired CFBC	Biomass	100	[redacted]	$87	$2	11,570	Yes	Commercial
Co-Fired CFBC	10% Renew / 90% Coal	566	[redacted]	$92	$12	14,120	Yes	Commercial
Wood Fired Stoker Plant	Biomass	50	[redacted]	$131	$4	13,325	Yes	Commercial
Hydroelectric Power								
Hydroelectric - New - 30 MW	No Fuel	30	[redacted]	$42	$0	0	Yes	Mature
Hydroelectric - 50 MW Bulb Unit	No Fuel	50	[redacted]	$15	$0	0	Yes	Mature
Hydroelectric - 14 MW Kaplans Units	No Fuel	28	[redacted]	$9	$0	0	Yes	Mature
Hydroelectric - 25 MW Bulb Units	No Fuel	50	[redacted]	$12	$0	0	Yes	Mature
Hydroelectric - 50 MW Kaplan Unit	No Fuel	50	[redacted]	$12	$0	0	Yes	Mature
Hydroelectric - 50 MW Propeller Unit	No Fuel	50	[redacted]	$11	$0	0	Yes	Mature
Other								
Molten Carbonate Fuel Cell	Gas	20	[redacted]	$8	$8	5,460	Yes	Commercial
Solid Oxide Fuel Cell	Gas	25	[redacted]	$14	$0	6,370	Yes	Commercial
Spark Ignition Engine	Gas	5	[redacted]	$181	$0	9,492	Yes	Mature

Capacity figures are based on annual average

8.(2)(d) Assessment of non-utility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other non-utility sources.

The Companies have used an RFP process to obtain offers from the electric market for specific power needs. The Companies distribute its RFP to qualified parties in the market ensuring broad market coverage and the opportunity to discover least cost options for power supply. This process serves the Companies and the native load well.

On December 1, 2010, the Companies issued an RFP for firm generating capacity and energy in order to evaluate alternatives for meeting existing and pending EPA regulations and to meet future load growth. Eighteen parties responded with offers to this RFP and the Companies are currently evaluating the various proposals.

The Companies also consider short-term economy purchases on a non-firm basis. Further details of this are covered under the subsection titled *Short-Term Power Purchases* of Section 5.(4) of this IRP.

8.(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multi-state integrated system shall submit the following information for its operations within Kentucky and for the multi-state utility system of which it is a part. A utility which purchases 50 percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs.

8.(3)(a) A map of existing and planned generating facilities, transmission facilities with a voltage rating of 69 kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.

In compliance with the FERC Standards of Conduct, the portion of this IRP covering the Companies' transmission system was written separately from the bulk of this document and is covered in *Transmission Information* of Volume III, Technical Appendix of this plan. Hence, the map of the Companies' existing transmission system (which includes the location of the generating facilities), a description of the interconnections (including a table), and a discussion of the transfer capabilities are also provided in *Transmission Information* of Volume III, Technical Appendix of this Plan.

8.(3)(b) A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the 15 years of the forecast period, including for each facility:

1. **Plant name;**
2. **Unit number(s);**
3. **Existing or proposed location;**
4. **Status (existing, planned, under construction, etc.);**
5. **Actual or projected commercial operation date;**
6. **Type of facility;**
7. **Net dependable capability, summer and winter;**
8. **Entitlement if jointly owned or unit purchase;**
9. **Primary and secondary fuel types, by unit;**
10. **Fuel storage capacity;**
11. **Scheduled upgrades, deratings, and retirement dates;**
12. **Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the 15 forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars.**
    a. **Capacity and availability factors;**
    b. **Anticipated annual average heat rate;**
    c. **Costs of fuel(s) per millions of British thermal units (MMBtu);**
    d. **Estimate of capital costs for planned units (total and per kilowatt of rated capacity);**
    e. **Variable and fixed operating and maintenance costs;**
    f. **Capital and operating and maintenance cost escalation factors;**
    g. **Projected average variable and total electricity production costs (in cents per kilowatt-hour).**

The requested information can be found in the tables on the following pages.

Table 8.(3)(b)

KU and LG&E Existing and Planned Electric Generation Facilities

1	2	3	4	5	6	7		8		9	10	11
Plant Name	Unit No.	Location in Kentucky	Status	Operation Date	Facility Type	Net Capability (MW) 2011/12 Winter	Net Capability (MW) 2011 Summer	Entitlement KU	Entitlement LGE	Fuel Type	Fuel Storage Cap/SO. Content	Scheduled Upgrades Derates, Retirements
Cane Run	4	Louisville	Existing	1962	Steam	155	155		100%	Coal (Rail)	350,000 Tons (6.0# SO2)	Assumed to retire 2016
	5			1966		168	168					
	6			1969		240	240					
	11			1968	Turbine	14	14			Gas / Oil	50,000 Gals	None
Dix Dam	1-3	Burgin	Existing	1925	Hydro	28	26	100%		Water	None	4 MW upgrade 2011-2012
E. W. Brown Coal	1	Burgin	Existing	1957	Steam	107	106	100%		Coal (Rail)	360,000 Tons (6# SO2)	Baghouse Derate 2014
	2			1963		168	166					Baghouse Derate 2015
	3			1971		415	411					SCR Derate 2012 Baghouse Derate 2016
E.W. Brown-ABB 11N2	5			2001	Turbine	131	122	47%	53%	Gas	2,200,000 Gals	None
E.W. Brown-ABB GT24	6			1999		163	146	62%	38%	Gas / Oil		
	7			1999		163	146					
E.W. Brown-ABB 11N2	8			1995		129	121	100%				
	9			1994		129	121					
	10			1995		129	121					
	11			1996		129	121					
Ghent	1	Ghent	Existing	1974	Steam	486	493	100%		Coal (Barge)	1,300,000 Tons (6# SO2)	Baghouse Derate 2016
	2			1977		480	490					Baghouse Derate 2016
	3			1981		485	454					Baghouse Derate 2015
	4			1984		495	487					Baghouse Derate 2015
Green River	3	Central City	Existing	1954	Steam	71	68	100%		Coal	150,000 Tons (4.5# SO2)	Assumed to retire 2016
	4			1959		102	95					
Haefling	1	Lexington	Existing	1970	Turbine	14	12	100%		Gas / Oil	130,000 Gals	None
	2			1970		14	12					
	3			1970		14	12					
Mill Creek	1	Louisville	Existing	1972	Steam	303	303		100%	Coal (Barge & Rail)	1,000,000 Tons (6# SO2)	Baghouse Derate 2014
	2			1974		299	301					Baghouse Derate 2013
	3			1978		397	391					Baghouse Derate 2015
	4			1982		492	477					Baghouse Derate 2014
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	Run of River (35/52)			100%	Water	None	12 MW upgrade 2011-2014
Paddy's Run	11	Louisville	Existing	1968	Turbine	13	12		100%	Gas	None	None
	12			1968		28	23					
Paddy's Run- Siem/West V84.3a	13			2001		175	158	47%	53%			
Tyrone	3	Versailles	Existing	1953	Steam	73	71	100%		Coal (Truck)	30,000 Tons (1.4# SO2)	Assumed to retire 2016
Trimble County Coal (75%)	1	Near Bedford	Existing	1990	Steam	515 (386)	511 (383)	0%	75%	Coal (Barge)	1,000,000 Tons (6.0# SO2)	Baghouse Derate 2015
	2			2011		761 (571)	732 (549)	61%	14%		150,000 Tons (0.6# SO2)	None
Trimble County-GE7FA	5			2002	Turbine	180	160	71%	29%	Gas	None	None
	6			2002		180	160					
	7			2004		180	160	63%	37%			
	8			2004		180	160					
	9			2004		180	160					
	10			2004		180	160					
Zorn	1	Louisville	Existing	1969	Turbine	16	14		100%	Gas	None	None
Future Units												
3x1 Combined Cycle	1	Unknown	Proposed	2016	Turbine	1,009	907	Unknown		Gas	None	None
3x1 Combined Cycle	2			2018		1,009	907					
3x1 Combined Cycle	3			2025		1,009	907					

CONFIDENTIAL INFORMATION

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 1

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	46.5	13.6	20.9	23.7	19.4	17.9	40.4	44.9	46.1	52.3	48.5	44.0	54.8	58.9	58.4	63.8
a	**Availability Factor (%)**	85.3	88.3	86.5	90.0	77.7	90.0	86.5	90.0	86.5	90.0	86.5	77.7	86.5	90.0	86.5	90.0
b	**Average Heat Rate (Btu/kWh)**	11,072	11,034	11,022	10,883	10,869	10,916	10,829	10,828	10,816	10,817	10,815	10,821	10,804	10,786	10,795	10,785
c	**Cost of Fuel ($/MBTU)**	3.47	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 2

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	52.2	18.5	31.0	30.8	37.9	34.0	45.4	50.4	53.2	59.2	57.4	62.0	67.5	63.8	68.5	73.7
	Availability Factor (%)	84.9	84.7	90.0	86.5	90.0	84.7	77.7	90.0	86.5	90.0	86.5	90.0	86.5	77.7	90.0	86.5
b	**Average Heat Rate (Btu/kWh)**	10,282	10,147	10,206	10,124	10,139	10,145	10,131	10,140	10,139	10,144	10,128	10,129	10,130	10,116	10,134	10,130
c	**Cost of Fuel ($/MBTU)**	3.42	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 3

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	48.7	44.1	40.8	46.1	46.0	47.2	55.4	59.9	59.1	55.0	60.5	65.4	65.4	68.9	67.3	71.9
	Availability Factor (%)	79.3	87.4	78.4	90.9	87.4	90.9	85.6	90.9	87.4	78.4	87.4	90.9	87.4	90.9	87.4	90.9
b	**Average Heat Rate (Btu/kWh)**	11,090	10,725	10,707	10,720	10,697	10,706	10,583	10,580	10,563	10,543	10,552	10,535	10,512	10,499	10,496	10,483
c	**Cost of Fuel ($/MBTU)**	3.39	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 5

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	0.8	1.4	1.1	0.8	1.3	1.1	1.2	1.4	0.9	0.5	0.5	0.7	0.9	1.0	1.2	0.6
a	**Availability Factor (%)**	81.5	87.6	84.2	87.6	84.2	87.6	87.6	87.6	87.6	87.6	74.1	87.6	87.6	87.6	87.6	87.6
b	**Average Heat Rate (Btu/kWh)**	17,404	17,661	17,839	16,783	17,042	16,533	16,852	16,604	17,617	17,188	16,634	16,462	16,565	16,125	16,109	15,964
c	**Cost of Fuel ($/MBTU)**	5.10	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 6

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	3.6	2.0	1.4	0.9	1.7	1.3	1.3	1.5	1.5	0.5	0.5	0.8	1.0	1.1	1.5	1.0
a	**Availability Factor (%)**	55.8	91.4	91.4	91.4	89.6	91.4	91.4	78.8	91.4	91.4	89.6	93.2	93.2	93.2	93.2	93.2
b	**Average Heat Rate (Btu/kWh)**	13,104	13,871	13,942	13,831	13,829	13,780	13,842	13,778	13,691	13,864	13,838	13,800	13,837	13,755	13,787	13,553
c	**Cost of Fuel ($/MBTU)**	5.56	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 7

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	3.5	1.6	1.2	0.8	1.8	1.2	1.3	1.5	1.5	0.5	0.5	0.7	0.8	1.0	1.3	0.9
	Availability Factor (%)	96.0	89.6	91.4	91.4	89.6	91.4	89.6	91.4	78.8	91.4	91.4	93.2	93.2	93.2	93.2	93.2
b	**Average Heat Rate (Btu/kWh)**	13,710	13,921	13,986	13,842	13,926	13,797	13,843	13,814	13,822	13,889	13,821	13,799	13,831	13,759	13,775	13,614
c	**Cost of Fuel ($/MBTU)**	5.50	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 8

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	0.8	1.1	0.9	0.9	1.4	1.2	1.2	1.4	0.9	0.5	0.5	0.7	0.9	1.0	1.3	0.7
a	**Availability Factor (%)**	99.7	92.2	90.4	88.6	92.2	88.6	92.2	92.2	92.2	88.6	92.2	92.2	92.2	92.2	92.2	92.2
b	**Average Heat Rate (Btu/kWh)**	17,650	15,095	15,189	15,104	15,062	14,991	15,013	14,955	15,006	15,105	15,021	15,003	14,972	14,898	14,821	14,793
c	**Cost of Fuel ($/MBTU)**	6.23	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 9

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	0.6	0.8	0.7	0.7	1.1	1.0	1.0	1.2	0.7	0.4	0.5	0.6	0.7	0.9	1.1	0.6
	Availability Factor (%)	99.3	88.6	90.4	78.0	92.2	88.6	92.2	92.2	92.2	88.6	92.2	92.2	92.2	92.2	92.2	92.2
b	**Average Heat Rate (Btu/kWh)**	19,671	14,924	15,025	14,954	14,905	14,844	14,884	14,777	14,731	14,962	14,869	14,794	14,770	14,683	14,617	14,475
c	**Cost of Fuel ($/MBTU)**	5.31	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 10

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	0.5	0.8	0.6	0.6	0.9	0.8	0.8	1.0	0.5	0.3	0.4	0.5	0.6	0.7	0.9	0.5
	Availability Factor (%)	93.3	92.2	88.6	92.2	78.0	92.2	88.6	92.2	92.2	88.6	92.2	92.2	92.2	92.2	92.2	92.2
b	**Average Heat Rate (Btu/kWh)**	20,872	14,749	14,840	14,803	14,718	14,680	14,685	14,612	14,476	14,798	14,710	14,642	14,618	14,536	14,472	14,289
c	**Cost of Fuel ($/MBTU)**	5.43	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 11

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	0.9	0.6	0.5	0.5	0.8	0.7	0.7	0.8	0.4	0.3	0.3	0.4	0.5	0.6	0.8	0.4
a	**Availability Factor (%)**	90.8	88.6	88.6	92.2	92.2	92.2	78.0	92.2	92.2	92.2	92.2	92.2	92.2	92.2	92.2	92.2
b	**Average Heat Rate (Btu/kWh)**	16,941	14,474	14,594	14,591	14,481	14,468	14,476	14,401	14,177	14,576	14,507	14,436	14,412	14,337	14,280	14,041
c	**Cost of Fuel ($/MBTU)**	5.40	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Cane Run 4

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	68.3	32.3	27.6	22.6	34.0	33.1										
	Availability Factor (%)	82.7	77.7	91.5	85.9	91.2	85.9		•								
b	**Average Heat Rate (Btu/kWh)**	11,288	12,458	12,550	12,512	12,494	12,480										
c	**Cost of Fuel ($/MBTU)**	2.10	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

CONFIDENTIAL INFORMATION

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Cane Run 5

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	75.5	43.4	36.1	32.4	42.9	37.1										
a	**Availability Factor (%)**	93.7	86.5	91.5	85.9	91.2	77.2										
b	**Average Heat Rate (Btu/kWh)**	10,640	11,861	11,924	11,926	11,858	11,878										
c	**Cost of Fuel ($/MBTU)**	2.08	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Cane Run 6

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	Capacity Factor (%)	58.1	36.7	24.8	22.7	28.9	30.6										
	Availability Factor (%)	72.5	92.7	87.1	92.1	86.8	92.1										
b	Average Heat Rate (Btu/kWh)	10,704	11,648	11,745	11,724	11,638	11,641										
c	Cost of Fuel ($/MBTU)	2.08	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

CONFIDENTIAL INFORMATION

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Cane Run 11

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.1
	Availability Factor (%)	99.7	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	**Average Heat Rate (Btu/kWh)**	26,794	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117	16,117
c	**Cost of Fuel ($/MBTU)**	13.45	[redacted]														

Notes: 2010 numbers are actuals.

Capacity Factor (%) based on net summer unit rating. Unit Runs less than 1% capacity factor.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Ghent 1

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	79.2	65.7	70.7	72.9	69.7	86.8	69.5	75.9	72.9	78.6	76.6	67.2	81.4	76.5	82.5	79.8
	Availability Factor (%)	87.0	89.7	87.9	91.5	77.2	91.5	86.1	91.5	86.1	91.5	87.9	78.9	91.5	87.9	91.5	87.9
b	**Average Heat Rate (Btu/kWh)**	10,459	11,012	10,997	10,999	10,973	10,959	10,994	10,988	10,986	10,985	10,982	10,995	10,978	10,985	10,982	10,979
c	**Cost of Fuel ($/MBTU)**	2.22	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

CONFIDENTIAL INFORMATION

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Ghent 2

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	75.5	90.0	76.0	90.1	86.6	88.3	84.9	88.3	90.1	75.9	90.1	86.6	90.1	86.6	90.1	86.6
	Availability Factor (%)	94.5	91.5	77.2	91.5	87.9	89.7	86.1	89.7	91.5	77.2	91.5	87.9	91.5	87.9	91.5	87.9
b	**Average Heat Rate (Btu/kWh)**	10,502	10,145	10,098	10,092	10,093	10,092	10,094	10,092	10,092	10,098	10,092	10,093	10,092	10,093	10,092	10,093
c	**Cost of Fuel ($/MBTU)**	2.22	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

CONFIDENTIAL INFORMATION

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Ghent 3

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	81.6	47.0	59.4	57.8	70.4	64.1	62.5	55.5	67.8	66.3	69.1	68.8	71.3	69.0	68.1	75.9
	Availability Factor (%)	90.6	77.2	87.9	87.9	91.5	84.3	91.5	78.9	91.5	86.1	91.5	87.9	91.5	87.9	78.9	91.5
b	**Average Heat Rate (Btu/kWh)**	10,935	11,305	11,308	11,305	11,303	11,293	11,323	11,302	11,313	11,310	11,311	11,303	11,307	11,302	11,289	11,300
c	**Cost of Fuel ($/MBTU)**	2.24	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Ghent 4

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	61.8	80.4	85.3	89.3	83.1	78.0	79.4	83.2	78.9	84.7	82.6	86.2	74.9	86.2	84.1	87.9
	Availability Factor (%)	75.4	91.5	87.9	91.5	84.3	78.9	87.9	91.5	86.1	91.5	87.9	91.5	78.9	91.5	87.9	91.5
b	**Average Heat Rate (Btu/kWh)**	11,014	10,128	10,266	10,270	10,274	10,277	10,251	10,263	10,257	10,260	10,267	10,276	10,266	10,279	10,279	10,278
c	**Cost of Fuel ($/MBTU)**	2.30	[redacted]														

Notes: 2010 numbers are actuals.

Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Green River 3

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	Capacity Factor (%)	91.3	18.1	16.5	14.0	18.6	17.9										
	Availability Factor (%)	80.0	88.7	76.5	88.7	83.4	88.7										
b	Average Heat Rate (Btu/kWh)	11,950	12,893	13,039	13,046	12,998	12,997										
c	Cost of Fuel ($/MBTU)	2.69	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Green River 4

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	41.5	36.5	44.7	38.6	51.9	59.3										
	Availability Factor (%)	91.5	83.4	88.7	76.5	88.7	83.4										
b	**Average Heat Rate (Btu/kWh)**	11,089	10,950	10,904	10,814	10,870	10,839										
c	**Cost of Fuel ($/MBTU)**	2.71	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Haefling 1,2,3

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	Capacity Factor (%)	0.2	0.2	0.1	0.1	0.2	0.2	0.2	0.3	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.1
	Availability Factor (%)	96.3	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	Average Heat Rate (Btu/kWh)	32,075	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	Cost of Fuel ($/MBTU)	7.56	[redacted]														

Notes: 2010 numbers are actuals.

Capacity Factor (%) based on net summer unit rating. Unit Runs less than 1% capacity factor.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Mill Creek 1

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	75.7	91.0	76.9	87.9	83.6	87.5	85.4	90.6	85.5	90.7	78.4	90.9	85.3	91.0	85.6	91.0
	Availability Factor (%)	84.3	91.5	78.9	91.5	86.1	91.5	86.1	91.5	86.1	91.5	78.9	91.5	86.1	91.5	86.1	91.5
b	**Average Heat Rate (Btu/kWh)**	10,683	10,339	10,314	10,311	10,318	10,313	10,334	10,335	10,335	10,336	10,331	10,338	10,333	10,339	10,336	10,339
c	**Cost of Fuel ($/MBTU)**	1.87	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Mill Creek 2

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	79.7	78.0	86.4	77.5	81.3	79.0	89.9	84.3	90.2	77.7	90.4	85.0	90.3	85.0	90.5	85.2
	Availability Factor (%)	88.7	78.9	91.5	86.1	91.5	86.1	91.5	86.1	91.5	78.9	91.5	86.1	91.5	86.1	91.5	86.1
b	**Average Heat Rate (Btu/kWh)**	10,845	10,518	10,482	10,468	10,437	10,456	10,514	10,509	10,514	10,515	10,516	10,516	10,519	10,516	10,517	10,518
c	**Cost of Fuel ($/MBTU)**	1.87	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Mill Creek 3

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	85.1	77.7	82.9	74.3	84.7	69.5	89.7	84.5	90.4	77.8	90.6	85.5	90.6	85.6	91.0	86.0
a	Availability Factor (%)	89.3	78.9	91.5	86.1	91.5	86.1	91.5	86.1	91.5	78.9	91.5	86.1	91.5	86.1	91.5	86.1
b	Average Heat Rate (Btu/kWh)	10,738	10,222	10,196	10,200	10,196	10,196	10,214	10,218	10,216	10,225	10,218	10,222	10,218	10,223	10,220	10,225
c	Cost of Fuel ($/MBTU)	1.87	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Mill Creek 4

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	80.1	88.6	79.3	83.7	59.7	76.1	84.4	90.4	85.3	90.9	85.8	91.0	78.9	91.3	86.0	91.5
a	**Availability Factor (%)**	83.2	89.7	86.1	91.5	78.9	91.5	86.1	91.5	86.1	91.5	86.1	91.5	78.9	91.5	86.1	91.5
b	**Average Heat Rate (Btu/kWh)**	10,520	10,336	10,293	10,292	10,283	10,276	10,317	10,325	10,325	10,328	10,328	10,328	10,331	10,330	10,329	10,334
c	**Cost of Fuel ($/MBTU)**	1.89	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Paddy's Run 11

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.1
	Availability Factor (%)	95.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	**Average Heat Rate (Btu/kWh)**	117,927	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479
c	**Cost of Fuel ($/MBTU)**	42.64	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating. Unit Runs less than 1% capacity factor.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Paddy's Run 12

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	Capacity Factor (%)	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.1
	Availability Factor (%)	77.7	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	Average Heat Rate (Btu/kWh)	117,927	17,005	17,005	17,005	17,005	17,005	17,005	17,005	17,005	17,005	17,005	17,005	17,005	17,005	17,005	17,005
c	Cost of Fuel ($/MBTU)	42.64	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating. Unit Runs less than 1% capacity factor.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Paddy's Run 13

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	1.1	8.5	13.1	9.3	13.6	12.0	12.6	13.0	4.2	6.0	5.7	6.5	8.2	7.7	9.7	5.5
	Availability Factor (%)	72.9	65.0	89.6	89.6	89.6	89.6	89.6	89.6	63.2	89.6	89.6	91.3	91.3	91.3	91.3	91.3
b	**Average Heat Rate (Btu/kWh)**	11,037	10,720	10,724	10,717	10,717	10,714	10,715	10,711	10,713	10,722	10,714	10,713	10,714	10,704	10,704	10,709
c	**Cost of Fuel ($/MBTU)**	8.99	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County 1 (75%)

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	79.3	81.5	95.1	87.6	95.1	87.4	95.1	80.0	95.1	87.4	95.1	87.5	95.1	87.4	95.1	80.2
	Availability Factor (%)	87.4	84.1	95.1	87.8	95.1	87.8	95.1	80.5	95.1	87.8	95.1	87.8	95.1	87.8	95.1	80.5
b	**Average Heat Rate (Btu/kWh)**	10,611	10,127	10,119	10,119	10,119	10,120	10,120	10,121	10,121	10,120	10,119	10,120	10,119	10,120	10,119	10,119
c	**Cost of Fuel ($/MBTU)**	2.22	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County 2 (75%)

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	Capacity Factor (%)		84.0	85.4	93.3	86.1	93.3	86.1	93.3	78.9	93.3	86.1	93.3	86.1	93.3	86.1	93.3
	Availability Factor (%)		84.0	85.4	93.3	86.1	93.3	86.1	93.3	78.9	93.3	86.1	93.3	86.1	93.3	86.1	93.3
b	Average Heat Rate (Btu/kWh)		8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 5

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	9.2	8.1	11.0	8.6	13.2	10.9	14.1	14.3	12.7	6.7	6.4	7.6	9.0	9.4	10.8	7.8
a	**Availability Factor (%)**	91.0	80.8	95.5	95.5	95.5	95.5	80.8	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5
b	**Average Heat Rate (Btu/kWh)**	11,323	12,571	12,864	12,881	12,714	12,892	11,273	11,403	11,320	11,526	11,533	11,466	11,475	11,402	11,431	11,251
c	**Cost of Fuel ($/MBTU)**	6.07	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 6

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	7.2	10.3	8.8	7.1	11.2	9.1	12.4	11.7	10.5	4.8	4.7	5.6	6.8	7.1	8.3	6.2
a	**Availability Factor (%)**	65.7	95.5	95.5	95.5	95.5	95.5	95.5	80.8	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5
b	**Average Heat Rate (Btu/kWh)**	11,548	12,310	12,677	12,697	12,574	12,717	11,309	11,391	11,290	11,526	11,521	11,461	11,470	11,395	11,421	11,284
c	**Cost of Fuel ($/MBTU)**	5.88	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 7

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	Capacity Factor (%)	9.0	8.4	7.1	5.6	9.5	7.4	10.3	9.0	8.1	3.9	3.9	4.7	5.8	6.0	7.2	5.0
	Availability Factor (%)	97.6	80.8	95.5	95.5	95.5	95.5	95.5	80.8	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5
b	Average Heat Rate (Btu/kWh)	12,543	12,128	12,486	12,520	12,437	12,524	11,333	11,435	11,326	11,534	11,527	11,467	11,477	11,400	11,424	11,234
c	Cost of Fuel ($/MBTU)	6.20	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 8

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	7.0	7.1	4.1	4.4	7.6	5.8	7.5	7.6	4.7	3.0	3.1	3.8	4.6	5.0	5.8	4.0
	Availability Factor (%)	95.5	95.5	80.8	95.5	95.5	95.5	95.5	95.5	80.8	95.5	95.5	95.5	95.5	95.5	95.5	95.5
b	**Average Heat Rate (Btu/kWh)**	11,548	12,021	12,261	12,239	12,190	12,265	11,272	11,398	11,228	11,533	11,528	11,455	11,464	11,388	11,406	11,205
c	**Cost of Fuel ($/MBTU)**	6.11	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 9

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	8.9	5.7	4.7	3.5	6.2	4.7	5.7	6.2	5.1	2.2	2.3	2.9	3.5	3.9	4.6	3.3
a	**Availability Factor (%)**	97.4	95.5	80.8	95.5	95.5	95.5	95.5	95.5	80.8	95.5	95.5	95.5	95.5	95.5	95.5	95.5
b	**Average Heat Rate (Btu/kWh)**	11,474	11,797	12,095	11,969	11,957	12,000	11,331	11,375	11,261	11,445	11,429	11,370	11,386	11,307	11,328	11,156
c	**Cost of Fuel ($/MBTU)**	6.25	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 10

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	7.4	4.4	3.7	2.7	4.9	3.7	4.3	4.8	4.0	1.6	1.8	2.3	2.8	3.1	3.7	2.6
	Availability Factor (%)	96.7	95.5	95.5	80.8	95.5	95.5	95.5	95.5	95.5	80.8	95.5	95.5	95.5	95.5	95.5	95.5
b	**Average Heat Rate (Btu/kWh)**	11,372	11,611	11,773	11,632	11,715	11,700	11,251	11,284	11,227	11,344	11,345	11,299	11,319	11,240	11,260	11,100
c	**Cost of Fuel ($/MBTU)**	6.09	[redacted]														

Notes: 2010 numbers are actuals.

Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Tyrone 3

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	22.1	8.7	9.1	7.8	11.9	10.9										
	Availability Factor (%)	94.8	91.3	91.3	91.3	91.3	91.3										
b	**Average Heat Rate (Btu/kWh)**	13,477	12,930	12,911	12,709	12,787	12,675										
c	**Cost of Fuel ($/MBTU)**	3.76	[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Zorn 1

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Capacity Factor (%)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.1
a	Availability Factor (%)	99.7	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	Average Heat Rate (Btu/kWh)	48,720	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676	18,676
c	Cost of Fuel ($/MBTU)	5.04	[redacted]														

Notes: 2010 numbers are actuals.

Capacity Factor (%) based on net summer unit rating. Unit Runs less than 1% capacity factor.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

3x1 Combined Cycle 1

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**							19.3	20.3	18.7	17.3	16.3	18.8	21.1	21.4	23.6	21.2
	Availability Factor (%)							94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1
b	**Average Heat Rate (Btu/kWh)**							6,753	6,753	6,753	6,753	6,753	6,753	6,753	6,753	6,753	6,753
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 2010 numbers are actuals.

Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

3x1 Combined Cycle 2

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**									9.8	23.8	22.7	25.4	27.9	28.1	30.6	25.9
	Availability Factor (%)									94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1
b	**Average Heat Rate (Btu/kWh)**									6,753	6,753	6,753	6,753	6,753	6,753	6,753	6,753
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

3x1 Combined Cycle 3

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**																14.4
	Availability Factor (%)								•								94.1
b	**Average Heat Rate (Btu/kWh)**																6,753
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Dix Dam 1,2,3

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	17.1	24.7	24.6	24.7	24.7	24.7	24.6	24.7	24.7	24.7	24.6	24.7	24.7	24.7	24.6	24.7
b	**Average Heat Rate (Btu/kWh)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none
c	**Cost of Fuel ($/MBTU)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Ohio Falls 1-8

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
a	**Capacity Factor (%)**	51.9	55.2	51.7	52.6	52.0	56.2	56.1	56.2	56.2	56.2	56.1	56.2	56.2	56.2	56.1	56.2
b	**Average Heat Rate (Btu/kWh)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none
c	**Cost of Fuel ($/MBTU)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none

Notes: 2010 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12(d),(f)

Kentucky Utilities Company / Louisville Gas & Electric Company

Capital Costs and Escalation Factors
(In 2010 Dollars)

	Supercritical Coal	3x1 Combined Cycle	2x1 Combined Cycle	1x1 Combined Cycle	Simple Cycle CT	Wind Turbine	Landfill Gas Engine	Hydro Bulb Unit
Capital Costs ($/kW)	[redacted]							
Total Capital Costs ($x1000)								
Capital Escalation Factor (%)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Variable O&M Escalation Factor (%)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Fixed O&M Escalation Factor (%)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0

Notes:
Capital Cost $/kW based on summer rating.
Fixed and variable escalation factors also apply to existing units.

Table 8.(3)(b)12(e)

Kentucky Utilities Company / Louisville Gas & Electric Company

Variable and Fixed Operating and Maintenance Costs ($000)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing units	303,694	[redacted]														
3x1 Combined Cycle 1		[redacted]														
3x1 Combined Cycle 2		[redacted]														
3x1 Combined Cycle 3		[redacted]														

Notes:
2010 numbers are actuals.
An annual gas reservation expense is in included in the Fixed O&M of CTs and Combined Cycle units.
O&M data for existing units is shown in total.

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Table 8.(3)(b)12(g) - 1

Kentucky Utilities Company / Louisville Gas & Electric Company

Total Electricity Production Costs (cents/kWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing units*	3.41	[redacted]														
3x1 Combined Cycle 1		[redacted]														
3x1 Combined Cycle 2		[redacted]														
3x1 Combined Cycle 3		[redacted]														

Notes:
2010 numbers are actuals.
An annual gas reservation expense is in included in the Fixed O&M of CTs and Combined Cycle units.
O&M data for existing units is shown in total.

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Table 8.(3)(b)12(g) - 2

Kentucky Utilities Company / Louisville Gas & Electric Company

Average Variable Production Costs (cents/kWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing units*	2.51	[redacted]														
3x1 Combined Cycle 1																
3x1 Combined Cycle 2																
3x1 Combined Cycle 3																

Notes:
2010 numbers are actuals.
An annual gas reservation expense is in included in the Fixed O&M of CTs and Combined Cycle units.
O&M data for existing units is shown in total.

8.(3)(c) Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the 15 forecast years of the plan.

The requested information can be found in the Table 8.(3)(c) on the following page.

Table 8.(3)(c)

Kentucky Utilities Company / Louisville Gas & Electric Company

Description of Transactions for Purchases, Sales or Exchanges of Electricity

Purchases (GWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OMU	580	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OVEC	1,214	677	821	666	794	863	1,058	930	1,012	1,072	991	1,000	1,045	944	906	918
Other	652	1	1	1	1	1	2	3	1	0	1	1	2	3	5	1

Sales (GWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OMU	1,212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OTHER	538	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Note: 2010 numbers are actuals.

8.(3)(d) Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other non-utility sources available for purchase by the utility during the base year or during any of the 15 forecast years of the plan.

The requested information can be found in Table 8.(3)(d) on the following page.

Table 8.(3)(d)

Kentucky Utilities Company / Louisville Gas & Electric Company

Non-Utility Sources of Generation

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Generating Capacity (MW)	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Energy (GWh)	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

8.(3)(e) For each existing and new conservation and load management or other demand-side programs included in the plan:

8.(3)(e)(1) Targeted classes and end-uses;

Residential Customer Class

Residential Load Management / Demand Conservation Program (Enhanced Program)

This program cycles residential central air conditioning units, water heaters, and residential pool pumps of both LG&E and KU customers. It is designed to provide customers with an incentive to allow the Companies to interrupt service to their central air conditioners, water heaters, and/or pool pumps at peak demand periods when the Companies need additional resources to meet customer demand. The program enhancement being sought in Case No. 2011-00134 will allow for increased customer incentives in order to encourage greater customer enrollment in the program.

Residential Conservation / Home Energy Performance Program (Enhanced Program)

This program targets customers who own or occupy single-family homes, apartments or condominiums. It is designed to provide customers with an on-site home energy audit that will provide opportunities for improved energy efficiency. The program enhancement being sought for approval in Case No. 2011-00134 is to include incentives to implement the energy retrofit measures recommended through the energy audit process allowing for greater energy and demand reductions.

