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RECEIVED
APR 21 2008
PUBLIC SERVICE COMMISSION

April 21, 2008

RE: The 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company
Case No. 2008-00148

Dear Ms. Stumbo:

Pursuant to 807 KAR 5:058, Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) hereby file the 2008 Joint Integrated Resource Plan (IRP) of LG&E and KU.

Accompanying the IRP filing is a Petition for Confidential Protection relating to projected power production costs and projected sales rates. Therefore, the Companies are filing with the Commission ten (10) bound copies and one (1) unbound copy from which the information sought for confidential treatment has been redacted. Another copy is filed highlighting the information for which confidential treatment is sought.

Sincerely,

Rick E. Lovekamp

Enclosures

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

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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

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3) Section 5. Plan Summary
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1) Recommendations in PSC Staff Report on the Last IRP Filing
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6) Transmission Information
7) 2008 Analysis of Reserve Margin Planning Criterion

8) Update to the 2004 SO_2 Compliance Strategy for E.ON U.S. Subsidiaries Kentucky Utilities Company and Louisville Gas and Electric Company

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

David S. Sinclair, VP Energy Marketing

J. Scott Cooke, Manager Generation Planning

Irvin (Irv) Hurst, Manager Energy Efficiency Operations

Sharon L. Dodson, Director Environmental Affairs

Robert F. Thomson, Manager Economic Analysis

Lonnie Bellar, VP State Regulation and Rates

Rick E. Lovekamp, Manager Regulatory Affairs

Allyson Sturgeon, Senior Corporate Attorney

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 E.ON U.S. After more than three successful years as part of E.ON AG (Frankfurt: EOA), LG&E Energy Corp. changed its name to E.ON U.S. LLC effective November 29, 2005, while maintaining the utility brand names of KU and LG&E. 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 Companies' Integrated Resource Planning (IRP) mandate is to meet future energy requirements within its service territory at the lowest possible cost consistent with reliable supply. Serving more than 934,000 electricity customers via a transmission and distribution network covering some 27,000 square miles, KU and LG&E have a joint net summer generation capacity of 7,519 megawatts (MW) as shown in Table 5.(1)-1. Based in Lexington, KU supplies electric service in an area that covers approximately 6,600 non-contiguous square miles and serves 77 counties in Kentucky as well as five counties in southwestern Virginia that are serviced by Old Dominion Power Company (ODP). KU also sells wholesale electricity for resale to 12 municipalities in Kentucky. LG&E, an electric and natural gas utility, serves customers in the

Louisville metropolitan area and sixteen surrounding counties which cover approximately 700 square miles.

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 18 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 for KU and LG&E

Totals	2007 Summer Net Capacity (MW)	2007/8 Winter Net Capacity (MW)
KU Coal	2863	2861
KU CT – Gas	1499	1669
KU Hydro	24	24
Total KU	**4386**	**4554**
LG&E Coal	2418	2440
LG&E CT – Gas	665	738
LG&E Hydro	50	34
Total LG&E	**3133**	**3212**
Coal	5281	5301
CT – Gas	2164	2407
Hydro	74	58
Total	**7519**	**7766**

The Companies' net summer generating capability in 2007 was 7,519 MW. The Companies have purchase agreements in place with Owensboro Municipal Utilities (OMU) and Ohio Valley Electric Corporation (OVEC). The Companies currently receive 8.13 percent of the OVEC capacity and energy. Further description of the OVEC sponsorship is as indicated in Section 5.(4). The Companies' highest combined system peak demand of 7,132 MW occurred on August 9, 2007, at hour ending 16:00 EST. On that date, KU's highest peak demand was 4,344 MW at hour ending 15:00 EST. LG&E experienced its highest system peak demand of 2,834 MW on August 16, 2007, at hour ending 15:00 EST. However, KU superseded its peak on January 25, 2008, at hour ending 08:00 EST with 4, 476 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. This dynamic process continues to evolve and uses state-of-the-art techniques and models as well as timely and pertinent information. 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 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company dated February 2006 (Case No. 2005-00162) 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 its 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 2008 IRP.

Models & Methods

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. 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 2007 was: 85.8 percent Kentucky-retail; 4.7 percent Virginia-retail; and 9.5 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 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 adjusted for company uses and losses. The resulting estimate of monthly energy requirements is then associated with a typical load profile and load factor 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. A coal production forecast is obtained from Hill & Associates for use in modeling KU mine power tariff sales. Itron provides regional databases with information from the Energy Information Administration (EIA) that support 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 KU and LG&E. Historical sales data for these customers and for the respective class forecasts are obtained via extracts from KU's and LG&E's Customer Information Systems (CIS). Figure 5.(2)-1 illustrates the external and internal data sources used to drive the KU and LG&E forecasts.

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

External	Internal
Global Insight National Economic/ Demographic Factors	Retail Electric Price Forecast
Global Insight County & State Economic/ Demographic Factors	LG&E/KU Customer and Sales History by Rate Class from CIS
NCDC Temperature Data for Lexington, Louisville, and	Individual Large Customer Information
Hill & Associates Kentucky Coal Production	Service Territory Appliance Saturation Surveys
Itron/EIA Appliance Efficiency & Saturation	Typical Load Profile & Load Factor Assumptions

Key Assumptions

Following is a summary of key assumptions made in Global Insight's 2007 Long-Term Macro Forecast, used by the Companies as macroeconomic background for the energy sales forecast in the 2008 IRP. A copy of this forecast is attached as part of Technical Appendix 3, 'Supporting Documents,' in Volume II.

- *Trend Scenario*: The scenario assumes no major disruptions to the long-term growth trend. The projection is best described as depicting the mean of all possible paths the economy could follow. Economic output is forecast to grow smoothly.

- *Demographics*: The population projection in the trend scenario is consistent with the Census Bureau's latest 'interim' projections which were released in May 2004. Based on specific assumptions about immigration, fertility and mortality rates, U.S. population was forecast to achieve average annual growth of 0.8 percent through 2030.

- *Employment*: Overall employment was forecast to grow at approximately 0.8 percent per year over the forecast period.

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

In addition to national- and state-level data, Global Insight provided county-level economic and demographic forecasts. Service-territory level forecasts were created as an aggregate of the county level forecasts. These forecasts are addressed further in section 5.(3).

Energy Independence and Security Act of 2007

The Energy Independence and Security Act of 2007 (ESA 2007) was signed into law by President Bush in December 2007. The provisions in ESA 2007 are primarily designed to increase energy efficiency and the availability of renewable energy. KU and LG&E electricity sales will be impacted primarily by a set of provisions in the law that tighten lighting and appliance efficiency standards as well as foster the development of new building and commercial equipment standards.

The 2008 IRP incorporates the impact of the new lighting and appliance efficiency standards on electricity sales (new building and commercial equipment standards have not been developed, so the potential impact of these standards has not been incorporated). The new lighting efficiency standards are expected to have the greatest impact on electricity sales. The full impact of the new lighting standards is expected to be phased in gradually between 2012 and 2019. Because KU and LG&E already assume appliances will become more efficient in the future, the impact of the new appliance efficiency standards is not as significant. A more detailed discussion of ESA 2007 and its anticipated impact on electricity sales is included in Section 6.

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, state-of-the-art computer model developed by Ventyx Energy, LLC[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.

Various sensitivity analyses were performed as a part of this detailed resource assessment (see below). The breakeven sensitivities help determine what data input or assumption changes would be necessary in order to make an uneconomical technology in the base case conditions become economically equivalent.

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

[1] Formerly Strategist® was a NewEnergy product. NewEnergy Associates was acquired by Ventyx on 8/31/2007.

- New unit in 2015 must be coal unit
- Higher forecast customer load requirements
- Lower forecast customer load requirements
- Retire Green River units
- Retire Tyrone unit 3
- Retire Green River and Tyrone units
- Retire aging "Group 3" combustion turbines
- No IRP DSM
- No DSM filing approval
- No new DSM
- CO_2 regulation
- Combined cycle operation

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. Another significant factor which influences the Companies' resource plan is the load forecast (demand and energy forecast). Each resource option is selected for optimal performance at specific levels of utilization. Alternative load growth scenarios also 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.

Additionally, the Companies reviewed an "aggressive green" scenario as a sensitivity to the optimal plan. The aggressive green scenario illustrates the impact of "efficiency at all costs" and a national commitment toward eliminating coal generation in favor of renewables. The following is a list of key demand- and supply-side assumptions in the aggressive green scenario:

Demand-side Assumptions

- Consumers purchase the most efficient appliances at normal replacement intervals regardless of cost;
- Incandescent light bulbs phased out by 2012;
- New homes and buildings built to more stringent energy-efficient standards;
- New homes must be constructed with solar photovoltaic technology after 2012;
- Large commercial customers use 20 percent less energy by 2022

Supply-side Assumptions

- Existing coal units must be retired after 50 year life beginning in 2015;
- No new coal units are built without carbon capture and sequestration (CCS);
- Kentucky adopts mandatory Renewable Portfolio Standard (RPS) of 15 percent by year 2020).

Details of this scenario can be found in the report titled *Aggressive Green Scenario* in Volume III, Technical Appendix.

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

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, native electric customers increased from 892,688 in 2003 to 934,227 in 2007, an average annual growth rate of 1.1 percent. Actual sales for KU and LG&E rose from 30,999 GWh in 2003 to 34,300 GWh in 2007, increasing at an average annual growth rate of 2.6 percent. On a weather-normalized basis, average sales growth was 1.7 percent over this period. Combined energy requirements grew from 32,778 GWh in 2003 to 33,387 GWh in 2007. Peak demand fluctuated over the 2003-2007 period. On an actual basis, peak demand fell from 6,393 MW in 2003 to 6,223 MW in 2004 only to increase to 6,833 MW in 2005. Further increases occurred in 2006 and 2007 with recorded peaks of 6,880 MW and 7,132 MW, respectively. On a weather-normalized basis, the system peak increased by an annual growth rate of 2.1 percent from 2003 to 2007.

[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, 2003-2007

	2003	2004	2005	2006	2007
Customers	892,677	903,834	914,352	925,251	934,227
Sales (GWh)	30,999	31,902	33,283	32,641	34,300
Weather-Normalized Sales (GWh)	31,518	32,277	32,709	33,063	33,705
Energy Requirements (GWh)	32,778	33,976	35,377	34,738	36,387
Peak Demand (MW) [1]	6,393	6,223	6,833	6,880	7,132
Weather-Normalized Peak Demand (MW)	6,448	6,362	6,734	7,041	7,011

[1]Reflects impact of interruptible and curtailed loads.

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. In 2007, weather-normalized sales were lower than expected due to delays in certain large expansion projects among the Companies' large industrial customers. This explains the relatively high growth rate in projected sales for 2008 of 3 percent. These projects are expected to resume as the economy recovers. From 2008 to 2010, Combined Company customers are forecast to grow at an average annual rate of 1.3 percent, while both sales and energy requirements are forecast to grow at an average annual rate of approximately 1.5 percent. From 2011 through 2016, Combined Company customers are forecast to grow at an average annual rate of 1.2 percent. After 2016, the average annual growth rate for customers is 1.1 percent.

Combined Company sales and energy requirements are expected to grow at an average annual rate of 1.5 percent over the period between 2008 and 2012. Over the next five-year period (2013-2017), the average annual growth in sales and energy requirements declines to 1.0 percent due primarily to reductions in lighting-related consumption prompted by ESA 2007 (see Section 6 for a more detailed discussion of ESA 2007). Over the entire forecast period, the average annual growth in sales and energy requirements is 1.3 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)[1]	% Growth in Energy Sales	Combined Company Energy Requirements Forecast (GWh)[1]	% Growth in Energy Requirements
2007	934,227		33,705		35,758	
2008	944,906	1.1%	34,731	3.0%	36,835	3.0%
2009	957,148	1.3%	35,267	1.5%	37,404	1.5%
2010	969,313	1.3%	35,754	1.4%	37,921	1.4%
2011	981,218	1.2%	36,328	1.6%	38,531	1.6%
2012	992,836	1.2%	36,843	1.4%	39,080	1.4%
2013	1,004,189	1.1%	37,268	1.2%	39,535	1.2%
2014	1,015,777	1.2%	37,629	1.0%	39,927	1.0%
2015	1,027,618	1.2%	37,967	0.9%	40,298	0.9%
2016	1,039,507	1.2%	38,332	1.0%	40,695	1.0%
2017	1,051,341	1.1%	38,761	1.1%	41,153	1.1%
2018	1,063,311	1.1%	39,298	1.4%	41,725	1.4%
2019	1,075,417	1.1%	39,812	1.3%	42,270	1.3%
2020	1,087,662	1.1%	40,418	1.5%	42,914	1.5%
2021	1,100,047	1.1%	40,923	1.2%	43,449	1.2%
2022	1,112,574	1.1%	41,477	1.4%	44,036	1.4%

[1] 2007 sales and energy requirement figures are weather-normalized actual values.

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 7,095 MW in 2008 to 7,512 MW in 2012, a growth of 417 MW with an average annual growth rate of 1.4 percent. By 2022, Combined Company demand reaches 8,591 MW for a total increase from 2008 of 1,496 MW, with growth averaging 1.4 percent per year over the full forecast period. Combined Company curtailable load is estimated to be 105 MW for each summer period during the forecast. From 2008 through 2012, the winter peak increases by 342 MW for an average growth rate of 1.4 percent. By 2022, the winter peak is forecast to increase by 1,138 MW with growth averaging 1.2 percent per year. The forecast of winter peak demands is not adjusted for curtailable loads.

Some of the variability in the growth in the Combined Company winter peak demand is driven by the selection of the historical "reference months" that are used to sort hourly loads in chronological order. These reference months reflect the fact that the winter seasonal peaks for KU and LG&E are significantly less coincident than the summer seasonal peaks. Please see Technical Appendix, *Hourly Demand Forecast Methodology*, in Volume II for a more detailed discussion of the methodology used to produce the hourly demand forecast.