Residential Low Income Weatherization Program (Enhanced Program)

This program is designed to reduce the energy bills of customers who are less fortunate by weatherizing their homes. This program is available to "Low Income Home Energy

Assistance Program" (LIHEAP) eligible customers. The program enhancement requested in Case No. 2011-00134 will allow for additional weatherization measures to the low income customer segment and for an increase in the number of customers served over the program plan.

Residential Smart Energy Profile (New Program)

The objective of the Smart Energy Profile Program is to provide approximately 50% of residential customers of LG&E/KU with a customized report based on individual household energy consumption over the first four years of the program. These reports are benchmarked against similar properties by size, type, number of residents and location. Additional tips and EE programming recommendations will be provided to educate and encourage behavior change.

Residential Incentives Program (New Program)

The Residential Incentives Program is designed to provide direct financial incentives to encourage customers to purchase various Energy Star appliances, HVAC equipment, or window films that meet certain requirements.

Residential Refrigerator Removal Program (New Program)

The Refrigerator Removal Program is designed to provide removal and recycling of inefficient secondary refrigerators and freezers from LG&E and KU households. The removal of these inefficient units will reduce consumption and demand.

Residential High Efficiency Lighting Program (Approved and Unchanged)

The Residential High Efficiency Lighting Program promotes an increased use of ENERGY STAR® rated CFLs within the residential sector of LG&E and KU electric consumers. The Residential High Efficiency Lighting Program distributes compact fluorescent bulbs through direct-mail delivery, customer walk-in centers and retailer coupons.

Residential New Construction Program (Approved and Unchanged)

The Residential New Construction Program is designed to reduce residential energy usage and facilitate market transformation by creating a shift in builders' new home construction to include energy-efficient construction practices.

Residential HVAC Diagnostics and Tune Up Program (Approved and Unchanged)

The Residential HVAC Diagnostic and Tune-up Program targets customers with HVAC system performance issues.

Commercial Customer Class

Commercial Load Management / Demand Conservation Program (Enhanced Program)

This program cycles commercial central air conditioning units and water heaters of both LG&E and KU customers. It is designed to provide customers with an incentive to allow the Companies to interrupt service to their central air conditioners and water heaters at peak demand periods when the Companies need additional resources to meet customer demand. The program enhancement being sought in Case No. 2011-00134 will allow for increased customer incentives to encourage greater customer enrollment in the program.

Commercial Conservation / Commercial Incentives Program (Enhanced Program)

This program is offered to all commercial class customers. The objective is to identify energy efficiency opportunities for commercial class customers and assist them in the implementation of these identified energy efficiency opportunities. The program enhancement being sought in an upcoming case is the result of customers requesting a custom rebate option to allow for additional opportunity to capture savings beyond the original prescriptive equipment list. This rebate will encourage greater customer enrollment in the program.

Commercial HVAC Diagnostics and Tune Up Program (Approved and Unchanged)

The Commercial HVAC Diagnostic and Tune-up Program targets customers with HVAC system performance issues.

8.(3)(e)(2) Expected duration of the program;

Programs the KPSC approved in Case No. 2007-00319 and not included in the pending DSM proceeding will remain unchanged and operate through December 31, 2014. Upon approval of proposed program enhancements and new programming, the Companies' DSM/EE portfolio of programs will extend operations for an additional seven years from KPSC approval.

8.(3)(e)(3) Projected energy changes by season, and summer and winter peak demand changes;

Load changes for the existing rate programs are currently captured in the load forecast. Table 8.(3)(e)(3) summarizes the annual energy impact and the summer and winter peak demand of the LG&E interruptible rate and the future programs.

Table 8.(3)(e)(3)
Louisville Gas and Electric Company / Kentucky Utilities Company/
Demand Side Management Energy and Demand Impacts

DSM Energy Reduction (GWh)	Status	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential High Efficiency Lighting	Existing	201.8	250.6	299.5	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3	348.3
Residential New Construction	Existing	6.9	9.0	11.4	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
Residential HVAC Tune Up	Existing	1.9	3.0	4.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Commercial HVAC Tune Up	Existing	2.0	4.2	6.4	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Customer Education & Public Information	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dealer Referral Network	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Responsive Pricing (RRP)	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Development & Administration	Enhanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Conservation (HEPP)	Enhanced	15.5	20.7	25.9	31.0	36.2	41.4	46.5	51.7	56.8	62.0	67.2	72.3	77.5	82.7	87.8	93.0
Residential Load Management	Enhanced	5.9	9.6	12.8	16.0	18.7	21.4	24.1	26.7	29.4	32.1	34.7	37.4	40.1	42.7	45.4	48.1
Commercial Load Management	Enhanced	0.2	0.4	0.6	0.7	0.8	0.9	1.0	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0
Residential Low Income Weatherization	Enhanced	20.5	23.3	26.1	28.9	31.7	34.5	37.3	46.5	55.7	64.9	74.1	83.3	92.5	101.8	111.0	120.2
Commercial Conservation/Rebates	Enhanced	93.8	150.8	208.8	266.8	324.8	382.7	440.7	495.7	550.7	605.7	660.7	715.7	770.6	825.6	880.6	935.6
Smart Energy Profile	New	29.3	57.0	57.0	104.4	104.4	104.4	104.4	106.5	106.5	106.5	106.5	106.5	106.5	106.5	106.5	106.5
Residential Refrigerator Removal	New	3.0	9.0	16.5	24.0	31.4	38.9	46.4	53.9	61.4	68.9	76.4	83.9	91.4	98.9	106.4	113.9
Residential Incentives	New	8.8	20.0	36.9	53.8	70.7	87.6	104.6	120.8	137.1	153.4	169.7	186.0	202.3	218.6	234.9	251.2
Total Annual Energy Reduction	All	389.7	557.6	705.9	901.8	994.9	1,088.1	1,181.2	1,279.1	1,375.1	1,471.0	1,566.9	1,662.9	1,758.8	1,854.7	1,950.7	2,046.6

Table 8.(3)(e)(3) Continued

DSM Summer Peak Demand Reduction (MW)	Status	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential High Efficiency Lighting	Existing	14.2	17.5	20.8	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1
Residential New Construction	Existing	2.8	3.5	4.2	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Residential HVAC Tune Up	Existing	0.9	1.3	1.8	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Commercial HVAC Tune Up	Existing	0.5	1.0	1.5	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Customer Education & Public Information	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dealer Referral Network	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Responsive Pricing (RRP)	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Development & Administration	Enhanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Conservation (HEPP)	Enhanced	2.2	3.6	5.1	6.5	8.0	9.4	10.9	12.2	13.5	14.8	16.1	17.4	18.8	20.1	21.4	22.7
Residential Load Management	Enhanced	157.3	171.6	183.9	196.2	206.5	216.7	227.0	237.2	247.5	257.7	268.0	278.2	288.5	298.7	309.0	319.2
Commercial Load Management	Enhanced	5.9	6.7	7.6	8.5	9.1	9.6	10.2	10.8	11.4	12.0	12.5	13.1	13.7	14.3	14.9	15.4
Residential Low Income Weatherization	Enhanced	1.0	1.3	1.6	1.8	2.1	2.4	2.7	3.6	4.5	5.4	6.3	7.3	8.2	9.1	10.0	10.9
Commercial Conservation/Rebates	Enhanced	26.5	47.9	69.7	91.6	113.4	135.2	157.0	177.7	198.4	219.1	239.8	260.4	281.1	301.8	322.5	343.2
Smart Energy Profile	New	5.6	10.9	10.9	19.9	19.9	19.9	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Residential Refrigerator Removal	New	0.4	1.2	2.1	3.1	4.1	5.0	6.0	6.9	7.7	8.6	9.4	10.3	11.1	12.0	12.8	13.7
Residential Incentives	New	2.5	5.7	11.0	16.3	21.7	27.0	32.3	35.3	38.4	41.4	44.5	47.5	50.5	53.6	56.6	59.7
Total Annual Demand Reduction	All	219.6	272.3	320.4	377.6	418.2	458.9	499.5	537.6	575.2	612.9	650.5	688.2	725.8	763.4	801.1	838.7

Table 8.(3)(e)(3) Continued

DSM Winter Peak Demand Reduction (MW)	Status	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential High Efficiency Lighting	Existing	27.8	35.8	43.2	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1
Residential New Construction	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential HVAC Tune Up	Existing	0.1	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Commercial HVAC Tune Up	Existing	0.2	0.4	0.7	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Customer Education & Public Information	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dealer Referral Network	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Responsive Pricing (RRP)	Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Development & Administration	Enhanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Conservation (HEPP)	Enhanced	0.9	1.4	2.1	3.0	3.9	4.7	5.6	6.5	7.3	8.2	9.1	9.9	10.8	11.7	12.5	13.4
Residential Load Management	Enhanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Load Management	Enhanced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Low Income Weatherization	Enhanced	0.5	1.1	1.8	2.8	4.0	5.4	7.0	8.9	10.8	12.6	14.5	16.4	18.2	20.1	21.9	23.8
Commercial Conservation/Rebates	Enhanced	9.5	17.2	24.9	32.5	40.2	47.9	55.5	63.2	70.9	78.5	86.2	93.9	101.5	109.2	116.8	124.5
Smart Energy Profile	New	4.9	9.7	9.7	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8
Residential Refrigerator Removal	New	0.4	1.3	2.3	3.4	4.4	5.5	6.5	7.6	8.6	9.7	10.7	11.8	12.8	13.9	14.9	16.0
Residential Incentives	New	1.2	2.6	4.8	6.9	9.0	11.2	13.3	15.4	17.5	19.7	21.8	23.9	26.1	28.2	30.3	32.5
Total Existing Programs	All	45.6	69.7	89.8	117.8	130.8	143.9	157.2	170.8	184.4	198.0	211.5	225.1	238.7	252.3	265.8	279.4

8.(3)(e)(4) Projected cost, including any incentive payments and program administrative costs; and

Assuming a 2011 KPSC order for expanded DSM/EE programs, the projected costs are provided below in Table 8.(3)(e)-4.

Table 8.(3)(e)-4
Existing and Proposed DSM Program Costs ($000s)

Program Expenses ($M)	Status	2011	2012	2013	2014	2015	2016	2017	Total
Residential High Efficiency Lighting	Existing	$4.6	$4.4	$4.4	$4.5	$0.0	$0.0	$0.0	$17.9
Residential New Construction	Existing	$1.4	$1.5	$1.3	$1.4	$0.0	$0.0	$0.0	$5.6
Residential HVAC Tune Up	Existing	$0.5	$0.5	$0.5	$0.6	$0.0	$0.0	$0.0	$2.2
Commercial HVAC Tune Up	Existing	$0.5	$0.5	$0.6	$0.6	$0.0	$0.0	$0.0	$2.2
Customer Education & Public Information	Existing	$3.5	$3.7	$3.9	$4.1	$4.2	$4.4	$4.5	$28.3
Dealer Referral Network	Existing	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$1.6
Residential Responsive Pricing (RRP)	Existing	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Program Development & Administration	Enhanced	$1.1	$1.3	$1.3	$1.4	$1.4	$1.5	$1.5	$9.5
Residential Conservation (HEPP)	Enhanced	$1.2	$1.8	$2.2	$2.2	$2.2	$2.3	$2.3	$14.2
Residential Load Management	Enhanced	$9.0	$11.3	$11.1	$12.9	$12.7	$13.2	$13.7	$83.9
Commercial Load Management	Enhanced	$0.5	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6	$4.0
Residential Low Income Weatherization	Enhanced	$2.2	$2.4	$2.4	$2.5	$2.6	$2.6	$2.7	$17.4
Commercial Conservation/Rebates	Enhanced	$3.9	$3.4	$3.5	$3.5	$3.5	$3.5	$3.6	$24.9
Smart Energy Profile	New	$1.4	$2.2	$2.2	$3.3	$3.3	$3.4	$3.4	$19.3
Residential Refrigerator Removal	New	$0.8	$1.6	$1.9	$2.0	$2.1	$2.1	$2.2	$12.7
Residential Incentives	New	$1.7	$2.0	$2.7	$2.7	$2.7	$2.7	$2.8	$17.3
Total Existing Programs	All	$32.5	$37.4	$38.9	$42.6	$35.6	$36.5	$37.5	$261.0

8.(3)(e)(5) Projected cost savings, including savings in utility's generation, transmission and distribution costs.

Over the lives of enhanced, new, and existing/unchanged programs, the projected net present value of the cost savings to the Companies is approximately $864 million.

8.(4) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast:

The Companies' resource planning process considers the economics and practicality of available options to meet customer needs at the lowest practical cost. A study was completed to determine an optimal target reserve margin criterion to be used by the Companies. The results of this study suggested an optimal reserve margin in the range of 15 to 17 percent. In the development of the optimal IRP, the Companies utilized a reserve margin target of 16 percent. Details of this study entitled *LG&E and KU 2011 Reserve Margin Study* (April 2011) can be found in Volume III, Technical Appendix. Information associated with the recommended IRP resulting from the Companies' resource planning process is outlined in Section 8.(5). Results from the Companies' optimal IRP analysis are shown in Table 8.(4) with further details reported in *2011 Optimal Expansion Plan Analysis* (April 2011) in Volume III, Technical Appendix. The in-service years for the units shown are based on the Companies' assumed base load forecast.

Table 8.(4)
Recommended 2011 Integrated Resource Plan

Year	Resource
2011	38 MW DSM Initiatives
2012	58 MW DSM Initiatives
2013	59 MW DSM Initiatives
2014	68 MW DSM Initiatives
2015	61 MW DSM Initiatives
2016	61 MW DSM Initiatives **-797 MW Coal Unit Retirements at Cane Run, Green River, and Tyrone** **907 MW 3x1 Combined Cycle Combustion Turbine**
2017	61 MW DSM Initiatives
2018	58 MW DSM Initiatives **907 MW 3x1 Combined Cycle Combustion Turbine**
2019	58 MW DSM Initiatives
2020	58 MW DSM Initiatives
2021	58 MW DSM Initiatives
2022	58 MW DSM Initiatives
2023	58 MW DSM Initiatives
2024	58 MW DSM Initiatives
2025	58 MW DSM Initiatives **907 MW 3x1 Combined Cycle Combustion Turbine**

Notes:
- DSM initiatives are incremental proposed programs including one program with annual savings that do not accumulate.
- Unit ratings for new units and retirements are summer net ratings.

8.(4)(a) On total resource capacity available at the winter and summer peak:

1. Forecast peak load;
2. Capacity from existing resources before consideration of retirements;
3. Capacity from planned utility-owned generating plant capacity additions;
4. Capacity available from firm purchases from other utilities;
5. Capacity available from firm purchases from nonutility sources of generation;
6. Reductions or increases in peak demand from new conservation and load management or other demand-side programs;
7. Committed capacity sales to wholesale customers coincident with peak;
8. Planned retirements;
9. Reserve requirements;
10. Capacity excess or deficit;
11. Capacity or reserve margin.

Table 8.(4)(a)-1 and Table 8.(4)(a)-2 on the following pages provide the requested information.

Table 8.(4)(a)-1

Kentucky Utilities Company / Louisville Gas and Electric Company
Resource Assesment and Acquisition Plan
Resource Capacity Available (MW)

At Summer Peak

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecasted Peak Load		7091	7210	7356	7477	7603	7654	7760	7897	8094	8285	8392	8517	8671	8897	9083
Peak Reductions																
Interruptible		115	117	121	123	126	126	126	126	126	126	126	126	126	126	126
Existing DSM		182	182	182	182	182	182	182	182	182	182	182	182	182	182	182
Cumulative Incremental DSM		38	91	139	196	237	277	318	356	394	431	469	507	544	582	620
Total Demand	7175	6757	6821	6915	6976	7059	7070	7135	7234	7393	7546	7616	7704	7819	8008	8156
Capacity From:																
Existing Resources	7509	8001	8002	8006	8001	7996	7970	8080	8080	8987	8987	8987	8987	8987	8987	8987
Planned Resources	549	0	0	0	0	0	907		907							907
Firm Purchase (OVEC)	155	155	154	152	152	152	152	152	152	152	152	152	152	152	152	152
Firm Purchases Non-Utility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Committed Capacity Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Retirements	0	0	0	0	0	0	797	0	0	0	0	0	0	0	0	0
Total Supply	8213	8156	8156	8158	8153	8148	8232	8232	9139	9139	9139	9139	9139	9139	9139	10046
16% Reserve Requirements	1148	1081	1091	1106	1116	1129	1131	1142	1157	1183	1207	1219	1233	1251	1281	1305
Excess (Deficit)	-110	318	243	137	61	-40	31	-45	748	563	385	304	203	68	-150	585
Reserve Margin (%)	14.5%	20.7%	19.6%	18.0%	16.9%	15.4%	16.4%	15.4%	26.3%	23.6%	21.1%	20.0%	18.6%	16.9%	14.1%	23.2%

Note: 2010 peak load is from actual peak on 8/4/2010; capacity is from planned including Trimble County Unit 2.