Table 5.(3)-3
Combined Company Seasonal Peak Demand Forecast

Year	Combined Company Summer Peak Demand (MW) [1,2]	Percent Growth	Year	Combined Company Winter Peak Demand (MW) [1]	Percent Growth
2007	7,011		2007/08	6,244	
2008	7,095	1.2%	2008/09	6,055	-3.0%
2009	7,188	1.3%	2009/10	6,108	0.9%
2010	7,280	1.3%	2010/11	6,241	2.2%
2011	7,404	1.7%	2011/12	6,322	1.3%
2012	7,512	1.5%	2012/13	6,397	1.2%
2013	7,600	1.2%	2013/14	6,447	0.8%
2014	7,707	1.4%	2014/15	6,492	0.7%
2015	7,812	1.4%	2015/16	6,517	0.4%
2016	7,912	1.3%	2016/17	6,638	1.8%
2017	8,012	1.3%	2017/18	6,733	1.4%
2018	8,127	1.4%	2018/19	6,898	2.4%
2019	8,226	1.2%	2019/20	6,903	0.1%
2020	8,364	1.7%	2020/21	6,975	1.0%
2021	8,461	1.2%	2021/22	7,110	1.9%
2022	8,591	1.5%	2022/23	7,193	1.2%

[1] 2007 summer and winter peak demands are weather-normalized actual values.
[2] Summer peak demand forecast does not reflect an estimated 126 MW reduction in peak demand associated with existing DSM programs.

The 2007/08 winter peak occurred on January 25, 2008 after the winter peak demand forecast had been finalized. The actual 2007/08 weather-normalized winter peak demand (6,244 MW) is higher than the 2007/08 forecasted value and higher than forecasted values through the winter of 2010/11. KU and LG&E conducted an end-use residential survey in the summer of 2007. According to the survey results, the penetration of electric heating in the KU and LG&E service territories is increasing. Most notably, whereas approximately 43 percent of all single family homes in the KU service territory have electric heating, roughly 83 percent of single-family homes constructed between 2002 and 2006 have electric heating. This increase in electric heating load is suspected to be driving the higher than expected winter peak demand. The Companies will continue to monitor this situation and adjust future winter peak demand forecast accordingly.

Kentucky Utilities Company

History

From 2003 to 2007, KU calendar sales grew at an average annual rate of 2.6 percent on an actual basis and 2.0 percent on a weather-normalized basis. On an actual basis, recent growth has been most pronounced in the Residential class (3.6 percent on average since 2003) followed by the Commercial (3.3 percent), Public Authorities (2.1 percent), and Industrial (2.0 percent) classes. Virginia retail sales have remained relatively flat from 2003 through 2007. Calendar sales by class (not weather-normalized) and recorded and weather-normalized total sales are displayed in Table 5.(3)-4.

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

	2003	2004	2005	2006	2007
SYSTEM BILLED SALES:					
Recorded	19,470	20,074	20,994	20,831	21,625
Weather-Normalized	19,702	20,458	20,752	21,013	21,392
SYSTEM USED SALES:					
Recorded	19,496	20,178	20,990	20,675	21,643
Weather-Normalized	19,803	20,534	20,769	20,927	21,437
ENERGY REQUIREMENTS:					
Recorded	20,654	21,317	22,354	22,014	22,993
Weather-Normalized	20,961	21,673	22,119	22,282	22,774
SALES BY CLASS:					
Residential	5,594	5,762	6,178	5,908	6,432
Commercial	4,016	4,130	4,276	4,270	4,577
Industrial	5,594	5,880	6,004	6,083	6,049
Lighting	54	54	52	52	54
Public Authorities	1,428	1,466	1,514	1,472	1,552
Requirement Sales for Resale	1,903	1,959	2,014	1,978	2,059
	---------	---------	---------	---------	---------
KENTUCKY Retail	18,589	19,252	20,038	19,764	20,723
VIRGINIA Retail	906	926	952	910	919
System Losses	1,129	1,115	1,348	1,323	1,333
Utility Use	30	24	16	16	17
ENERGY REQUIREMENTS	20,654	21,317	22,354	22,014	22,993

KU Forecast

KU's long-term economic and demographic forecast drivers are provided by Global Insight. Service-territory specific forecasts were created as an aggregate of county-level forecasts.

Key Economic and Demographic Assumptions

- *Demographics:* The population growth rate in the KU service territory was forecast to be below the national average. Annual population growth was forecast to average 0.6 percent over the next 10 years in the KU service territory and 0.8 percent nationally. This is a continuation of past trends where population growth in Kentucky has lagged the national average. The number of households was forecast to increase at a slightly higher rate (0.7 percent per year on average over the next 10 years). The higher growth in the number of households is the result of a declining trend in the forecast of the number of persons per household.

- *Output:* Real Gross State Product (RGSP) for the state of Kentucky was forecast to grow by approximately 2.5 percent annually over the forecast period.

- *Employment:* Overall employment was forecast to grow at approximately 0.8 percent per year over the forecast period.

- *Personal Income:* Real total personal income in the KU service territory was forecast to grow at a 2.6 percent average annual rate for the first 10 years, and at 2.0 percent annually over the next 10 years.

KU Customer Growth and Energy Sales

Total KU energy sales are expected to grow at an average annual rate of 1.5 percent over the first five years of the forecast period (2008-2012). Over the entire forecast period (2008-2022), sales are expected to grow at an average annual rate of 1.3 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 2007 sales.

Kentucky retail residential sales are forecast to increase at a 1.4 percent annual rate from 2008 to 2012. Residential growth is driven by a combination of customer growth and continued growth in use-per-customer. Kentucky retail commercial sales are forecast to increase at a 1.5 percent annual rate from 2008 to 2012, while Kentucky retail industrial sales are projected to average 1.7 percent growth. Strong growth by some of the larger industrial customers creates a relatively strong medium-term growth outlook for the industrial and public authority sectors. Wholesale sales are forecast to grow at an average rate of 1.1 percent, generally in line with but slower than Kentucky retail sales. Virginia sales are expected to increase only moderately, with 0.9 percent average growth.

Table 5.(3)-5
KU: Sales Structure and Forecast Growth Rates By Class

Class	Percent of 2007 Sales	Percent Annual Growth Rate 2008-2012	Percent Annual Growth Rate 2008-2022
Kentucky	**85.8%**	1.6%	1.3%
Residential	34.5%	1.4%	1.3%
Commercial	24.5%	1.5%	1.5%
Industrial	32.4%	1.7%	1.3%
Public Authorities	8.3%	2.1%	1.8%
Lighting	0.3%	1.5%	1.4%
Virginia	**4.7%**	0.9%	0.7%
TOTAL RETAIL	**90.5%**	1.6%	1.4%
WHOLESALE	**9.5%**	1.1%	1.0%
TOTAL COMPANY	**100%**	1.5%	1.3%

KU's forecast of total customers and energy sales is summarized in Table 5.(3)-6. In 2007, weather-normalized sales were lower than expected due to delays in some large expansion projects among KU's large industrial customers. This explains the relatively high growth rate in projected sales for 2008 of 3.3 percent. From 2008-2012 sales are projected to grow at an average growth rate of 1.5 percent. Over the next five-year period (2013-2017), the average annual growth in sales is reduced to 1.1 percent due primarily to reductions in lighting-related consumption prompted by ESA 2007 (see Section 6 for a more detailed discussion of ESA

2007). Through the entire forecast horizon, sales are projected to grow at an annual rate of 1.3 percent.