Table 8.(4)(a)-2

Kentucky Utilities Company / Louisville Gas and Electric Company

Resource Assesment and Acquisition Plan

Resource Capacity Available (MW)

At Winter Peak

	2010/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Forecasted Peak Load		6757	6775	6883	7006	7119	7141	7259	7335	7526	7733	7819	7899	8058	8212	8376
Peak Reductions																
Interruptible		117	121	123	126	126	126	126	126	126	126	126	126	126	126	126
Existing DSM		24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Cumulative Incremental DSM		46	66	94	107	120	133	147	160	174	187	201	214	228	242	255
Total Demand	6340	6570	6564	6642	6750	6849	6859	6963	7025	7202	7396	7468	7535	7680	7820	7971
Capacity From:																
Existing Resources	7723	8297	8295	8294	8288	8269	8469	8469	8469	9478	9478	9478	9478	9478	9478	9478
Planned Resources	571	0	0	0	0	1009	0	0	1009	0	0	0	0	0	0	1009
Firm Purchase (OVEC)	162	161	160	158	158	158	158	158	158	158	158	158	158	158	158	158
Firm Purchases Non-Utility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Committed Capacity Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Retirements	0	0	0	0	0	809	0	0	0	0	0	0	0	0	0	0
Total Supply	8456	8458	8455	8452	8446	8627	8627	8627	9636	9636	9636	9636	9636	9636	9636	10645
16% Reserve Requirements	1014	1081	1091	1106	1116	1129	1131	1142	1157	1183	1207	1219	1233	1251	1281	1305
Excess (Deficit)	1102	807	800	704	580	649	637	523	1453	1251	1033	949	868	705	535	1369
Reserve Margin (%)	33.4%	28.7%	28.8%	27.3%	25.1%	26.0%	25.8%	23.9%	37.2%	33.8%	30.3%	29.0%	27.9%	25.5%	23.2%	33.5%

Note: 2010/11 winter peak load is from actual peak on 12/15/2010; capacity is from planned including Trimble County Unit 2.

8.(4)(b) On planned annual generation:

1. **Total forecast firm energy requirements;**
2. **Energy from existing and planned utility generating resources disaggregated by primary fuel type;**
3. **Energy from firm purchases from other utilities;**
4. **Energy from firm purchases from non-utility sources of generation; and**
5. **Reductions or increases in energy from new conservation and load management or other demand-side programs;**

Table 8.(4)(b) on the following page provides the requested information for Items 1-4.

Table 8.(4)(b)

Kentucky Utilities Company / Louisville Gas & Electric Company

Forecast Annual Energy (GWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Energy Requirements	34,727	35,802	36,271	36,741	37,057	37,537	37,985	38,362	38,872	39,510	40,162	40,707	41,344	41,918	42,646	43,290

Energy by Fuel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Coal	32,932	33,966	34,304	35,084	34,863	35,434	33,964	34,381	34,425	34,350	35,239	35,277	35,376	35,976	36,222	36,553
Gas	825	831	811	637	1,031	836	2,559	2,646	3,032	3,686	3,529	4,026	4,519	4,593	5,111	5,415
Oil	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	272	308	315	332	347	380	380	380	380	380	380	380	380	380	380	380

Firm Purchases From Other Utilities	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OMU	580	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OVEC	1,214	677	821	666	794	863	1,058	930	1,012	1,072	991	1,000	1,045	944	906	918
Other	652	1	1	1	1	1	2	3	1	0	1	1	2	3	5	1

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Purchases From Non-Utility	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Reductions / Increases in Energy	0	(410)	(578)	(727)	(923)	(1,016)	(1,110)	(1,203)	(1,301)	(1,397)	(1,493)	(1,588)	(1,684)	(1,780)	(1,876)	(1,972)

Note: 2010 numbers are actuals.

8.(4)(c) For each of the 15 years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.

Table 8.(4)(c) on the following page provides the requested information.

Table 8.(4)(c)

Kentucky Utilities Company / Louisville Gas & Electric Company

Total Energy Input and Total Generation by Primary Fuel Type

Coal	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Energy (GWh)	32,932	33,966	34,304	35,084	34,863	35,434	33,964	34,381	34,425	34,350	35,239	35,277	35,376	35,976	36,222	36,553
Total (000 Tons)	15,364	15,325	15,834	16,196	16,145	16,394	15,588	15,754	15,830	15,766	16,193	16,176	16,260	16,507	16,643	16,787
(000 MMBtus) Consumed	353,758	349,591	352,975	359,740	359,187	364,594	346,458	350,113	352,117	350,293	360,022	359,604	361,620	367,045	370,225	373,386

Gas	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Energy (GWh)	825	831	811	637	1,031	836	2,559	2,646	3,032	3,686	3,529	4,026	4,519	4,593	5,111	5,415
Total (000 MCF)	10,242	10,185	10,002	7,865	12,699	10,337	22,132	22,869	24,169	26,960	25,923	29,711	33,603	34,255	38,413	39,097
(000 MMBtus) Consumed	10,498	10,185	10,002	7,865	12,699	10,337	22,132	22,869	24,169	26,960	25,923	29,711	33,603	34,255	38,413	31,382

Oil	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Energy (GWh)	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total (000 Gallons)	2,720	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(000 MMBtus) Consumed	381	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Hydro	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Energy (GWh)	272	308	315	332	347	380	380	380	380	380	380	380	380	380	380	380

Note: 2010 numbers are actuals.

8.(5) The resource assessment and acquisition plan shall include a description and discussion of:

8.(5)(a) General methodological approach, models, data sets, and information used by the company;

The Companies' resource planning process is comprised of the following: 1) establishment of a reserve margin criterion, 2) assessment of the adequacy of existing generating units and purchase power agreements, 3) assessment of potential purchased power market agreements, 4) assessment of demand-side options, 5) assessment of supply-side options, and 6) development of the optimal economic plan from the available resource options.

To aid in the integrated resource planning process, the Companies use a software package from Ventyx called Strategist® to evaluate resource options. Strategist® is a proprietary, widely used computer model which integrates the supply-side, demand-side, and environmental compliance alternatives to produce a ranked number of plans that meet the prescribed reliability criteria. Strategist® contains several modules, which can be executed in various ways to evaluate resource options. The Load Forecast and Adjustment ("LFA"), Generation and Fuel ("GAF"), Proview ("PRV") and Capital Expenditures and Recovery ("CER") modules of Strategist® are used to evaluate resource options. PRV uses the LFA and GAF modules in a production analysis along with construction expenditure information from the CER to suggest an optimal and several sub-optimal plans based on the minimum present value of revenue requirements ("PVRR") criterion. Strategist® is used in various sensitivity scenarios to determine optimal resource plans. A more detailed description of how Strategist® is used and its input data is contained in a report titled *2011 Optimal Expansion Plan Analysis* (April 2011) in Volume III, Technical Appendix.

Demand Side Management Resource Screening and Assessment

Prompted by the 2008 IRP and the Companies' ongoing review of current DSM/EE programs and research into possible new programs, the Companies began formulating concepts for enhanced and additional DSM/EE programs in 2009. Through additional quantitative screening of the initial 80 DSM/EE programs that were assessed for inclusion in the 2008 IRP, the Companies presented a more refined set of 17 program enhancements and proposals to their Energy Efficiency Advisory Group in September 2009 to obtain feedback about their existing and proposed programs. The group reviewed 17 enhancements and new programs, finding 10 of them to be useful, relevant, and a prudent use of consumer dollars.

Based on feedback from the September 2009 meeting, the Companies conducted further analysis on the identified 10 programs. When additional analysis was completed, the Companies held another meeting in July 2010 with the Energy Efficiency Advisory Group to obtain further feedback. In this meeting, the group was provided an overview of the 10 programs that were analyzed for inclusion in this Application. The third opportunity for the Companies to communicate with representatives of various customer groups came in November and December of 2010. The eight enhancements and new programs to be filed with the KPSC in early 2011 are as a result of the combined effort of the Companies and the Energy Efficiency Advisory Group.

In addition to the analysis provided in the 2008 IRP and the collaborative effort described above, the Companies applied to their existing and proposed DSM/EE programs the industry-standard cost-benefit tests set out in the California Standard Practice Manual, which the KPSC explicitly requires utilities to apply: "Any new DSM program or change to an existing DSM program shall be supported by … [t]he results of the four traditional DSM cost-benefit tests [Participant, Total Resource Cost, Ratepayer Impact, and Utility Cost tests]." Each of the new and enhanced programs proposed in this Application passed the Participant and Total Resource Cost tests.

The ability for the Companies to mitigate energy consumption through increased energy efficiency programming has also been reviewed by an independent third party evaluation company, ICF International. ICF is a global consulting firm that specializes in energy and climate change, among other areas.[3] Upon review of the proposed portfolio of programs to be presented to the KPSC in early 2011, ICF concluded that the portfolio contains many elements of best practices, including cost-effectiveness, broad targeting, and flexible design; developed additional programs targeting the commercial sector based on a market characterization study; and that the Companies should continue to market their successful load control program, and offer additional demand response options.

On the basis of the above-described analyses and collaboration, the Companies propose to enhance and extend through December 31, 2017, the following existing DSM/EE programs: Residential and Commercial Load Management / Demand Conservation Program, Commercial Conservation / Commercial Incentive Program, Residential Conservation / Home Energy Performance Program, Residential Low Income Weatherization Program (WeCare), and Program Development and Administration.

The Companies further propose to add the following new DSM/EE programs to their current offerings: Smart Energy Profile Program, Residential Incentive Program, and the Residential Refrigerator Removal Program.

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3 *See* http://www.icfi.com.

Supply Side Resource Screening Assessment

Both mature and emerging technologies were evaluated as supply side resources in the integrated resource planning process. The EPRI Technical Assessment Guide ("EPRI TAG") as well as the *Cummins and Barnard Generation Options Technology Study* report dated December 2007 were utilized to perform the detailed screening analysis. EPRI TAG was used to update the mature and developed technologies whereas the Cummins & Barnard report was used for some experimental technologies. Additional detail on this process is contained in the report titled *Analysis of Supply-Side Technology Alternatives* (March 2011) contained in Volume III, Technical Appendix.

8.(5)(b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;

In order to meet growing customer needs, the Companies' existing generation system and various possible options (both demand-side and supply-side) are modeled to determine the optimal expansion plan for the snapshot in time. Several key assumptions and uncertainties are encountered during this process: forecast fuel prices, forecast customer load requirements, both capital and operating expenses related to new generation construction, Clean Air Act Compliance, potential regulation of hazardous air pollutants from coal- and oil-fired electric utility generating units, potential regulation of CO_2 emissions, potential regulation under Clean Water Act section 316(b) of cooling water intake structures, the availability of existing as well as new generating units and purchases, weather uncertainties, the aging of generating units, and fuel cost uncertainty. Each of these key issues is discussed in the subsections that follow.

Fuel Forecast

The Companies' fuel forecasts are updated annually as part of the Companies' planning cycle. The Companies solicit contract bids for coal to satisfy the near term needs of each plant. The first five years of fuel forecast is a combination of the prices of the current contracts in place and the forward price curve. Beyond that five-year period, coal prices are based on pricing from the Hill and Associates forecast and an escalation factor is applied for transportation to the individual plants for the remaining years in the forecast. Fuel oil prices are projected by the NYMEX forecast, since all fuel oil purchases are made as spot purchases on an "as-needed" basis.

The natural gas price forecast continues to be derived from the NYMEX futures contract price at the time the Companies' forecast is developed, plus a pipeline basis and pipeline transportation estimate for deliveries to the Companies' plant sites. Said another way, the forecast is simply a "snapshot" of forward market prices at the time the forecast is made. The use of the NYMEX futures contract price at the time the Companies' forecast is developed has proven to be an objective method of assessing the price of natural gas from an independent and transparent source of reliable information.

A significant factor influencing the Companies' optimal IRP is the Companies' fuel forecast. The combustion turbine and the combined cycle technologies, for example, are gas-fired, while the supercritical pulverized coal unit is a coal-fired technology. Thus, gas and coal prices may have a significant impact on the selection of an optimal technology type. The Companies develop 30-year base fuel forecasts for all fuels that are either used or could be used at existing plants. Sensitivity fuel forecasts are then developed depicting high and low fuel cost scenarios on the screened technologies. Representative fuel costs for each technology screened were obtained from the base and sensitivity fuel forecasts. Fuel sensitivities factored into the screening of supply-side technologies are discussed in the report titled *Analysis of Supply-Side Technology Alternatives* (March 2011) contained in Volume III, Technical Appendix.

Forecasted Customer Load Requirements

The load forecast (energy and demand) is another significant factor influencing the Companies' optimal resource plan analysis. Each resource option is designed or selected – within a system context -- for optimal performance at a specific level of utilization. For instance, CTs have relatively low construction costs (compared to coal-fired units), but have high operation and maintenance costs. Conversely, coal-fired units have high construction costs (per kW of installed capacity), but have much lower fuel and O&M costs. The economics of adding any unit to a generation system depends on the lifetime duty which that unit will perform. Significant economic penalties (higher-than-planned costs of system development and operation) may be incurred if a unit is operated for an extended period outside its design duty range.

In developing a portfolio of generating assets, it is important to ensure that the economics of the selected expansion plan are robust within a reasonable range of load growth uncertainty. For example, if load growth turns out to be higher than expected, CT capacity -- added to meet peak demands only – may be called upon for intermediate duty, adding significant cost to system operations. Conversely, with lower-than-expected load growth, baseload capacity may be under-utilized. The planning function must consider the impacts of uncertainty in load growth on system economics and – recognizing the necessary lead-times required to construct different types and sizes of plant – develop an expansion plan which provides appropriate flexibility throughout the planning term.

To address this issue, the Companies incorporate load sensitivity analysis into the process of developing the optimal IRP. In summary, three load forecasts were developed to depict an expected system load growth case, a case where system load growth exceeds expected growth, and a case in which system load growth is less than expected. The resulting forecasts are referred to respectively as the "base," "high," and "low." The details of and the basis for the various load forecasts are described in Volume II, Technical Appendix.

New Unit Estimated Costs

A significant change in either the capital or operating cost of a new unit can result in a different selection of units in the optimal IRP strategy. Since the 2008 IRP, the capital costs for both the coal and gas units have decreased by 20% and 10% respectively due primarily to the impact of the economic downturn on commodity supply costs. However, coal units still require a higher capital cost compared to gas units, but by a smaller margin. The list of recommended technologies to be used for the 2011 expansion planning is similar to list of technologies that was used for the 2008 expansion planning. The source of the data used in this evaluation is EPRI TAG as well as the *Cummins and Barnard Generation Technology Options Study* report dated December 2007. TAG was used to update the mature and developed technologies whereas Cummins & Barnard information was mostly used for the experimental technologies. EPRI TAG and the C&B report contained various supply-side technology types, descriptions and technical explanations, capital costs and capital cost ranges, facility megawatt sizes, fuels and other technology-specific parametric data from engineering cost studies. As discussed in the report titled *Analysis of Supply-Side Technology Alternatives* (March 2011) contained in Volume III, Technical Appendix, a base, low and high capital cost sensitivity was incorporated into the screening analysis.

Clean Air Act Compliance Plan

A large amount of regulations have been produced as a result of the Clean Air Act and its Amendments which affected facilities must follow. Over the years, the Companies have implemented strategies to ensure compliance with applicable regulations. In recent years, the most prominent regulations have involved emissions of nitrogen oxide, sulfur dioxide and hazardous air pollutants.

Nitrogen Oxide

To comply with programs implemented under the Clean Air Act Amendments ("CAAA") of 1990, the Companies have completed a number of major projects to reduce the amount of NO_x emitted from its steam generating plants. The required NO_x reductions were achieved by the Companies through the installation of SCRs and other NO_x control technologies such as advanced low-NO_x burners, overfire air systems, and neural networks on many of its generating units to enable better control of the boiler combustion process. Between 1990 and 2000, the Companies reduced their NO_x emissions by over 40 percent by installing low NO_x burners and overfire air systems. These installations were performed during regularly scheduled maintenance outages (to minimize asset down time). Implementation of these actions on many of the Companies' units constituted the initial phase of the Companies' NO_x compliance efforts.

Completion and operation of the Companies' first SCR installation on existing units occurred in 2002 and the most recent SCR installation on existing units came on-line in May 2004. SCR installations have been performed on six of the Companies' baseload generating units (Trimble County Unit 1; Mill Creek Units 3 and 4; and Ghent Units 1, 3, and 4). Additionally, Trimble County Unit 2, which became commercially operational in January 2011, is equipped with an SCR and a new SCR is planned to be operational on Brown Unit 3 in May 2012.

The SCR process is the most aggressive means of post-combustion NO_x removal currently available to coal-fired boilers and provides the greatest degree of control. An SCR is a large, reactive "filter," about the size of a ten-story building that houses a catalyst used to convert the NO_x emissions into the components of nitrogen and water. Like the annual SO_2 allocation program under the Acid Deposition Control Provisions of the CAAA of 1990, EPA's NO_x regulations (including the Clean Air Interstate Rule) allow for the totaling of NO_x emissions over the Companies' entire system and do not require compliance by each individual unit or site location. Therefore, to reduce compliance costs, the Companies are reducing NO_x emissions more than required on some of its generating units to stay below a system-wide emission tonnage cap.

The Clean Air Interstate Rule was finalized on March 10, 2005. Under CAIR, in addition to the continuation of an ozone season NO_x reduction program, a new annual NO_x reduction program began in 2009. However, CAIR was remanded back to EPA for further consideration. The Court allowed CAIR to remain in effect until modifications or new rules were promulgated. Under CAIR's annual and ozone season NO_x reduction programs, compliance has required year-round operation of the SCR currently installed at Company facilities and the need to meet lower NO_x emission caps.

EPA has been working on a replacement to CAIR termed the Clean Air Transport Rule. Several proposals have been published for public comment. It is believed that CATR is scheduled to be published in the summer of 2011. The proposals to date indicate that CATR will have similar reduction targets as CAIR. However, those targets will be on an earlier time frame.

The first compliance year will likely be 2012 (instead of 2015) and additional reduction will likely be required starting in 2014 (instead of 2018). Additionally, the proposals have indicated that a new trading program for NO_x and SO_2 allowances will be developed. Further indications are that this program will have very limited interstate trading abilities.

Sulfur Dioxide

Although the Companies' larger coal-fired generating units are already fitted with FGDs, additional reduction of SO_2 seem likely to be needed to comply with proposed future SO_2 reduction programs to be implemented under the CAAA. Phase II of the Acid Deposition Control Program ("Acid Rain Program") of the CAAA established an annual SO_2 emissions cap at approximately 8.9 million tons by the year 2000 for the entire nation. The Companies' current operations emit more than its allotted annual SO_2 emissions, but the extra emissions are allowed because the Companies' have a "bank" of saved emission allowances. These allowances were accrued in the years prior to 2000 when the Companies' produced less than their annual SO_2 emission allotment and could save or bank the difference between the emitted SO_2 and the former SO_2 cap.

The Companies' have used these accrued allowances since 2000 to offset SO_2 emissions in excess of the annual limitation. Additionally, the Companies' have increased the removal efficiencies of existing FGD units to conserve these emission allowances. If these emission allowances are depleted, the Companies would be forced to purchase allowances from the market or find a way to make additional reductions in SO_2 emissions.

Additionally, the Acid Rain Program was supplemented in 2010 by the SO_2 program of the CAIR. CAIR's SO_2 program targeted reductions of the Companies allowable SO_2 emissions by around 50 percent in 2010 and was aiming at a 65 percent in 2015. As a result of the Acid

Rain Program and CAIR, the Companies began construction of a number of projects to reduce fleet-wide SO_2 emissions, including the installation of FGDs on Ghent Units 2[4], 3 and 4 and E.W. Brown Units 1, 2, and 3. Installation of these FGDs was completed between May 2007 and June 2010.

There are many different designs of FGD equipment. The new equipment installed for Ghent and E.W. Brown units are wet limestone, forced-oxidation systems that are among the highest in SO_2 capture efficiency. These systems are very similar to the FGD equipment already in use at the Trimble County Station, and use a similar process to the less efficient, first generation FGD equipment in use at the Ghent and Mill Creek Stations. A generalized description of this system would consist of crushing and slurrying the limestone material into liquid form and introducing it into the flue gas stream, typically by spraying it. The limestone reacts with the SO_2 gas creating a product in solution that falls out of the flue gas stream. The resulting liquid is collected and air is forced into it to further oxidize the material turning it into synthetic gypsum. Depending on the quality of the gypsum, it can be used for beneficial re-use projects (i.e. sold to wallboard makers, used as structural fill material, etc.). Cane Run Station also utilizes FGD equipment; but, it is an older and slightly different design. Cane Run's FGD equipment uses a scrubbing process in which lime (not limestone) is slurried and sprayed into the flue gas stream. The lime reacts with the SO_2 and the resulting liquid is collected and processed into a solid material that is landfilled at Cane Run Station.

As mentioned previously, EPA will likely issue CATR in the summer of 2011 as the replacement to CAIR. This rule will require the reduction of SO_2 emissions similar to CAIR, but on a quicker time schedule (Phase 1 in 2012 and Phase 2 in 2014). Additionally, the previously

[4] The existing FGD on Ghent Unit 1 was re-configured to Ghent Unit 2 and a new FGD was added to Ghent Unit 1.

banked allowances used in the Acid Rain Rule and CAIR will likely not be usable within CATR. The indications are that CATR will create a new trading program and issue all new allowances for affected facilities.

Additionally, EPA published a final rule on June 22, 2010 to revise the current primary SO_2 NAAQS. Kentucky must incorporate this new NAAQS into its state implementation plan. Additionally, the SIP must contain a plan to get any non-attainment areas into attainment with the standard by June 2017, meaning upgrades or replacement of controls may be needed by 2016.

In summary, all of these SO_2-related regulations will and have required the Companies to evaluate compliance methodologies and potential options. This document encompasses those evaluations.

Hazardous Air Pollutants

On May 18, 2005, EPA delisted electric generating units from the list of sources subject to hazardous air pollutant controls under Section 112(c) of the Clean Air Act and promulgated the Clean Air Mercury Rule which would have established a two phase "cap and trade" program for reduction of mercury emissions from those units. A cap and trade program, which allowed a company to target specific units for control to meet a system-wide target, would have been a much more cost-effective mechanism than the unit-by-unit controls that could otherwise be applicable under Section 112(c) of the Clean Air Act.

However, on February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAMR on the grounds that EPA failed to follow the correct procedures for delisting electric generating units from regulation under Section 112(c) of the Clean Air Act. In February 2009, EPA decided to drop any further legal proceedings regarding CAMR and began focusing on developing a rule to set MACT standards that would apply to all electric generating units that are major sources of hazardous air pollutants (including mercury, other metals, dioxins and other organic compounds). In January 2010, EPA submitted an information collection request to the electric generating industry to gather more data (including requesting new emissions testing) to aid in the development of the new MACT standards.

On March 16, 2011 EPA proposed the rule for these new MACT standards. As proposed, the regulation places numeric limits on mercury, non-mercury metallic HAPS, and acid gas HAPS emissions. The proposal also sets work practice standards to minimize and reduce HAPS emissions. EPA will be accepting comments on the rule for a 60-day period following their publication in the Federal Register. EPA will take those comments into consideration before finalizing the rule. EPA is under legal obligations to promulgate a final rule by November 16, 2011. The Companies are analyzing the proposed rule for impacts to the Companies including the potential need for more emission controls to ensure compliance. Until such time as the final rule is published, there will continue to be substantial uncertainty as to future requirements of hazardous air pollutant regulations for electric generating units. This IRP assumes that fabric filter bag houses will be required on all coal units to satisfy the upcoming MACT standards.

Existing and New Unit/Purchase Availability

The Companies' existing capacity resources encompass both owned generating units and purchase power agreements. A significant amount of historical data exists on these units and was used to model the future availability of the units. The availability of new generating units and purchases was determined based on the Companies' experience and projected availability from both the EPRI TAG and the Cummins & Barnard report titled *E.ON US Generation Technology Options* (December 2007).

The Companies are two of eight sponsoring companies of OVEC and presently receive 8.13 percent of the equity in the generating capacity. KU retains its 2.5 percent ownership and LG&E ownership became 5.63 percent pursuant to the Amended and Restated Inter-Company Power Agreement dated as of March 13, 2006, filed with and approved by the KPSC in Case No. 2004-00396. The anticipated summer capacity the Companies rely upon from OVEC is 155 MW net, with varying capacity during the remaining months.

Market forces can drastically affect the availability and prices of purchase power from the wholesale market as a future resource. The Companies accounted for the uncertainty of price spikes and their respective impact on meeting peak demands in the optimization studies by excluding peaking type power purchases from the IRP analysis. Peaking type purchase power opportunities in optimization studies would serve only to evaluate delaying new unit construction for short periods of time, which is already being considered in detail by the Companies' RFP process.

Uncertainty in the Planning Process Caused by Weather

The recent experience of 2010 shows that during extreme summer weather conditions and peak load periods, the Companies' reserves are approaching maximum utilization. The Companies' planned reserve margin was estimated prior to the summer season to be 23 percent. This figure assumed Trimble County unit 2 would be in service. Without Trimble County unit 2, the planned reserve margin was 15 percent. Due to extremely warm summer temperatures on the peak day, the actual operating margin – not considering the need to carry spinning and operating reserves – was 6.1 percent in 2010. The differences between the expected reserve margin and the actual operating margin were due to the variances in load, the available generation, the reduced capacity available due to equipment problems, and the available purchases.

During the hour ending 3 p.m. Eastern Standard Time on August 4, 2010, the Companies' peak load was 7,175 MW. This is slightly higher than the Companies' previous all-time peak load (including buy-thru customers' load) of 7,132 MW which was established on August 9, 2007. The Companies' planned August 2010 capacity rating was 8,058 MW, including firm purchases from OVEC of 155 MW and the 549 MW from the anticipated operation of Trimble County Unit 2. At the time of the 2010 peak, the Companies' resources were composed of KU/LGE-owned units and 121 MW of native-load purchases from OVEC. On the 2010 summer peak day, actual capacity available for native load from Company owned units was 859 MW less than the summer rating due to unit outages and derates: at the Ohio Falls Station, one unit is out of service until it undergoes rehabilitation (6 MW) and four units were unavailable due to low flow river conditions (24 MW); one coal unit experienced a forced outage (479 MW); four combustion turbines were unavailable due to forced outages (198 MW); derates on coal units and combustion turbines attributed to losses of 109 MW and 14 MW respectively; and, a loss of 29 MW on the combustion turbines was attributed to the extreme ambient conditions. Further, Trimble County Unit 2 (549 MW) was not yet available for commercial operation. There were 836 MW of spot market purchases made at the time of the peak. These factors coupled with a higher than planned peak load (+490 MW) due to warmer than normal peak-day temperatures resulted in an operating margin of 6.1 percent or 441 MW. Moreover, when the need to carry operating and spinning reserves is considered (approximately 360 MW), the operating margin is even lower (1.1% or 81 MW).

Table 8.(5)(b)-1 shows pertinent system data for the 2010 summer peak day. Figure 8.(5)(b) complements Table 8.(5)(b)-1 and illustrates the magnitudes of the Companies' daily summer peak loads during July and August of 2010. As shown in Table 8.(5)(b)-1, the

Companies' actual operating margin can be either more or less than expected. Actual operating margin levels vary as a result of abnormal weather, unit equipment problems, and the unavailability of contract purchases.

Table 8.(5)(b)-1

Recent Summer Load Experience

Day	**8/4/2010**
Hour (EST)	**15:00**
Day of Week	**Wednesday**
Planned Capacity	
Utility Owned	8,058
Firm Purchase Contract	155
	8,213
Forecasted Peak Demand	**6,685**
Planned Reserve Margin	
Megawatts	1,528
Margin (%)	***22.9%***
Available Capacity [1]	
Utility Owned	6,659
Firm Purchase Contract	121
Spot market purchases [2]	836
	7,616
Actual Peak Demand	**7,175**
Outages	
Forced	707
Derate	152
Scheduled	0
TC2 not commercial	549
	1,408
Actual Operating Margin	
Megawatts	441
Margin (%)	***6.1%***

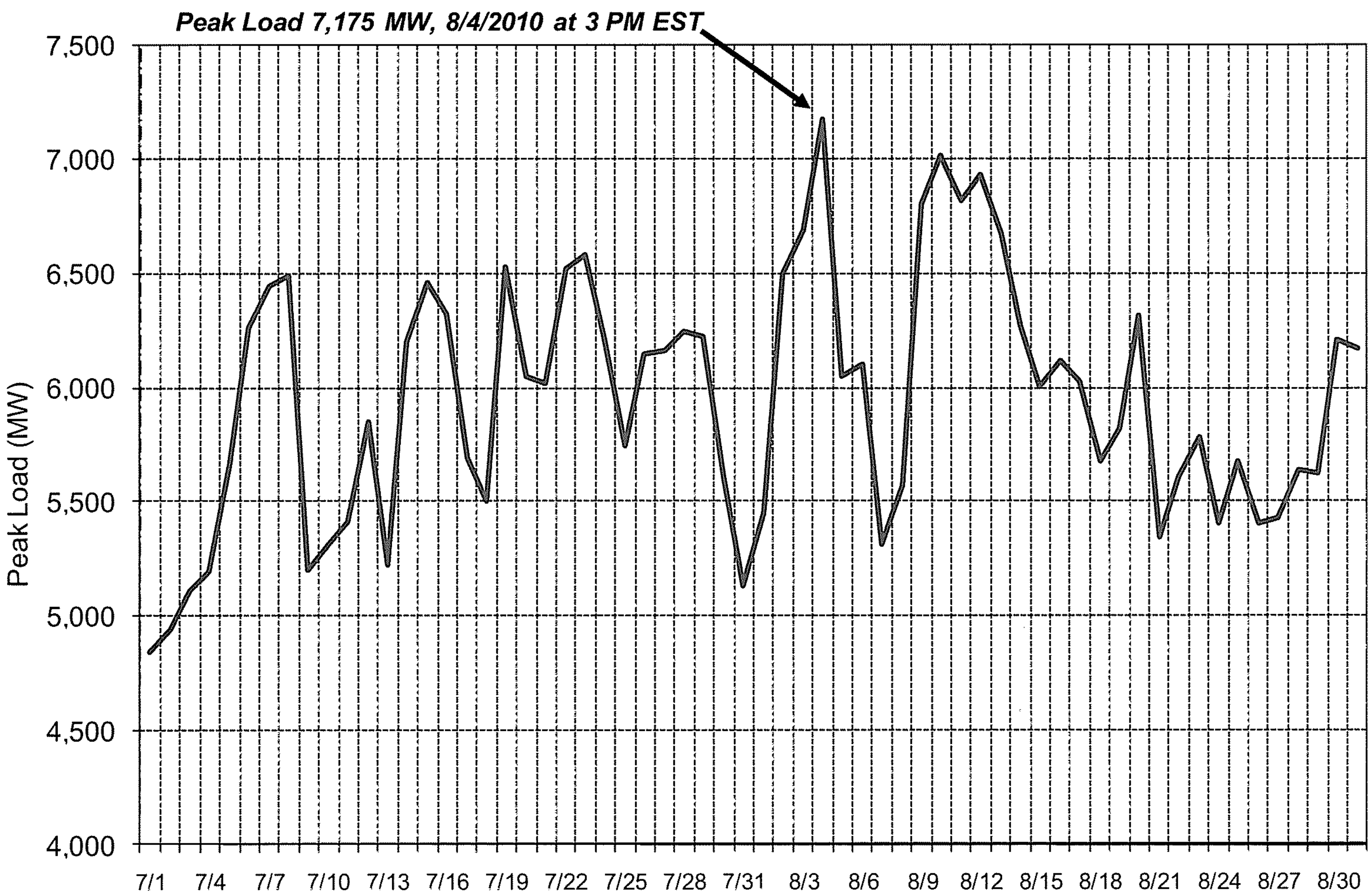
Notes

[1] Available Capacity is defined as the planned capacity less all outages and adjusted for actual hourly Ohio Falls generation.

[2] Spot market purchases can be made to displace higher cost owned generation and will be utilized to meet peak demand before other owned Available Capacity.

Figure 8.(5)(b)

Kentucky Utilities Company / Louisville Gas and Electric Company
July 2010 - August 2010 Native Load Experience



Potential Regulation of CO_2 Emissions

In addition to the actions already mentioned regarding the Clean Air Act, Congress has considered legislation to control emissions of greenhouse gases and/or CO_2. While legislative efforts have faltered, the EPA has proceeded down the path of issuing regulations (on September 22, 2009) for the reporting of GHG emissions from a large amount of sources (facilities with more than 25,000 metric tons of carbon dioxide equivalent emissions or a maximum rate heat input capacity of more than 30 MMBtu/hr). Annual reporting to EPA has been extended to September 30, 2011.

On March 13, 2010, EPA issued the greenhouse gas "Tailoring Rule" which became effective on January 2, 2011. This rule sets thresholds for requiring permitting of greenhouse emissions for new or modified sources. Therefore, future evaluations of major projects will be required to evaluate whether the projects trigger the need to perform BACT evaluations of GHG emissions. GHG BACT is expected to be developed over time, but initially will focus primarily on energy efficiency until other options become available and feasible.

In December 2010, EPA also announced a plan to propose NSPS regulations for GHG emissions from the electric utility industry by July 26, 2011 with potential finalization to occur in May 2012. These new rules would set emission requirements for new and modified electric generating units ("EGU") and set guidelines for existing EGUs. EPA has indicated that they will coordinate these rules with other rules due out near the same time (i.e., hazardous air pollutants, Clean Air Transport Rule), but until more information is provided, the potential impact of these rules is uncertain. The Companies will continue to review this issue.

316 (b) – Regulation of cooling water intake structures

Section 316(b) of the Clean Water Act requires that cooling water intake structure reflect the best technology available ("BTA") for minimizing "adverse environmental impacts" to aquatic organisms. EPA has developed rules to implement Section 316(b) in three phases: new facilities, existing electric generation facilities, and existing manufacturing and small utility and non-utility power producers. In December 2001, EPA promulgated the Phase I new facility rule establishing cooling towers as BTA.

A final rule for Phase II existing electric generation facilities became effective on September 7, 2004. However, this final rule did not establish cooling towers as BTA. Rather, this rule set significant new national technology-based performance standards aimed at minimizing the adverse environmental impacts by reducing the number of aquatic organisms lost as a result of water withdrawals or through restoration measures that compensate for these losses.

However, the regulation was challenged by environmental groups as not strong enough to protect aquatic populations and was ultimately struck down by the U.S. 2nd Circuit Court in 2007. EPA rescinded the rule on January 6, 2008 and began drafting a new set of regulations.