Table 5.(3)-6
Total KU Customer and Calendar Sales Forecasts (GWh)

Year	Customers	% Growth in Customers	Baseline Energy Sales Forecast (GWh)[1]	% Growth in Energy Sales
2007	533,524		21,437	
2008	536,888	0.6%	22,141	3.3%
2009	543,524	1.2%	22,494	1.6%
2010	550,149	1.2%	22,823	1.5%
2011	556,700	1.2%	23,192	1.6%
2012	563,341	1.2%	23,519	1.4%
2013	570,054	1.2%	23,775	1.1%
2014	576,840	1.2%	23,998	0.9%
2015	583,448	1.1%	24,252	1.1%
2016	589,964	1.1%	24,512	1.1%
2017	596,501	1.1%	24,799	1.2%
2018	603,111	1.1%	25,163	1.5%
2019	609,795	1.1%	25,504	1.4%
2020	616,554	1.1%	25,918	1.6%
2021	623,388	1.1%	26,252	1.3%
2022	630,298	1.1%	26,623	1.4%

[1]2007 energy sales figure is a weather-normalized actual value.

KU Peak Demand

KU's actual and weather-normalized peak demand from 2003 to 2007 are shown in Table 5.(3)-7. On a weather-normalized basis and after curtailment, KU's summer and winter peaks in 2003 were 3,836 MW and 3,930 MW respectively. In 2007, the weather-normalized summer peak was 4,236 MW. The weather-normalized KU winter peaks have ranged from 3,771 MW in 2003/04 to 4,353 MW in 2006/07.

Table 5.(3)-7
KU Recorded and Weather-Normalized Peak Load (MW)

	2003	2004	2005	2006	2007
SUMMER					
Recorded	3,810	3,744	4,079	4,207	4,344
Weather-Normalized	3,836	3,800	4,049	4,257	4,236
	2002/03	**2003/04**	**2004/05**	**2005/06**	**2006/07**
WINTER					
Recorded	3,944	3,768	4,065	4,019	4,300
Weather-Normalized	3,930	3,771	4,059	4,114	4,353

KU Peak Demand Forecast

The KU summer peak demand is forecast to increase at an average annual rate of 1.4 percent from 4,306 MW in 2008 to 5,223 MW in 2022, adding 917 MW over the period at an average of 66 MW per year (see Table 5.(3)-8). From 2008 to 2012, the KU summer peak demand is forecast to increase from 4,306 MW to 4,560 MW, which represents an average annual growth of 1.4 percent. From 2012 to 2022, the summer peak demand is forecast to increase at an average annual rate of 1.4 percent from 4,560 MW to 5,223 MW, adding 663 MW over the period at an average of 66 MW per year. KU's curtailable load is estimated to be 50 MW for each summer period during the forecast. Because lighting is utilized primarily in the morning and evening hours and the KU summer peak typically occurs in the afternoon, ESA 2007 does not impact the forecast of peak demand between 2013 and 2018 as significantly as the forecast of sales.

Table 5.(3)-8
KU: Forecast Energy Requirements (GWh) and Peak Demand (MW)

Year	Energy Requirements (GWh)[1]	Percent Growth	Summer Peak (MW)[1,2]	Percent Growth
2007	22,774		4,236	
2008	23,514	3.2%	4,306	1.7%
2009	23,889	1.6%	4,371	1.5%
2010	24,239	1.5%	4,428	1.3%
2011	24,631	1.6%	4,496	1.5%
2012	24,981	1.4%	4,560	1.4%
2013	25,255	1.1%	4,615	1.2%
2014	25,497	1.0%	4,669	1.2%
2015	25,774	1.1%	4,736	1.4%
2016	26,055	1.1%	4,799	1.3%
2017	26,362	1.2%	4,861	1.3%
2018	26,749	1.5%	4,933	1.5%
2019	27,112	1.4%	5,001	1.4%
2020	27,552	1.6%	5,082	1.6%
2021	27,906	1.3%	5,149	1.3%
2022	28,300	1.4%	5,223	1.4%

[1]The 2007 figures are weather-normalized actual values.
[2]Summer peak demand forecast includes an estimated 50 MW reduction for curtailable loads. It does not include a 57 MW reduction associated with existing DSM programs.

Louisville Gas and Electric Company

History

From 2003 to 2007, LG&E calendar sales grew at an average annual growth rate of 2.4 percent on an actual basis and 1.2 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 (4 percent on average since 2003) followed by the small commercial (3.1 percent), public authorities (2.1 percent), and large commercial (2.1 percent) classes. Calendar sales by class (not weather-normalized) and recorded and weather-normalized total sales are displayed in Table 5.(3)-9.

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

	2003	2004	2005	2006	2007
SYSTEM BILLED SALES:					
Recorded	11,448	11,698	12,186	12,010	12,669
Weather-Normalized	11,655	11,735	11,965	12,151	12,198
SYSTEM USED SALES:					
Recorded	11,503	11,724	12,292	11,965	12,658
Weather-Normalized	11,715	11,744	11,940	12,136	12,268
ENERGY REQUIREMENTS:					
Recorded	12,123	12,480	13,022	12,724	13,395
Weather-Normalized	12,335	12,500	12,650	12,905	12,984
SALES BY CLASS:					
Residential	3,835	3,924	4,265	4,018	4,486
Small Commercial	1,263	1,282	1,333	1,319	1,428
Large Commercial	2,219	2,251	2,349	2,295	2,409
Industrial	2,936	3,019	3,077	3,068	2,992
Public Authorities	1,181	1,179	1,204	1,205	1,282
Lighting	69	69	64	61	60
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TOTAL LG&E SALES	11,503	11,724	12,292	11,965	12,658
System Losses	620	756	679	744	751
Utility Use	22	24	24	23	24
ENERGY REQUIREMENTS	12,123	12,480	13,022	12,724	13,395

LG&E Forecast

Like KU, LG&E's long-term economic and demographic forecast drivers are provided by Global Insight. Service-territory specific forecasts were created as an aggregate of county-level forecasts.

Key Assumptions

- *Demographics:* Population in the Louisville area was forecast to increase at a slower rate than the national population forecast. Annual population growth was forecast to average 0.7 percent over the next five years as well as over the 15-year forecast horizon. Furthermore, with the aging of the population (resulting in fewer persons per household), households numbers were forecast to increase at a faster rate than population – 1.1 percent per year on average over the next five years and 1 percent over the full 15-year forecast horizon.

- *Output:* Real Gross State Product (RGSP) for the state of Kentucky was forecast to grow by approximately 2.5 percent annually over the forecast period. Although LG&E's service territory is small geographically relative to the state, large employers in the service territory are significant contributors to the index.

- *Employment:* Overall employment was forecast to grow at approximately 0.7 percent per year over the forecasted period.

- *Personal Income:* Real total personal income was forecast to increase at a 2.9 percent average annual rate over the first five years and at a 2.8 percent growth rate over the 15-year forecast horizon.

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 2007 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 2.1, 1.6 and 1.4 percent respectively. Over the 15-year period,

sales to the large commercial sector continue to have the highest sustained growth at 2 percent, followed by public authority and small commercial at 1.4 percent. Industrial sales are projected to increase at an average annual rate of 0.3 percent for the 2008-2022 period. The higher growth rate in the large commercial class is primarily the result of planned expansions by one large customer in that class.