EPA proposed the new rule on March 28, 2011 and is anticipating a final rule by July 2012. The Companies expect both industry and environmental groups will utilize the court system to again challenge the new rule and possibly delay implementation deadlines. The regulations will address both impingement and entrainment issues, thus affecting the Companies facilities, including those already equipped with closed cycle cooling (cooling towers). Possible requirements within the rule could include: cooling towers on all active units, "helper" towers on once-thru cooling units for use during spawning season and low flow periods, fine mesh screens (1-2 mm) for water intake, fish return systems associated with the screens, and/or annual in-stream fish studies. These potential capital investments could be required within the time period of this IRP document. The Companies will continue to review this issue.

Aging Generating Units

The generating units in the Companies' fleet continue to age. Some of the oldest steam-generating units across the system include Tyrone Unit 3, Green River Units 3 and 4, and Brown Unit 1, as can be seen in Table 8.(5)(b)-2. Each of these units is over 50 years old, which is beyond the typical design life for a coal-fired unit. Some of the oldest combustion turbines are the smaller-sized LG&E combustion turbines and the KU Haefling combustion turbines. Each of these units is over 30 years of age, which is considered the typical life expectancy for small frame combustion turbines.

Having operated past their design lives, these units run a greater risk of a catastrophic failure than other units. The economics surrounding the continued operation of these units are periodically reviewed to ensure the efficiency of the overall system. Higher production costs, as well as environmental restrictions, continue to worsen the economics of these units. Hence, the economics to retire any of these units could take place even without a significant mechanical failure of a given unit. Any decision to retire generation earlier would change future capacity needs.

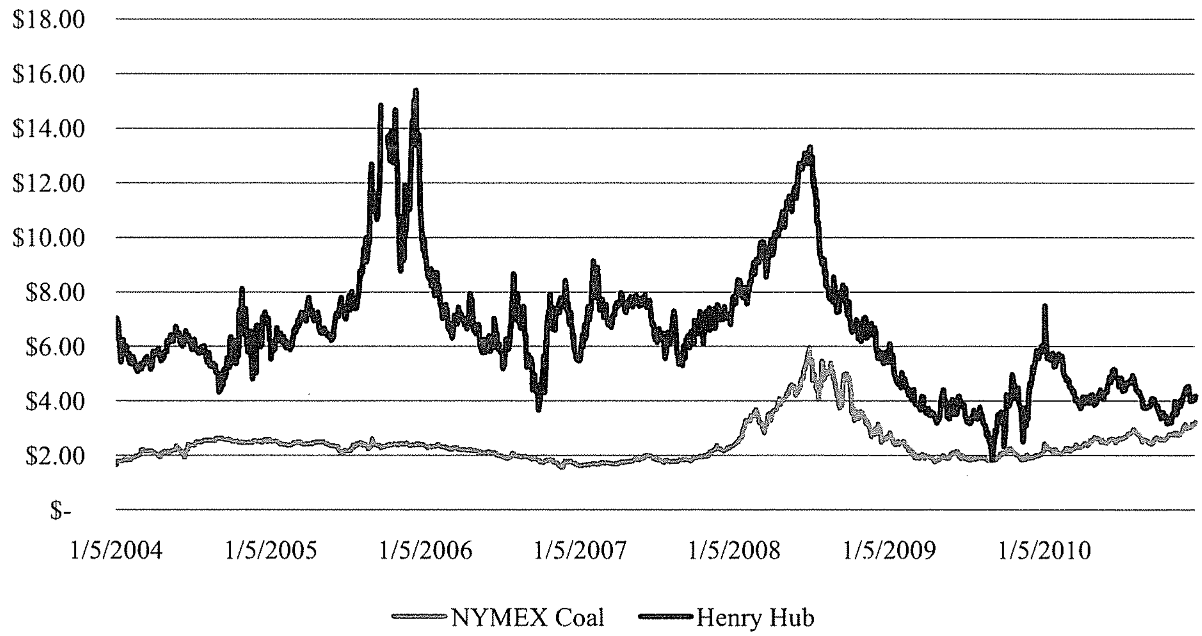
Table 8.(5)(b)-2
Aging Units

Fuel	Plant Name	Unit	Summer Capacity (MW)	In Service Year	Age (Years)
Coal	Tyrone	3	71	1953	58
Coal	Green River	3	68	1954	57
Coal	Brown	1	101	1957	54
Coal	Green River	4	95	1959	52
Gas	Cane Run	11	14	1968	43
Gas	Paddy's Run	11	12	1968	43
Gas	Paddy's Run	12	23	1968	43
Gas	Zorn	1	14	1969	42
Gas	Haefling	1,2,3	36	1970	41

Fuel Cost Uncertainty

Fuel prices are sensitive to market factors such as weather swings, demand driven scarcity, or supply disruptions. In recent years, Hurricanes Katrina and Rita impacted Gulf Coast natural gas production in the fall of 2005. In the summer of 2008, gas production outages, low inventories and low LNG imports tightened the gas market. That same summer, demand/supply issues in the coal markets pushed spot coal prices substantially higher. Since 2008, there has been a considerable increase in domestic gas production levels from shale deposits, and in estimates of economically recoverable natural gas from shale. The data in Table 8.(5)(b)-3 is from the Ventyx (formerly Global Energy) Velocity Suite database for historic next day Henry Hub spot price and NYMEX Central Appalachian coal futures prompt contract settlement prices. In general, the spikes which occasionally occur in the fuel markets are due to some fundamental driver tightening the market as opposed to speculation, and the high price signals incent the market to adjust both demand and supply to restore balance.

Table 8.(5)(b)-3
Henry Hub Spot Gas and NYMEX Coal Price



8.(5)(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan;

Demand-side Management Screening

The benefit/cost calculations for the program plan were performed using DSMore, a PC-based software package developed by Integral Analytics, Inc. This software has replaced DS Manager, which was used to provide the benefit/cost calculations in prior expansion filings. DSMore provides more robust analytics surrounding weather and market conditions and a more transparent platform to understand the underlying calculations associated with the benefit/cost tests. The Companies calculated the four benefit/cost tests contained in the <u>California Standard</u>

Practice Manual: Economic Analysis of Demand-Side Programs and Projects ("Manual").[5] These tests and their Manual definitions are:

- **The Participant Test:** The Participant Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.[6]
- **The Ratepayer Impact Measurement Test:** The Ratepayer Impact Measure ("RIM") test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation is less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.[7]
- **The Total Resource Cost Test:** The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change

5 The Manual is available online at: http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF
6 Manual at 8.
7 Manual at 13.

and the incentive terms intuitively cancel (except for the differences in net and gross savings).[8]

- **The Program Administrator Cost Test (or "Utility Cost Test"):** The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC [Total Resource Cost] benefits. Costs are defined more narrowly.[9]

The Companies' analysis associated with each DSM/EE program are depicted in the Table 8.(5)(c)-1.

8 Manual at 18.
9 Manual at 23.

Table 8.(5)(c)-1

Status	Program	DSMore Scoring: Participant Test	Utility Cost Test	Ratepayer Impact Test	Total Resouce Cost Test
Existing	Residential High Efficiency Lighting	8.50	3.32	0.47	2.26
	Residential New Construction	2.45	2.73	0.77	1.52
	Residential HVAC Tune Up	8.28	1.44	0.66	1.26
	Commercial HVAC Tune Up	23.45	3.40	0.77	2.96
	Customer Education & Public Information	NA	0.00	0.00	0.00
	Dealer Referral Network	NA	0.00	0.00	0.00
	Residential Responsive Pricing (RRP)	NA	0.00	0.00	0.00
Revised	Program Development & Administration	NA	0.00	0.00	0.00
	Residential Conservation (HEPP)	5.69	1.85	0.55	1.42
	Residential Load Management	NA	1.93	1.35	3.62
	Commercial Load Management	NA	2.53	1.76	3.95
	Residential Low Income Weatherization	NA	2.08	0.60	2.08
	Commercial Conservation/Rebates	7.03	16.40	1.00	6.15
New	Smart Energy Profile	NA	2.36	0.60	2.36
	Residential Refrigerator Removal	NA	1.53	0.44	1.84
	Residential Incentives	3.28	4.50	0.80	2.31

Overall Portfolio (Existing, Revised, & New)	**8.24**	**3.39**	**0.82**	**3.01**

As demonstrated, each program each program passes the Participant, Utility Cost, and Total Resource Cost tests with a score of "1" or higher.

Supply-side Screening

As a precursor to the optimization process, a technology screening analysis was conducted. The purpose of the screening analysis was to evaluate, compare and suggest the least-cost supply-side options to use in Strategist® optimizations. The following is a summary of the technology screening methodology and subsequent findings. A detailed report of the screening analysis titled *Analysis of Supply-Side Technology Alternatives* (March 2011) can be found in Volume III, Technical Appendix.

The relative cost and performance of current/advanced electric generation and storage technologies was extracted from EPRI TAG and the Cummins & Barnard report. No technology was excluded from the screening analysis based solely on its technical maturity, practicality, or feasibility.

In order to pass a comprehensive list of supply side options to Strategist® for evaluation in the optimal expansion plan, a base analysis plus sensitivities are incorporated into the screening analysis. Emissions allowance costs are included to account for regulations limiting SO_2 and NO_x. However, due to anticipated environmental regulations, allowance price forecasts for NO_x and SO_2 are significantly lower in 2011 through 2013 compared to recent years and then are assumed to be zero after 2013 Sensitivities are utilized to provide valuable information on how each technology will perform under various operating conditions. The sensitivities contained in this analysis are based on variations in capital cost, technology operating efficiency (measured by heat rate), and fuel cost. Each sensitivity variable has three possible scenarios: base, low, and high, which results in 27 sensitivity combinations.

For each of the three sensitivity variables, high and low values were estimated, in addition to the base values supplied by EPRI TAG and C&B. The percent adjustment made to capital costs also originate from C&B based on their research and project experience. The adjustment to the heat rate is a 5 percent decrease and increase from the base heat rate to adequately represent increased or decreased operating performance of the technology over the designed heat rate. The adjustment to the fuel cost is a 10 percent decrease or increase from the base fuel prices. The Companies develop 30-year base fuel forecasts for all fuels that are to be used at existing plants. For the other technologies, the base fuel costs are estimated based on research or data provided by Cummins and Barnard.

The 30-year levelized screening analysis determined the total annual cost of owning and operating each technology under each of the 27 scenarios and over a range of capacity factors from 0 to 100 percent in 10 percent increments. The 30-year levelized cost of each unit option over various capacity factor ranges is displayed in Table 8.(5)(c)-2 for the base case combination of sensitivity variables. The shaded areas represent the least cost $/kW-yr for each capacity factor level shown. Figure 8.(5)(c)-3 is a graphical representation of the base case least-cost technologies identified in Table 8.(5)(c)-2. The annual capital cost of each unit is calculated using a fixed charge rate. Fixed and variable operation and maintenance costs are included and fuel cost is assumed to be a linear function of capacity factor.

The first, second and third least-cost alternatives over each capacity factor range were identified in all 27 scenarios. A total of 11 different technologies were initially identified as first, second or third least cost alternatives in the base case. After review, however, it was determined that several of these should be removed from the initial list; the reasons are addressed in the report titled *Analysis of Supply-Side Technology Alternatives* (March 2011) in Volume III, Technical Appendix in the subsection titled *Base Analysis*.

Table 8.(5)(c)-2
Levelized Cost at Various Capacity Factors

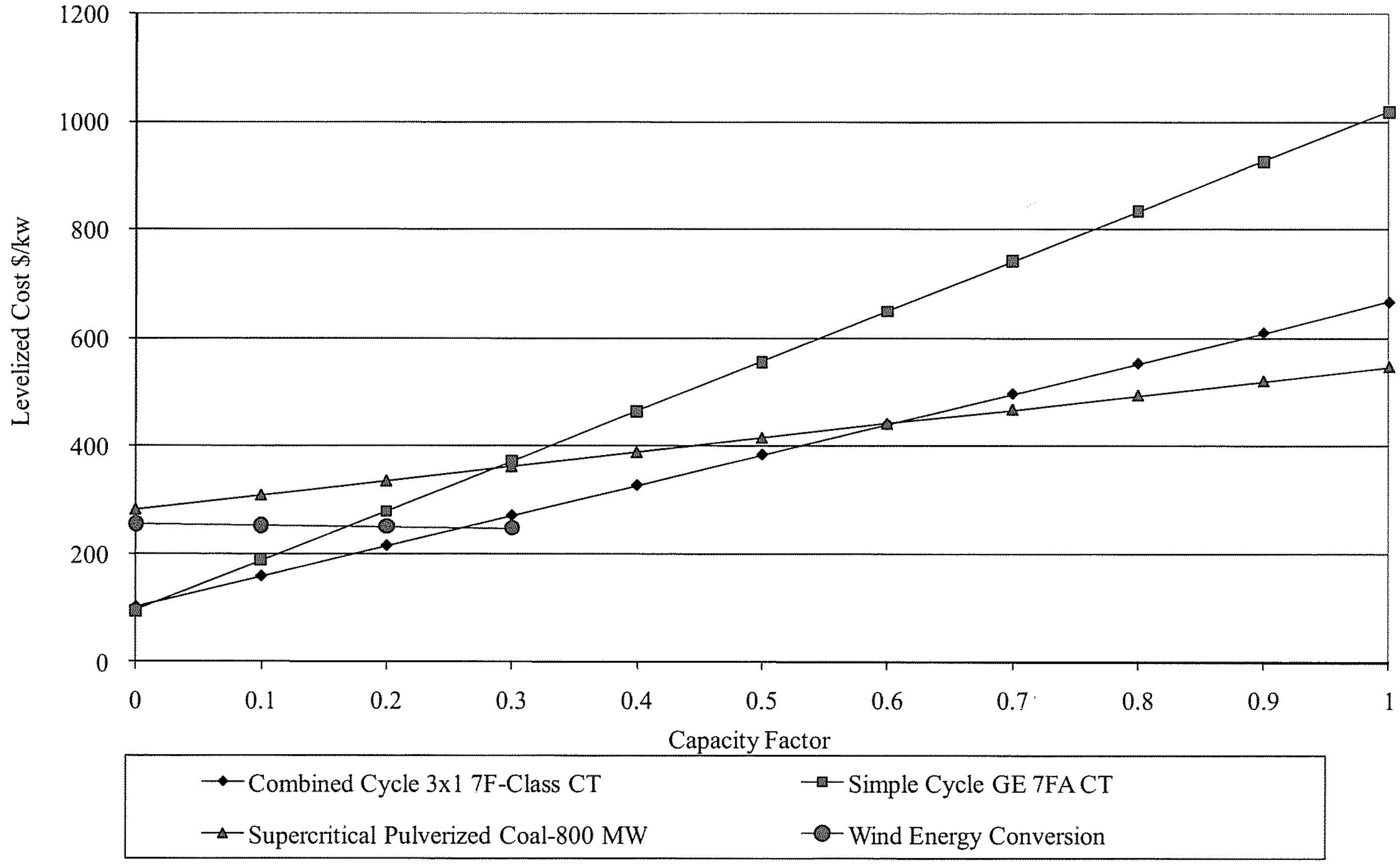
Capital Cost- Base **2010 ($/kW-yr)**
Heat Rate- Base
Fuel Forecast- Base **Capacity Factors**

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage	186	227	268	----	----	----	----	----	----	----	----
Advanced Battery Energy Storage	156	204	252	----	----	----	----	----	----	----	----
Compressed Air Energy Storage	145	208	271	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT	142	239	337	435	532	630	728	825	923	1021	1119
Simple Cycle GE 7EA CT	115	234	352	470	588	707	825	943	1061	1179	1298
Simple Cycle GE 7FA CT	95	188	280	373	465	558	650	743	835	928	1020
Combined Cycle GE 7EA CT	209	278	347	416	485	554	623	692	761	830	899
Combined Cycle 1x1 7F-Class	149	206	264	321	378	436	493	550	608	665	722
Combined Cycle 1x1 G-Class CT	127	184	240	297	354	410	467	523	580	636	693
Combined Cycle 2x1 7F-Class CT	109	165	222	279	335	392	448	505	562	618	675
Combined Cycle 3x1 7F-Class CT	102	158	215	271	328	384	441	497	554	610	667
Combined Cycle Siemens 5000F CT	150	211	271	332	392	452	513	573	634	694	754
Humid Air Turbine Cycle CT	138	223	309	394	480	565	650	736	821	907	992
Kalina Cycle CC CT	147	199	251	302	354	405	457	509	560	612	664
Cheng Cycle CT	153	214	276	337	399	461	522	584	645	707	768
Peaking Microturbine	446	596	746	896	1046	1196	1346	1496	1646	1797	1947
Baseload Microturbine	477	597	717	837	957	1077	1197	1317	1437	1557	1677
Subcritical Pulverized Coal - 256 MW	358	384	410	436	462	488	514	540	566	592	618
Subcritical Pulverized Coal - 512 MW	319	345	370	396	422	448	473	499	525	551	576
Circulating Fluidized Bed - 2x250 MW	294	326	358	390	422	454	486	518	550	582	614
Supercritical Pulverized Coal - 565 MW	324	352	379	406	433	460	488	515	542	569	596
Supercritical Pulverized Coal-800 MW	284	310	336	363	389	415	442	468	494	521	547
Pressurized Fluidized Bed Combustion	367	392	418	443	469	494	520	545	570	----	----
1x1 IGCC	358	382	406	430	454	477	501	525	549	----	----
2x1 IGCC	399	422	445	469	492	515	539	562	585	----	----
Subcritical Pulverized Coal - 502 MW - CCS	561	598	636	673	710	748	785	823	860	898	935
Circulating Fluidized Bed - CC	502	544	587	629	671	714	756	799	841	883	926
Supercritical Pulverized Coal - 565 MW - CCS	471	512	552	593	633	674	715	755	796	836	877
Supercritical Pulverized Coal - 800 MW - CCS	413	444	475	506	537	568	599	630	661	692	723
1x1 IGCC - CCS	510	538	567	595	624	653	681	710	738	----	----
2x1 IGCC - CC	459	486	513	540	568	595	622	649	676	----	----
Wind Energy Conversion	257	254	251	248	----	----	----	----	----	----	----
Solar Photovoltaic	580	580	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough	655	656	----	----	----	----	----	----	----	----	----
Solar Thermal, Power Tower w Storage	829	829	830	830	----	----	----	----	----	----	----
Solar Thermal, Parabolic Dish	764	764	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver	808	809	810	811	812	812	813	----	----	----	----
Solar Thermal, Solar Chimney	673	673	673	673	----	----	----	----	----	----	----
MSW Mass Burn	1809	1773	1738	1702	1667	1631	1596	1560	----	----	----
RDF Stoker-Fired	1723	1808	1894	1979	2064	2149	2235	2320	2405	----	----
Wood Fired Stoker Plant	493	526	559	592	624	657	690	723	755	----	----
Landfill Gas IC Engine	275	321	367	412	458	504	549	595	640	686	----
TDF Multi-Fuel CFB (10% Co-fire)	514	544	573	602	631	660	690	719	748	777	806
Sewage Sludge & Anaerobic Digestion	735	730	725	720	714	709	704	698	693	688	----
Bio Mass (Co-Fire)	387	410	433	456	479	503	526	549	572	595	619
Wood-Fired CFBC	506	532	558	585	611	637	664	690	716	743	769
Co-Fired CFBC	620	666	713	760	806	853	900	946	993	1039	1086
Molten Carbonate Fuel Cell	267	318	369	420	470	521	572	623	674	724	----
Solid Oxide Fuel Cell	172	222	271	320	370	419	468	518	567	616	----
Spark Ignition Engine	425	498	572	645	719	792	865	939	1012	1086	----
Hydroelectric - New - 30 MW	493	487	482	476	471	----	----	----	----	----	----
Hydroelectric - 50 MW Bulb Unit	434	428	423	418	412	----	----	----	----	----	----
Hydroelectric - 14 MW Kaplans Units	944	938	933	927	922	----	----	----	----	----	----
Hydroelectric - 50 MW Kaplan Unit	532	526	521	516	510	----	----	----	----	----	----
Hydroelectric - 50 MW Propeller Unit	503	498	492	487	481	----	----	----	----	----	----
Minimum Levelized $/kW	**87**	**142**	**191**	**224**	**289**	**338**	**378**	**400**	**422**	**445**	**492**

Figure 8.(5)(c)-3

Least Costly Technologies For Further Analysis

Base Capital, Base Heat Rate, Base Fuel



Note: Although wind energy conversion is shown to be the least cost technology at 30% capacity factor, only 15% of its rated capacity is counted toward reserve margin to account for the unreliability of wind energy.

The technologies shown in Table 8.(5)(c)-3 comprise the final list of technologies suggested for detailed analysis within Strategist®.

Table 8.(5)(c)-3
Technologies Suggested for Analysis
Within Strategist®

Supercritical Pulverized Coal – Large
3x1 Combined Cycle Combustion Turbine
2x1 Combined Cycle Combustion Turbine
1x1 Combined Cycle Combustion Turbine
Wind Energy Conversion
Simple Cycle Combustion Turbine
Landfill Gas Internal Combustion Engine
Ohio Falls Hydro Expansion at Shippingport Island

Resource Optimization

Both the economics and practicality of supply-side and demand-side options are carefully examined in the planning decision-making process in order to develop an IRP which meets customers' expected needs. Following review, if an alternative plan shows economic viability, its operational characteristics and economics are evaluated via a capacity expansion computer program, Strategist®. Strategist® contains several modules which may be executed in various ways to evaluate system resource expansion alternatives. Strategist® is a proprietary computer model which integrates the supply-side, demand-side, and environmental compliance alternatives to produce a ranked number of plans that meet the prescribed reliability criteria.

The Companies continually analyze purchase power opportunities through the RFP process and through participating in the wholesale marketplace on a real-time basis. Because of computer run-time and storage limitations, certain logical constraints were implemented in Strategist®. For example, each technology was reviewed and its earliest possible in-service date was established. With this and other logical constraints in place, a base case appropriate for optimization runs was developed.

The optimal resource strategy is determined based on a minimum expected PVRR criterion over a 30-year planning horizon and subject to certain constraints, including a target reserve margin of 16 percent and unit operating characteristics. As precursors to the optimization process, an independent technology screening analysis was conducted for supply-side alternatives and demand-side management programs were developed as discussed above.

Sensitivities developed around several key areas: load; unit retirements; environmental regulations; capital cost of the coal units; and fuel costs. These sensitivities were evaluated with optimization using Strategist® and provide support for the recommended plan.

A more detailed description of the process can be found in the report titled *2011 Optimal Expansion Plan Analysis* (April 2011) contained in Volume III, Technical Appendix. The resulting plan is recommended for use as the Companies' IRP. It is further recommended that purchased power continue to be reviewed through the RFP process as an option to delay generation construction. The optimal plan through 2025 is shown below in Table 8.(5)(c)-4.

Table 8.(5)(c)-4
Recommended 2011 Integrated Resource Plan

Year	Resource
2011	38 MW DSM Initiatives
2012	58 MW DSM Initiatives
2013	59 MW DSM Initiatives
2014	68 MW DSM Initiatives
2015	61 MW DSM Initiatives
2016	61 MW DSM Initiatives **-797 MW Coal Unit Retirements at Cane Run, Green River, and Tyrone** **907 MW 3x1 Combined Cycle Combustion Turbine**
2017	61 MW DSM Initiatives
2018	58 MW DSM Initiatives **907 MW 3x1 Combined Cycle Combustion Turbine**
2019	58 MW DSM Initiatives
2020	58 MW DSM Initiatives
2021	58 MW DSM Initiatives
2022	58 MW DSM Initiatives
2023	58 MW DSM Initiatives
2024	58 MW DSM Initiatives
2025	58 MW DSM Initiatives **907 MW 3x1 Combined Cycle Combustion Turbine**

Notes:

- DSM initiatives are incremental proposed programs including one program with annual savings that do not accumulate.
- Unit ratings for new units and retirements are summer net ratings.

8.(5)(d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;

In February 2011, the Companies contracted with Astrape Consulting to conduct an optimum planning reserve margin study. Astrape Consulting is based in Birmingham, Alabama and has conducted similar studies for other utilities in the southeastern United States. The study is titled *LG&E and KU 2011 Reserve Margin Study* (April 2011) and can be found in Volume

III, Technical Appendix. The study considers the uncertainty in weather, unit availability, load growth, and the availability of purchase power capacity for import to determine the reserve margin level that best balances reliability and cost. Based on its analysis, Astrape Consulting recommends a target reserve margin range of 15-17 percent. A target reserve margin of 16 percent is used in this IRP.

Astrape Consulting utilized their proprietary Strategic Energy and Risk Valuation Model to model the uncertainty in weather, unit performance, load growth, and the availability of purchase power capacity for import for one calendar year (2016). Other key inputs include the value of unserved energy and the cost of new combustion turbine capacity. Reliability costs (including the cost of unserved energy) were computed over thousands of scenarios and various reserve margin levels (from 8 to 20 percent) to determine how reliability costs decrease as reserves increase. The resulting distribution of reliability costs and the cost of new capacity were utilized to determine the reserve margin level that best balances reliability and cost.

8.(5)(e) Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;

The Companies will continue to develop ways to incorporate uncertainty into their analysis. Also, research will continue with regard to supply-side technologies, both with build and purchase opportunities. Specifically, the Companies plan to continually evaluate the economics of delaying near-term generation construction with economic purchase power opportunities. When possible this analysis will be conducted through the RFP process, which allows for a thorough analysis of current generation costs and purchased power costs.

8.(5)(f) Actions to be undertaken during the 15 years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment; and

The Acid Deposition Control Program was established under Title IV of the CAAA and applies to the acid deposition that occurs when SO_2 and nitrogen oxides NO_x are transformed into sulfates and nitrates and combine with water in the atmosphere to return to the earth in rain, fog or snow. Title IV's purpose is to reduce the adverse effects of acid deposition through a permanent reduction in SO_2 emissions and NO_x emissions from the 1980 levels in the 48 contiguous states. As the CAIR has been implemented in 2009 for NO_x and 2010 for SO_2, further reductions in SO_2 and NO_x have aided in reducing ozone and fine particulate ("$PM_{2.5}$") in the affected regions of the country (including Kentucky). However, with the future implementation of new NAAQS for NO_x, $PM_{2.5}$ and SO_2, future promulgation of CATR and rules covering hazardous air pollutants, requirements of Clean Water Act Section 316(b), potential issuance of effluent guidelines under the Clean Water Act and possible rules requiring the reduction of greenhouse gas emissions, it is certain that significant capital investments will be needed in the future to meet these new requirements.

SO_2

Phase II of the CAAA's Acid Deposition Control Program, described previously in Section 8.(5)(b) under *Clean Air Act Compliance Plan*, established a cap on annual SO_2 emissions of approximately 8.9 million tons by the year 2000. The legislation obtained these SO_2 emission reductions from electric utility plants of more than 25 MW (known as "affected units") through the use of a market-based system of emission allowances. Once allocated, allowances may be used by affected units to cover SO_2 emissions, banked for future use, or sold to others.

Clean Air Interstate Rule (SO_2 portion)

As stated previously in section 8.(5)(b), the CAIR introduced a need for further reduction of SO_2 emissions. However, legal proceedings have found CAIR to be a "fatally-flawed" rule and it was remanded by to EPA for further consideration. Additionally, the court ruling did leave Phase I of CAIR in place until a new rule could be promulgated. CAIR continues to use the cap-and-trade emission allowance program. The Companies retain enough emission allowances to cover the level of emissions that occur. CAIR uses the existing SO_2 allowance allocations that the Companies (and all other utilities impacted by CAIR) have already received under the Acid Rain Program for 2010 through 2034. However, CAIR states affected facilities will surrender allowances at a greater rate than is currently required: on a 2-for-1 within Phase I. One caveat is that pre-2010 Acid Rain Program SO_2 allowances (i.e., banked allowances) retained their full value.

To curtail the need for purchasing SO_2 allowances, the Companies completed construction of FGD equipment on KU's Ghent Units 1, 2[10], 3 and 4 and E.W. Brown Units 1, 2, and 3. Construction was completed at Ghent in 2009 and at E.W. Brown in 2010.

Clean Air Transport Rule (SO_2 portion)

In the summer of 2011, EPA is expected to promulgate its replacement to the CAIR rule called Clean Air Transport Rule. The proposals that have been seen indicate that CATR will have similar reduction targets as CAIR. However those targets will be required to be met on an

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[10] The existing FGD on Ghent 1 was re-configured to Ghent Unit 2 and a new FGD was added to Ghent Unit 1.

earlier time frame. The first compliance year will likely be 2012 (instead of 2015) and additional reduction will likely be required starting in 2014 (instead of 2018). Additionally, the proposals have indicated that a new trading program for SO_2 allowances will be developed. Previously banked allowances will not be used in this new program. Further indications are that this program will have very limited interstate trading abilities.

New National Ambient Air Quality Standards for SO_2

EPA published a final rule on June 22, 2010 to revise the current primary SO_2 NAAQS. The new NAAQS for SO_2 is a 1-hour primary (i.e., health based) SO_2 standard of 75 ppb, based on the three year average of the fourth highest of the 1-hour maximum concentrations. Based on historical 3-hour SO_2 data currently being monitored for the current "secondary" SO_2 NAAQS, it is likely that Jefferson County, Kentucky will be designated in non-attainment of the new standard. EPA issued official guidance on how to make the non-attainment designations on March 24, 2011. States have until June 3, 2011 to submit their designation recommendations. It appears that EPA will allow air dispersion modeling rather than relying solely on ambient air monitoring.

The guidance addresses the preferred modeling procedures that EPA recommends both for identifying nonattainment area boundaries and for demonstrating that areas without violating monitors are in attainment. Without dispersion modeling results to support the attainment designations, most areas in the country are expected to initially be designated as "unclassifiable." As stated above, based on the existing network of SO_2 monitors in Kentucky, only monitors in Jefferson County are currently showing violations for the new NAAQS. Therefore, it is likely that Kentucky will only propose Jefferson County as nonattainment with the rest of the State proposed as unclassifiable

Kentucky must incorporate this new NAAQS into its state implementation plan. Additionally, the SIP must contain a plan to get any non-attainment areas into attainment with the standard by June 2017, meaning controls may be needed by 2016.

In summary, all of these SO_2-related regulations will and have required the Companies to evaluate compliance methodologies and potential options. This document encompasses those evaluations.

NO_x

The Acid Deposition Control Program of NO_x under the CAAA is not an allowance-based program, but instead established annual NO_x emission limitations based on boiler type to achieve emission reductions. NO_x emission reduction controls must be in place when the affected unit is required to meet the NO_x standard. The maximum allowable NO_x emission rates for Phase I are 0.45 lb NO_x /MMBtu for tangentially-fired boilers and 0.50 lb NO_x /MMBtu for dry bottom, wall-fired boilers. For Phase II, the maximum allowable NO_x emission rates are 0.40 lb NO_x /MMBtu for tangentially-fired boilers and 0.46 lb NO_x /MMBtu for dry bottom, wall-fired boilers.

All of KU's affected units complied with the Phase II NO_x reduction requirements through a system-wide NO_x emissions averaging plan (average Btu-weighted annual emission limit). Compliance was achieved through the installation of advanced low NO_x burners on Ghent Units 2, 3 and 4.

All of the LG&E affected units complied with the Phase II NO_x reduction requirements on a "stand-alone" or unit-by-unit NO_x emission limitation basis. All of the LG&E units took advantage of the "early election" compliance option under the NO_x reduction program. EPA allowed "early election" units to use the Phase I NO_x limits, thus avoiding the more stringent Phase II NO_x limits. All of the Companies' generating stations operate below their NO_x compliance obligations.

NO_x SIP Call

The NO_x SIP Call was promulgated under Title I of the CAAA of 1990 to control the formation and migration of ozone resulting from the presence of NO_x in the atmosphere. Title I requires all areas of the country to achieve compliance with the NAAQS for ozone, or ground-level smog. In September 1998, EPA finalized regulations (known as the "NO_x SIP Call") to address the regional transport of NO_x and its contribution to ozone non-attainment in downwind areas. EPA maintained that NO_x emissions from the identified states "contribute significantly" to non-attainment in downwind states and that the SIPs in these states were therefore inadequate and had to be revised. EPA's NO_x SIP Call required 19 eastern states (including Kentucky) and the District of Columbia to revise their SIPs to achieve additional NO_x emissions reductions that EPA believed necessary to mitigate the transport of ozone across the Eastern half of the United States and to assist downwind states in achieving compliance with the ozone standard. The final rule required electric utilities in the 19-state area to retrofit their generating units with NO_x control devices by the ozone season of 2004.

The Companies developed a NO_x SIP Call compliance plan (as outlined in KPSC Case Nos. 2000-386 and 2000-439) which resulted in compliance with the NO_x reduction requirements at the lowest combined capital and O&M life cycle costs across the Companies' generation fleet. The plan implemented NO_x emission reduction technologies on a lowest "\$/ton" of NO_x removed basis, to provide flexibility should regulatory or judicial changes affect the level or the timing of the NO_x reduction required.

In fulfillment of the NO_x SIP Call compliance plan, as mentioned in Section 8(5)(b) under *Clean Air Act Compliance Plan*, NO_x emissions from the Companies coal-fired generating units were reduced through the installation of SCRs on six of the Companies' generating units. Additional NO_x control technologies (including advanced low-NO_x burners and overfire air systems) were also installed on nearly every generating unit in the system to reduce the NO_x formed in the combustion zone of the boiler. Additionally, neural network software was installed on many of the generating units to enable better control of the boiler combustion process.

Clean Air Interstate Rule (NO_x portion)

As mentioned previously in 8.(5)(b), EPA finalized the CAIR on March 10, 2005. However, legal proceedings have found CAIR to be a "fatally-flawed" rule and it was remanded by to EPA for further consideration. Additionally, the court ruling did leave Phase I of CAIR in place until a new rule could be promulgated. Implementation of Phase I of the rule has been performed through a "cap-and-trade" allowance program similar to the NO_x SIP Call regulation. Under CAIR for NO_x, the EPA allocated a predetermined amount of allowances to each state and the states determined how to allocate those to individual affected units. Additionally, emissions began to be counted on a year-round basis (i.e., the annual program) beginning in 2009 in addition to continuing an ozone season program. This meant that controls (i.e., SCRs) have been run on a year-round basis to maintain compliance.