Table 5.(3)-10
LG&E: Sales Structure and Forecast Growth Rates by Class

Class	Percent of 2007 Sales	Percent Annual Growth Rate 2008-2012	Percent Annual Growth Rate 2008-2022
Residential	35%	1.4%	1.2%
Small Commercial	11%	1.6%	1.4%
Large Commercial	19%	2.3%	2.0%
Industrial	24%	0.5%	0.3%
Public Authority	10%	2.1%	1.4%
Lighting	0%	0.5%	0.5%
LG&E Total	100%	1.4%	1.2%

Like KU (but to a lesser extent), LG&E's weather-normalized sales in 2007 were lower than expected due to lower than expected sales to its industrial class. This explains the relatively high growth rate in projected sales for 2008 of 2.6 percent. Total LG&E energy sales from 2008-2012 are forecast to rise at an annual average rate of 1.4 percent. Over the next five-year period (2013-2017), the average annual growth in sales is reduced to 0.9 percent due primarily to reductions in lighting-related consumption prompted by ESA 2007 (see Section 6 for a more detailed discussion of ESA 2007). Over the 15-year forecast horizon, total sales are forecast to grow at an annual average rate of 1.1 percent. Table 5.(3)-11 summarizes LG&E's forecast of total customers and sales with their corresponding annual growth rates through 2022.

Table 5.(3)-11
LG&E: Forecast Customer Numbers and Calendar Sales (GWh)

Year	Customers	% Growth in Customers	Energy Sales Forecast (GWh)[1]	% Growth in Energy Sales
2007	400,703		12,268	
2008	408,018	1.8%	12,590	2.6%
2009	413,623	1.4%	12,773	1.4%
2010	419,163	1.3%	12,931	1.2%
2011	424,518	1.3%	13,136	1.6%
2012	429,495	1.2%	13,324	1.4%
2013	434,135	1.1%	13,493	1.3%
2014	438,937	1.1%	13,631	1.0%
2015	444,170	1.2%	13,714	0.6%
2016	449,543	1.2%	13,820	0.8%
2017	454,840	1.2%	13,962	1.0%
2018	460,200	1.2%	14,135	1.2%
2019	465,622	1.2%	14,308	1.2%
2020	471,109	1.2%	14,500	1.3%
2021	476,660	1.2%	14,671	1.2%
2022	482,276	1.2%	14,854	1.2%

[1]2007 energy sales figure is a weather-normalized actual value.

LG&E Peak Demand

As shown in Table 5.(3)-12, LG&E's summer peak demand in 2007 (after curtailment) was 2,834 MW. On a weather-normalized basis (and after curtailment), LG&E's peak demand in 2007 was 2,775 MW.

Table 5.(3)-12
LG&E Recorded and Weather-Normalized Peak Load (MW)

	2003	**2004**	**2005**	**2006**	**2007**
SUMMER					
Recorded	2,583	2,485	2,754	2,729	2,834
Weather-Normalized	2,612	2,562	2,685	2,784	2,775
	2002/03	**2003/04**	**2004/05**	**2005/06**	**2006/07**
WINTER					
Recorded	1,824	1,750	1,787	1,817	1,885
Weather-Normalized	1,818	1,683	1,815	1,838	1,891

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 1.4 percent from 2,789 MW in 2008 to 3,368 MW in 2022, adding 579 MW over the period at an average of 41 MW per year. Between 2008 and 2012, the summer peak demand is forecast to increase at an average annual rate of 1.4 percent from 2,789 MW to 2,952 MW, adding 163 MW over the four-year period at an average of 41 MW per year. For the 2012 to 2022 time period, the summer peak demand is projected to increase at an annual rate of 1.3 percent from 2,952 MW to 3,368 MW. LG&E's curtailable load is estimated to be 55 MW for

each summer period during the forecast. Because lighting is utilized primarily in the morning and evening hours, ESA 2007 does not impact the forecast of peak demand between 2013 and 2018 as significantly as the forecast of sales.

Table 5.(3)-13
LG&E: Forecast Energy Requirements and Peak Demand

Year	Energy Requirements (GWh)[1]	Percent Growth	Summer Peak (MW)[1,2]	Percent Growth
2007	12,984		2,775	
2008	13,321	2.6%	2,789	0.5%
2009	13,514	1.5%	2,817	1.0%
2010	13,682	1.2%	2,862	1.6%
2011	13,900	1.6%	2,908	1.6%
2012	14,099	1.4%	2,952	1.5%
2013	14,280	1.3%	2,995	1.5%
2014	14,430	1.0%	3,038	1.4%
2015	14,524	0.7%	3,075	1.2%
2016	14,640	0.8%	3,113	1.2%
2017	14,791	1.0%	3,152	1.3%
2018	14,975	1.2%	3,194	1.3%
2019	15,158	1.2%	3,236	1.3%
2020	15,362	1.3%	3,282	1.4%
2021	15,543	1.2%	3,324	1.3%
2022	15,737	1.2%	3,368	1.3%

[1]The 2007 figures are weather-normalized actual values.
[2]Summer peak demand forecast includes an estimated 55 MW reduction for curtailable loads. It does not include a 69 MW reduction associated with existing DSM programs.

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 an optimal target reserve margin criterion to be used by the Companies. This study indicates that an optimal target reserve margin in the range of 13 percent to 15 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 Integrated Resource Plan, the Companies used a reserve margin target of 14 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, *2008 Optimal Expansion Plan Analysis* (March 2008) contained in Volume III, Technical Appendix. The in-service years for the units shown assume the Companies' base load forecast.

Table 5.(4)
Recommended 2008 Integrated Resource Plan

Year	Resource
2008	165 MW Purchase Power Contract (June-Sept only) for 2008-2009 11 MW DSM Initiatives (cumulative totals)*
2009	61 MW DSM Initiatives (cumulative totals)*
2010	**549 MW (75% of 732 MW) Trimble County Unit 2 Supercritical Coal**** 125 MW DSM Initiatives (cumulative totals)*
2011	191 MW DSM Initiatives (cumulative totals)*
2012	253 MW DSM Initiatives (cumulative totals)*
2013	314 MW DSM Initiatives (cumulative totals)*
2014	371 MW DSM Initiatives (cumulative totals)*
2015	**475 MW Combined Cycle Combustion Turbine** 425 MW DSM Initiatives (cumulative totals)*
2016	441 MW DSM Initiatives (cumulative totals)*
2017	
2018	
2019	**475 MW Combined Cycle Combustion Turbine**
2020	
2021	
2022	**155 MW Simple Cycle Combustion Turbine**

Note: Unit Ratings are Proposed Summer Net Ratings

* Case No. 2007-00319 approved programs and planned programs in 2008 IRP

** Case No. 2004-00507 – CPCN granted November 1, 2005

The technological status, construction aspects, 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, High Sulfur
Combined Cycle 3x1 GE 7FB Combustion Turbine
Combined Cycle 2x1 GE 7FA Combustion Turbine
Run of River-Ohio Falls Expansion (Units 9 and 10)
Wind Energy Conversion
Simple Cycle GE 7FA Combustion Turbine

Additional detail on the supply-side screening process is contained in the report titled *Analysis of Supply-Side Technology Alternatives* (April 2008) 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 additional programs that will reduce the peak demand for the Companies from 126 MW in 2007 to 551 MW by 2015. When coupling that factor with the significant increases to capital costs for coal options, the base-line IRP recommends that the next generating unit to be added after the already under construction Trimble County Unit 2 in 2010, will be combined cycle combustion turbines in 2015 and 2019, followed by a simple cycle combustion turbine unit in 2022.