Clean Air Transport Rule (NO_x portion)

In the summer of 2011, EPA is expected to promulgate its replacement to the CAIR rule called Clean Air Transport Rule. The proposals that have been seen indicate that CATR will have similar reduction targets as CAIR. However those targets will be required to be met on an earlier time frame. The first compliance year will likely be 2012 (instead of 2015) and additional reduction will likely be required starting in 2014 (instead of 2018). Additionally, the proposals have indicated that a new trading program for NO_x allowances will be developed. Previous generated allowances will not be used in this new program. Further indications are that this program will have very limited interstate trading abilities.

NAAQS for NO_2

On February 9, 2010, EPA published a final rule which revised the Primary National Ambient Air Quality Standard for nitrogen dioxide ("NO_2"). It became effective on April 12, 2010. EPA adopted a new 1-hour standard of 100 ppb and retained the existing annual average standard of 53 ppb. Based on existing air quality data in Kentucky, all areas are currently well below these standards. However, the new rule stipulated that additional new air quality monitor locations be established. Emphasis is to be placed on locating these monitors near major roadways in large cities where the highest concentrations are expected; but additional monitors to represent community-wide air quality may also be required in large cities.

The immediate potential impact for the Companies is that major new sources or modifications to existing sources will have to demonstrate, through air quality modeling, that they do not cause or contribute to a violation of the standard. EPA is also planning to evaluate whether changes to PSD air quality increments are needed. If so, this could place further limits on the allowable amount of increased emissions from a new or modified source.

Kentucky must incorporate this new NAAQS into its SIP. Additionally, the SIP must contain a plan to get any non-attainment areas into attainment with the standard by June 2017; meaning controls may needed by 2016.

In summary, all of these NO_x-related regulations will and have required the Companies to evaluate compliance methodologies and potential options. This document encompasses those evaluations.

Hazardous Air Pollutants

On May 18, 2005, EPA delisted electric generating units from the list of sources subject to hazardous air pollutant controls under Section 112(c) of the Clean Air Act and promulgated the Clean Air Mercury Rule which established a two phase "cap and trade" program for reduction of mercury emissions from those units. Then, on February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAMR on the grounds that EPA failed to follow the correct procedures for delisting electric generating units from regulation under Section 112(c). In February 2009, EPA decided to drop any further legal proceedings regarding CAMR and began focusing on developing a rule to set MACT standards that would apply to all electric generating units that are major sources of hazardous air pollutants (including mercury, other metals, dioxins and other organic compounds).

In January 2010, EPA submitted an information collection request to the electric generating industry to gather more data (including requesting new emissions testing) to aid in the development of the new MACT standards. On March 16, 2011, EPA proposed the rule for these new MACT standards. As proposed, the regulation places numeric limits on mercury, non-mercury metallic HAPs, and acid gas HAPs emissions. The proposal also sets work practice standards to minimize and reduce HAPs emissions.

EPA will be accepting comments on the rule for a 60-day period following publication in the Federal Register. EPA will take those comments into consideration before finalizing the rule. EPA is under legal obligations to promulgate a final rule by November 16, 2011. The Companies are analyzing the proposed rule for impacts, including the potential need for more emission controls to ensure compliance.

Within the proposed rule, facilities are usually given three (3) years to comply with the new standards. The rule also allows for a petition that would request a one year extension to that deadline. If a rule is promulgated in November 2011, facilities must be in compliance by November 2014 (or November 2015 if the extension is granted). Until such time as the pending rule is published, there will continue to be substantial uncertainty as to future regulation of hazardous air pollutants from electric generating units and what actions the Companies will need to take to control emissions.

New NAAQS for Ozone and PM

Ozone

In 1997, the EPA issued the 8-hour ozone NAAQS as a replacement for the 1-hour ozone standard promulgated in 1979. The standard was designed to protect the public from exposure to ground-level ozone. Ground-level ozone is formed when emissions of NO_x and volatile organic compounds react chemically in the presence of sunlight. The new standard was implemented because EPA had information demonstrating that the 1-hour ozone standard was inadequate for protecting human health.

On April 15, 2004, EPA released Phase I of the implementation rule which included designating eight counties within Kentucky as non-attainment. Those Kentucky Counties included Jefferson, Oldham, Boone, Bullitt, Kenton, Campbell, Boyd and Christian. The classifications took effect on June 15, 2004. On July 5, 2007, EPA approved a re-designation of Jefferson, Oldham, Bullitt and Boyd Counties to attainment status, based on a submittal of improved ambient monitoring data by the Kentucky Division for Air Quality. However, EPA continued to review the effectiveness of the ozone NAAQS.

On March 12, 2008, EPA again lowered the primary standard to 0.075 ppm. Several counties in Kentucky have recent monitoring data that are above that level. EPA was to make final designations in March 2011. However, due to a reconsideration of the standards (i.e., the new proposed standards in January 2010 mentioned below) the designations have not been made. If designations are made, states would then have three years to submit a SIP that incorporates the new NAAQS and plans for bringing all areas into attainment with the standard. It is believed that CAIR (to be replaced by CATR) and other federal regulations along with some proposed local initiatives will help bring those counties into compliance by the attainment deadlines (i.e., 2016). Unfortunately, EPA continued to review the effectiveness of the ozone NAAQS.

On January 7, 2010, EPA proposed an even lower primary ozone standard to a range of 0.060 and 0.070 ppm measured over eight hours. At the same time, EPA proposed a new seasonal secondary standard in the range of 7 to 15 ppm. EPA is planning to name the new standards by the end of July 2011. Once the final standard is picked, non-attainment areas will again be designated. Kentucky will then have three years (i.e., 2014) to submit a SIP incorporating the new NAAQS and plans for brining all areas into attainment with the new standard. Typically, non-attainment areas will have at least three years to obtain attainment status. This issue will continue to be reviewed by the Companies.

Particulate Matter

In 1997, EPA adopted the fine particulate NAAQS, which regulates particulate matter measuring 2.5 micrometers in diameter or smaller ($PM_{2.5}$). To add perspective, the diameter of a single human hair is about 20 times larger than $PM_{2.5}$ (approx. 50 micrometers). In general, $PM_{2.5}$ is generated by automobiles, power plants, and industrial sources, but also includes many naturally-occurring dust-like particulates such as pollen and soot. Some $PM_{2.5}$ comes in the form of sulfates, nitrates and carbon-containing compounds. Additionally, gaseous emissions of SO_2 and NO_x can transform into sulfates and nitrates in the atmosphere.

On April 5, 2005, EPA re-issued the list of non-attainment areas in Kentucky which included Boone, Boyd, Bullitt, Campbell, Jefferson, Kenton, and part of Lawrence counties. This started the clock on the need to revise Kentucky's SIP by April 2008.

However, on September 21, 2006, EPA released a revision to the PM NAAQS with a December 18, 2006 effective date. The primary annual $PM_{2.5}$ standard remained the same ($15 \mu g/m^3$). The primary 24-hour $PM_{2.5}$ standard was lowered from 65 to $35 \mu g/m^3$. The 24-hour $PM_{10-2.5}$ standard was retained at $150 \mu g/m^3$. The annual $PM_{10-2.5}$ standard was revoked. On December 22, 2008, EPA finalized their non-attainment designations for Kentucky which included Boone, Boyd, Bullitt, Campbell, Jefferson, Kenton, McCracken and parts of Muhlenberg and Lawrence counties.

In February 2009, the D.C. Circuit Court of Appeals remanded the new standards back to EPA. As a result, EPA has been working on a proposed revision that is expected in 2011. Of additional note, in October 2009, EPA re-designated all counties in Kentucky as attainment with the 24-hour standard, based on a re-evaluation of monitoring data performed and submitted by the Kentucky Division for Air Quality.

As usual, the potential new standards could lead to regulations that may impact the Companies by establishing even stricter emission standards, particularly SO_2 and NO_x. However, the application of emission control equipment and control measures required by other regulations could have the potential to assist non-attainment areas in gaining attainment status without the need to apply even more controls on the Companies' facilities.

Clean Air Visibility Rule

In April 1999, EPA issued final regulations known as the Clean Air Visibility Rule (CAVR, formerly known as the Regional Haze Rule) to protect 156 pristine (Class I) areas of the U.S., which are primarily national parks and wilderness areas. The goal of the regulatory program is to achieve natural background levels of visibility, that is, visibility unimpaired by manmade air pollutants in Class I areas, by 2064. Kentucky has one designated Class I area, Mammoth Cave National Park, and is required to assess visibility impacts to this area.

CAVR gives states flexibility in determining reasonable progress goals for the areas of concern, taking into account the statutory requirements of the CAAA. The final regulation requires all 50 states to reduce emissions of fine particulate matter and other air pollutants, including SO_2 and NO_x, and any other pollutant that can, via airborne transport, travel hundreds of miles and affect visibility in Class I areas. Incremental improvements of visibility in the affected areas are required to be seen early in the next decade.

In June 2001, the EPA proposed guidelines on what constituted Best Available Retrofit Technology ("BART") for the reduction of regional haze issues. The BART requirement applies to all facilities built between 1962 and 1977 that have the potential to emit more than 250 tons per year of visibility-impairing pollution. The guidelines are to be used by the states to determine how to set air pollution limits for facilities in 26 source categories, including power plants. EPA's guidance was remanded back to the agency by the D.C. Circuit to eliminate from the source categories those emission points whose contribution to visibility impairment is negligible. On May 5, 2004, new step-by-step guidance was published for states to implement the rule.

The emissions from the Companies affected units were evaluated for their potential visibility impact on affected Class I areas. From that data, Mill Creek Units 1-4 were the only units identified as having a significant visibility impact. Following an engineering analysis, it was determined that current plans for control technology installations would meet the requirements for BART.

This data along with all other affected facilities information was submitted to the Kentucky Division for Air Quality. They submitted a CAVR SIP in December 2007 to EPA and the National Park Service. Subsequently, KDAQ submitted a revision to the SIP on May 27, 2010. Final approval of the SIP is still pending. Affected facilities typically have three years to comply with SIP requirements once approved.

Additionally, CAVR contains review time periods in which an evaluation is made on progress toward meeting the 2064 goal. Within the review period (15 years) of this report, a review of the progress will be made in 2018. Depending on that analysis, further steps may be taken by regulators to ensure the 2064 goal can be met.

Clean Water Act – Section 316(b)

The Clean Water Act section 316(b) requires the reduction of adverse environmental impact upon aquatic populations by using BACT for water withdrawn from a water source for cooling purposes. In July 2004, EPA's issued a rule for the utility industry which included two "performance standards" requiring facilities to reduce deaths of aquatic life from impingement by 80-95% and for some facilities, also reduce entrainment of fish, eggs and larvae by 60-90%. The regulation was challenged by environmental groups as not strong enough to protect aquatic populations and was ultimately struck down by the U.S. 2nd Circuit Court in 2007. EPA rescinded the rule on January 6, 2008 and began drafting a new set of regulations.

EPA proposed the new rule on March 28, 2011 and is anticipating a final rule by July 2012. The Companies expect both industry and environmental groups will utilize the court system to again challenge the new rule and possibly delay implementation deadlines. The regulations will address both impingement and entrainment issues, thus affecting the Companies facilities, including those already equipped with closed cycle cooling (cooling towers).

Possible requirements within the rule include: cooling towers on all active units, "helper" towers on once-thru cooling units for use during spawning season and low flow periods, fine mesh screens (1-2 mm) for water intake, fish return systems associated with the screens, and/or annual in-stream fish studies. These potential capital investments could be required within the time period of this IRP document. The Companies will continue to review this issue.

Clean Water Act – Effluent Guidelines

In August 2005, EPA proposed a plan to review the effluent guidelines for the steam electric industrial category. EPA determined that the steam electric industry: (1) discharged the highest "toxic weighted pounds equivalent" of the 55 industries with existing guidelines based on National Pollution Discharge Elimination System data, and (2) ranked fourth for toxic loadings based on Toxic Release Inventory data. These rankings along with the advanced age of the steam electric guidelines (last updated in 1982) mean the industry remains a significant target for guidelines revision.

On December 20, 2006, the final version of the effluent guideline plan did not name the steam electric industry for revision. However, a two-year study (2007-2008) was proposed to determine if the guidelines for particular areas should be revised. The areas of interest include cooling water, ash handling, coal pile runoff, air pollution control devices and other miscellaneous waste streams.

In October 2009, EPA determined that it would revise the steam-electric industry standards. In June 2010, EPA issued a very detailed questionnaire to over 500 utilities across the nation that was aimed at assisting EPA in revising the standards. Based on the depth of the questionnaire, it is anticipated that it will take EPA several years to digest the information. Proposed draft regulations are not expected until 2012 with potential promulgation in late 2013. Those potential regulations could require capital investments for treatment facilities within the time period of this IRP document. The Companies will continue to review this issue.

Greenhouse Gases

On September 22, 2009, EPA issued its mandatory GHG emissions reporting rule. Facilities with carbon dioxide equivalent ("CO_2e") of more than 25,000 metric tons or an aggregated maximum rated heat input capacity of more than 30 MMBtu/hr are to begin reporting emission values to EPA by September 30, 2011. Sources required to report include: power plants, miscellaneous stationary combustion sources, and emissions pertaining to the gas supplied to customers of the Companies. On November 2, 2010, the reporting regulation was expanded to include reporting of SF_6 emissions from electric transmission and distribution equipment and methane, carbon dioxide and nitrogen oxide emissions from natural gas processing plants, natural gas transmission compression operations, natural gas underground storage and natural gas distribution activities. Reporting for these activities will begin in March 2012.

On March 13, 2010, EPA issued the greenhouse gas "Tailoring Rule" which became effective on January 2, 2011. This rule sets thresholds for requiring permitting of greenhouse emissions. Between January 2011 and June 2011, sources subject to any other PSD rule that undergo modification will have to get a permit for any applicable GHG emissions if they total more than 75,000 tons per year ("tpy") CO_2e. From July 2011 to June 2013, the threshold will be 100,000 tpy CO_2e for new sources and 75,000 tpy CO_2e for modified sources. EPA is considering lowering the threshold to 50,000 tpy CO_2e for July 2013 and beyond. Therefore, future evaluations of major projects will be required to evaluate whether they trigger the need to perform BACT evaluations of GHG emissions. GHG BACT is expected to be developed over time, but initially will focus primarily on energy efficiency until other options become available and feasible.

In December 2010, EPA also announced that they plan to propose NSPS regulations for GHG emissions from power plant by July 26, 2011 with potential finalization to occur in May 2012. These new rules would set emission requirements for new and modified EGUs and set guidelines for existing EGUs. EPA has indicated that they will coordinate these rules with other rules due out near the same time (i.e., hazardous air pollutants, Clean Air Transport Rule). But until more information is provided, the potential impact of these rules is uncertain. The Companies will continue to review this issue.

Coal Combustion Residuals

Within the next few years, regulatory changes are expected in the permitting and management practices for CCR from coal ash and FGD systems whether they are managed in ash treatment basins (ash ponds) or landfills. Historically, water discharges have influenced CCR management strategies at company facilities. Additional restrictions will likely be placed on discharges permitted by the Kentucky Pollutant Discharge Elimination System from either impoundments or landfills surface runoff (and may also address groundwater monitored aquifers).

In June 2010, EPA published a co-proposal requesting comments on two different approaches for the management of CCRs from coal-fired electric utilities. The first option would manage CCRs as hazardous waste under RCRA Subtitle C and require federal oversight with no use of surface ponds for containment. The second option would manage CCRs as a non-hazardous solid waste under RCRA Subtitle D with state oversight of federal minimum standards. Lined surface impoundments or lined contained landfills could be used in the second option.

EPA will likely select a final option and publish the regulations in late 2011. When published, the regulation will likely have a five year implementation window. This means that existing facilities would require upgrade or closure. The Companies will continue to review this issue.

8.(5)(g) Consideration given by the utility to market forces and competition in the development of the plan.

In the development of the 2011 IRP, the Companies considered market forces and competition. This consideration is reflected in the appropriate sections of the IRP.

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9. FINANCIAL INFORMATION

Table 9 provides the present (base year) value of revenue requirements stated in dollar terms for the 2011 integrated resource acquisition plan and the nominal and real revenue requirements (in $millions). The average rate for each of the forecast years included in the plan is defined as the nominal revenue requirements divided by the total system energy requirements (in ¢/kWh) and is also included in Table 9.

The discount rate used in present value calculations is 6.71 percent. This value is the combined Company after-tax incremental weighted average cost of capital.

Table 9

Kentucky Utilities Company and Louisville Gas & Electric Company

Resource Assesment and Acquisition Plan

Financial Information

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	**Present Value of Revenue Requirements ($ million)**	[redacted]														
2	**Discount Rate**	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%
	Inflation Rate	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
	Real Value of Revenue Requirements ($ million)	[redacted]														
3	**Nominal Value of Revenue Requirements ($ million)**	[redacted]														
4	**Average Rate (Cents/kWh)**	[redacted]														

Notes:
1. Present Value and Real Value Revenue Requirements are in 2010$.
2. Average Rate is Nominal Value of Revenue Requirements divided by total Energy Requirements from Table 8.(4)(b).
3. Inflation Rate is average Global Insight inflation rate from 2011 through 2017.
4. Present Value is nominal value discounted at the discount rate. Real value is the nominal valued discounted at the inflation rate.