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. 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 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 Oct. 25, 2005. The license indicates that the Companies would complete the upgrades to 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 8 is scheduled to begin in 2008.

The Companies continually evaluate resources available to meet load obligations, including the options at the Ohio Falls Station. The remaining five units will undergo investment review prior to rehabilitation taking place. Total rehabilitation of all eight units will result in increasing the expected capacity output of the Ohio Falls Station to 64 MW from the 48 MW capacity output prior to performing rehabilitation. Moreover, the rehabilitation should provide potentially an increase of 187 GWh to annual energy production.

Demand Side Programs

The plan described in Table 5.(4) includes the implementation of approved programs in Case No. 2007-00319 and 12 new programs, labeled collectively as DSM Initiatives. Additional detail on the DSM alternatives in the plan is contained in the report titled *Screening of Demand-Side Management (DSM) Options* (March 2008) contained in Volume III, Technical Appendix.

Non-Utility Sources of Generation

New Long Term Power Purchases

The plan described in Table 5.(4) includes some long-term power purchases from generation not owned by the Companies. 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 May 11, 2007, the Companies sent out a RFP for peaking power for the next few years. Three parties responded with offers to this RFP. The power purchases in Table 5.(4) associated with a peaking power contract with Dynegy from the Bluegrass facility in Oldham County, Ky., in the summer of 2008 and 2009 are a result of this RFP process.

Also, the Companies issued a RFP on July 9, 2007, to explore alternatives using renewable resources for power purchases. The results of the RFP are being explored for future value to the Customers and the Companies. This RFP process is further described in Section 6 under *Renewable Energy*.

Short-Term Power Purchases

The extreme volatility of power prices in the 1990's has not been observed in the current decade due to the increase in supply, i.e. new peaking capacity installed in the region in the past few years. Next-day peak power prices during years 2005 through 2007 have ranged from as low as $7.97/MWH to as high as $144.97/MWH. 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. Due to the uncertainty of environmental regulations for the future, there is the concern that the current lack of commitments to build new generation capacity in the USA in the near future could lead to further price volatility or even challenge the availability of power from the energy commodity market in the future. Also, the lack of electric transmission capability to deliver power from surrounding states will also impact price volatility and the availability of power. The forward market prices for power will reflect this 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.

New Power Plants

The plan described in Table 5.(4) calls for Trimble County Unit 2, a supercritical pulverized coal unit; two new Greenfield combined cycle combustion turbines; and, one Greenfield simple cycle combustion turbine. New power plants are major components of the 15-year least-cost plan.

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 have purchase power arrangements with Owensboro Municipal Utilities (OMU) and Ohio Valley Electric Corporation (OVEC) to provide additional sources of capacity. Under the OMU agreement, the Companies purchase (on an economic basis) the output not needed by OMU's system from two coal-fired, baseload units (combined capacity of approximately 400 MW). In 2008, the Companies expect to receive 168 MW (summer rating) of capacity from OMU. In 2009 and 2010, the expected capacity available to KU is projected to decrease due to increases in OMU's customer load.

On May 11, 2004, the City of Owensboro, Ky., and OMU filed suit against Kentucky Utilities Company in Daviess County, Ky., District Court concerning a long-term power supply contract (OMU Agreement) between KU and OMU. The dispute involves interpretational differences regarding certain issues under the OMU Agreement, including various payments or charges between KU and OMU; rights to excess power from the Smith units above that required to serve the OMU load; the ability to terminate the OMU Agreement; and allocation between KU and OMU of the NO_x emissions allowances issued by the EPA. KU removed the case to federal court in the Western District of Kentucky and filed an answer in that court denying the OMU claims and presenting certain counterclaims. Rulings on the suit remain non-final and subject to appeal. Nonetheless, KU's planning includes the assumption that the OMU contract will expire in May 2010. Further details of this pending lawsuit are described in Section 6.

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 (USEC) 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 (IKEC) Clifty Creek Plant at Madison, Ind. have generating capacities of 1,075 MW and 1,290 MW, respectively.

The 15 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 (PPR). 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 Commission in Case No. 2004-00396. KU retained its 2.5 percent ownership. Therefore, beginning in April 2006, the Companies rely upon 179 MW net for planning purposes during the summer peak and varying capacity during the remaining months due to unit maintenance schedules on the OVEC system.

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, construction of Trimble County Unit 2 will continue as scheduled. The Companies will also undertake all studies and other long lead activities necessary to make a final decision regarding future generating resources. Additionally, DSM measures outlined below will be taken.

Demand-Side Management

The new DSM alternatives included in this plan will be subjected to a much more rigorous review and program design cycle, including pilot programs, which could result in program concepts and program details being changed significantly, or programs not being implemented.

Implementation of the DSM program in the plan will then require the preparation of a multi-year DSM filing that would include any update in program design, would have the selected program by customer class, and would include the recovery of the expected cost to administer the programs and the expected lost revenue for the programs.

As a final step, a RFP will be developed and issued for an administrator/contractor for the program. Marketing representatives for the Companies would be trained on the new customer offerings. The Companies would develop a process to track data related to the programs.

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

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 2008 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 IRP	High	Low
2008	36,835	37,624	36,036
2009	37,404	38,423	36,369
2010	37,921	39,120	36,719
2011	38,531	39,884	37,158
2012	39,080	40,618	37,516
2013	39,535	41,203	37,854
2014	39,927	41,732	38,106
2015	40,298	42,230	38,352
2016	40,695	42,739	38,655
2017	41,153	43,307	39,005
2018	41,725	44,003	39,464
2019	42,270	44,666	39,935
2020	42,914	45,451	40,440
2021	43,449	46,093	40,867
2022	44,036	46,778	41,337

Table 5.(6)-2
Combined Company Base IRP, High, and Low
Peak Demand Forecasts (MW)

Year	Base IRP	High	Low
2008	7,095	7,246	6,942
2009	7,188	7,383	6,990
2010	7,280	7,509	7,050
2011	7,404	7,662	7,141
2012	7,512	7,806	7,213
2013	7,600	7,919	7,279
2014	7,707	8,053	7,358
2015	7,812	8,182	7,439
2016	7,912	8,304	7,521
2017	8,012	8,425	7,601
2018	8,127	8,563	7,693
2019	8,226	8,684	7,779
2020	8,364	8,850	7,890
2021	8,461	8,967	7,967
2022	8,591	9,117	8,075

Short Term Power Purchases

The extreme volatility of power prices in the 1990's has not been observed in the current decade due to the increase in supply, i.e. new peaking capacity installed in the region in the past few years. Since exiting MISO on September 1, 2006 through December 31, 2007, MISO's hourly LMP power prices at the LG&E/MISO interface have ranged from as low as $7.97/MWh to as high as $144.97/MWh. 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 costs resources. Due to the uncertainty of environmental regulations for the future, there is the concern that the current lack of commitments to build new generation capacity in the U.S. in the near future could lead to further price volatility or even challenge the availability of power from the energy commodity market in the future. Also, the lack of electric transmission capability to deliver power from surrounding states will also impact price volatility and the availability of power. The forward market prices for power will reflect this 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

The level of peak reduction ultimately reached in any of the DSM programs in this plan may not equal the target values listed in Table 5.(4). Several things could change that may alter the resulting peak reduction of these programs. The peak reduction for each participant could vary compared to the assumptions. The number of customers willing to participate could vary. If the willingness of customers to participate changes significantly, it may be possible to modify the marketing or redesign the program to maintain the expected level of participation.

The new DSM alternatives included in this plan might not be implemented as they have been described in this report, because any DSM program will be subjected to a much more rigorous review and program design cycle, including pilot programs, which could result in program concepts and program details being changed significantly, or programs not being implemented.

Aging Units

Having operated past their useful lives, several units were retired since the 2005 IRP. Waterside Units 7 and 8 were retired at midnight on Aug. 21, 2006, in conjunction with the sale of that property to the Louisville Arena Authority. As evaluations indicated, Tyrone Units 1 and 2 were retired Feb. 26, 2007. Further details of these unit retirements are described in Section 6 of this IRP.

The generating units in the Companies fleet continue to age. The three oldest steam generating units in the system are Green River Unit 3, 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. 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

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2008)
Steam	Tyrone	3	71	1953	55
Steam	Green River	3	68	1954	54
Steam	Brown	1	101	1957	51
CT	Cane Run	11	14	1968	40
CT	Paddy's Run	11	12	1968	40
CT	Paddy's Run	12	23	1968	40
CT	Zorn	1	14	1969	39
CT	Haefling	1,2,3	36	1970	38

High-level condition assessments (HLCAs) will also be performed on selected generating units in the Companies fleet. The purpose of an HLCA is to provide inputs for long-range power generation planning in terms of projecting major capital and maintenance expenses, predicting significant changes in power output or efficiency, and updating the expected operating life of existing units. HLCAs will identify and evaluate high-level, significant, technical issues that currently exist, or might potentially emerge during the foreseeable life of a generating unit. High level technical issues are defined as issues that affect the capability of critical unit structures, systems or components to perform as required and that could result in a capital investment greater than one million dollars or extended periods (one month or greater) of unexpected lost generating capacity.

The economics surrounding the continued operation of these units are periodically reviewed to ensure the efficiency of the overall system. The relatively high production costs of these 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. The base case integrated plan assumes no retirements in the 15 year window. Any decision to retire generation would change the future capacity needs.

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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 2005 Joint IRP of LG&E and KU. Several significant changes have taken place since that filing, as reviewed in this section. Some changes were initiated in response to the Kentucky Public Service Commission (KPSC) *Staff Report on the 2005 Joint Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company* dated February 2006. The major changes in the 2008 IRP from the 2005 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 2005 plan recommended a supercritical coal unit (Trimble County Unit 2) in 2010, six Greenfield combustion turbines (one in 2013, two in 2015, one in 2016, one in 2017, and one in 2018), one Greenfield supercritical coal unit in 2019, one hydro purchase power agreement in 2014, and a cumulative total of 28.8 MW of new DSM initiatives.

Since the 2005 IRP, the Companies have continued to grow the existing DSM at slightly higher capacities than anticipated in that IRP (achieving 126 MW compared to an expected 122 MW). 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. Construction continues on Trimble County Unit 2 with the expected in-service date in 2010. In the first quarter of 2006, plans for a hydro purchase power agreement anticipated for 2014 were determined to be uneconomic and were terminated. Since the 2005 IRP, the Companies' continuous resource planning process has monitored the latest trends in construction costs and commodity prices, and in most recent evaluations a gas unit has been identified in the least-cost expansion plan.

EEI

KU had a Power Supply Agreement (PSA) with Electric Energy Inc. (EEI) which expired on December 31, 2005. Under the terms of the PSA, KU had a contractual right to 20 percent of the available capacity from EEI's generating station at cost-of service pricing, which accounted for approximately 200 MW. Prior to the expiration of this PSA, KU attempted to renegotiate the extension of this agreement based on the previous cost-of-service terms. Subsequent to December 31, 2005, EEI has sold power under general market-based pricing and terms.

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") continues to be in effect. The Contract expires in January 2020 absent an earlier termination, but OMU has claimed earlier termination rights as discussed below. The pending litigation in U.S. District Court in Owensboro is in the closing stages of discovery and is scheduled for trial in

October 2008. In that litigation, OMU has alleged, among other things, that KU has overcharged OMU for back-up power and that OMU is entitled to certain portions of excess power beyond that needed for the City's native load. The Court has not ruled on those allegations as of this time. However, the Court has ruled upon the unilateral termination rights of the parties. In its ruling, the Court found that the City may terminate the Contract upon four years prior notice to KU.

OMU issued a notice to KU dated May 16, 2006, in which OMU purported to exercise its voluntary right to terminate the contract effective May 2010. The Companies provided response via e-mail to the KPSC on June 23, 2006 showing the Notice from OMU[1]. KU responded to this termination with a letter.[2] On June 11, 2007, KU filed a Motion to Reconsider the Court's July 22, 2005, Partial Summary Judgment Order relating to the termination issue. On November 29, 2007, the Court denied that motion, reaffirming its prior ruling in favor of OMU on the voluntary right to terminate. However, those rulings remain non-final and subject to appeal. Nonetheless, as a result of those rulings, KU's planning includes the assumption that the OMU contract will expire in May 2010.

KU has also filed a counterclaim against OMU, the largest component of which focuses on OMU's operations and maintenance of the Elmer Smith units. It is KU's position that OMU has failed to operate and maintain the units in a good and workmanlike manner, as required by the contract, and that as a result OMU has made less power available to KU in recent years.

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[1] Reference KU's Response to the Request for Information, Item No. 3 in the Commission's Order dated July 6, 2006 in Case No. 2006-00264 for description of the OMU contract.

[2] Ibid.

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

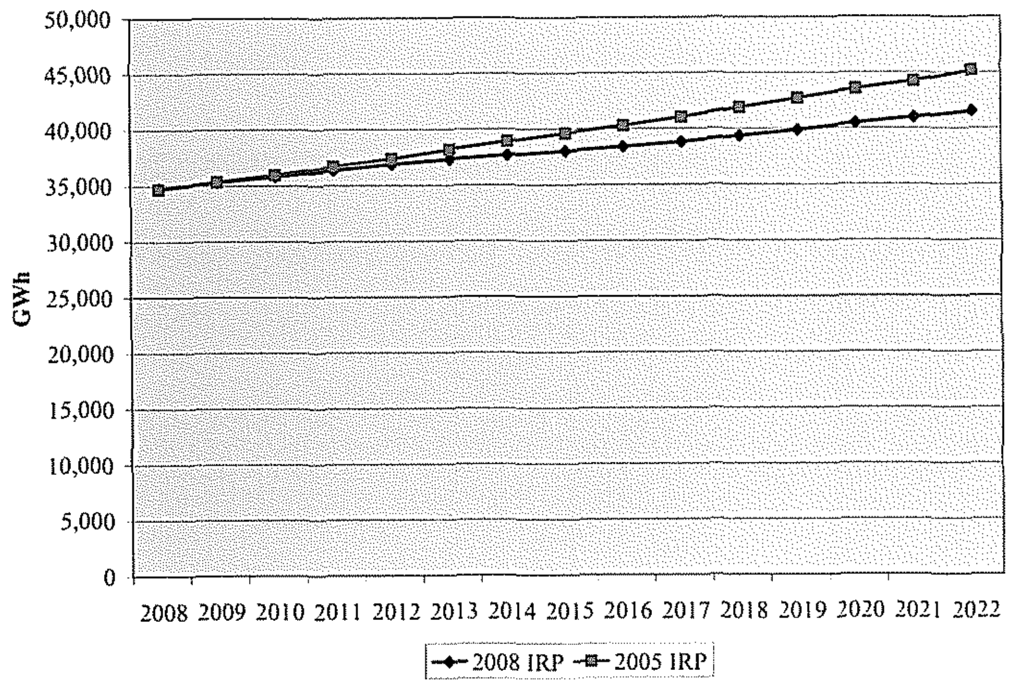
Combined Company

Compared to the 2005 IRP, the current Combined Companies' sales forecast for the 2008-2012 period has been reduced by an average of 202 GWh per year (or 0.5 percent). The anticipated growth in sales during this period is also lower (1.5 percent versus 1.9 percent). Through 2022, the average annual reduction in sales is greater (1,630 GWh). This difference is driven primarily by the disparity in growth rates throughout the forecast period (1.3 percent versus 1.9 percent). The change in sales for each year is shown in Table 6.(1)-1 and in Graph 6.(1)-1. In the 2008 IRP forecast, 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 as well as efficiency gains resulting from the Energy Independence and Security Act of 2007 (ESA 2007) that was signed into law by President Bush in December 2007.

Table 6.(1)-1
Comparison of Combined Companies' 2005 and 2008 IRP Calendar Sales Forecasts

Year	2008 IRP (GWh)	2005 IRP (GWh)	Change (GWh)	% Change
2008	34,775	34,716	59	0.2%
2009	35,311	35,343	-32	-0.1%
2010	35,798	35,966	-168	-0.5%
2011	36,373	36,728	-355	-1.0%
2012	36,889	37,401	-512	-1.4%
2013	37,315	38,200	-885	-2.3%
2014	37,677	38,948	-1,271	-3.3%
2015	38,015	39,653	-1,638	-4.1%
2016	38,381	40,300	-1,919	-4.8%
2017	38,810	41,059	-2,249	-5.5%
2018	39,348	41,907	-2,559	-6.1%
2019	39,862	42,739	-2,877	-6.7%
2020	40,470	43,564	-3,094	-7.1%
2021	40,975	44,247	-3,272	-7.4%
2022	41,529	45,207	-3,678	-8.1%
2008-2012 AVG	1.5%	1.9%	-202	-0.5%
2008-2022 AVG	1.3%	1.9%	-1,630	-3.9%

Graph 6.(1)-1
Combined Company Calendar Sales - 2008 vs. 2005 IRP Forecasts (GWh)

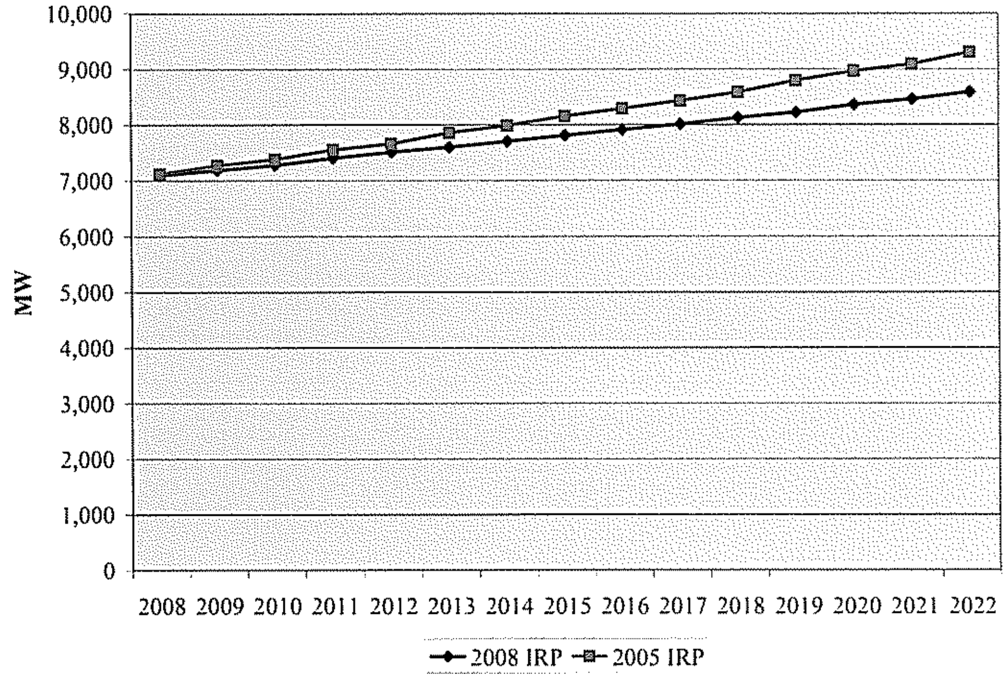


Compared to the 2005 IRP, the current Combined Companies' peak demand forecast for the 2008-2012 period has been reduced by an average of 104 MW (1.4 percent) per year. The anticipated growth in peak demand during this period is also lower (1.4 percent versus 1.8 percent). Through 2022, the average annual reduction in peak demand is greater (345 MW). This difference is driven primarily by the disparity in growth rates throughout the forecast period (1.4 percent versus 1.9 percent). 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. However, peak demand is not impacted as significantly by the ESA 2007, since a large portion of the overall efficiency gains are lighting related (and the consumption of electricity for lighting – particularly residential lighting – occurs primarily in off-peak periods). This explains why peak demand in the 2008 IRP grows at a slightly higher rate than energy sales (1.4 percent versus 1.3 percent).

Table 6.(1)-2
Comparison of Combined Companies' 2005 and 2008 IRP Peak Demand Forecasts

Year	2008 IRP (MW)	2005 IRP (MW)	Change (MW)	% Change
2008	7,095	7,125	-30	-0.4%
2009	7,188	7,272	-84	-1.2%
2010	7,280	7,383	-103	-1.4%
2011	7,404	7,556	-152	-2.0%
2012	7,512	7,662	-150	-2.0%
2013	7,600	7,859	-259	-3.3%
2014	7,707	7,993	-286	-3.6%
2015	7,812	8,159	-347	-4.3%
2016	7,912	8,292	-380	-4.6%
2017	8,012	8,430	-418	-5.0%
2018	8,127	8,587	-460	-5.4%
2019	8,226	8,794	-568	-6.5%
2020	8,364	8,965	-601	-6.7%
2021	8,461	9,087	-626	-6.9%
2022	8,591	9,303	-712	-7.6%
2008-2012 AVG	1.4%	1.8%	-104	-1.4%
2008-2022 AVG	1.4%	1.9%	-345	-4.0%

Graph 6.(1)-2
Combined Companies' Peak Demand – 2008 vs. 2005 IRP Forecasts (MW)



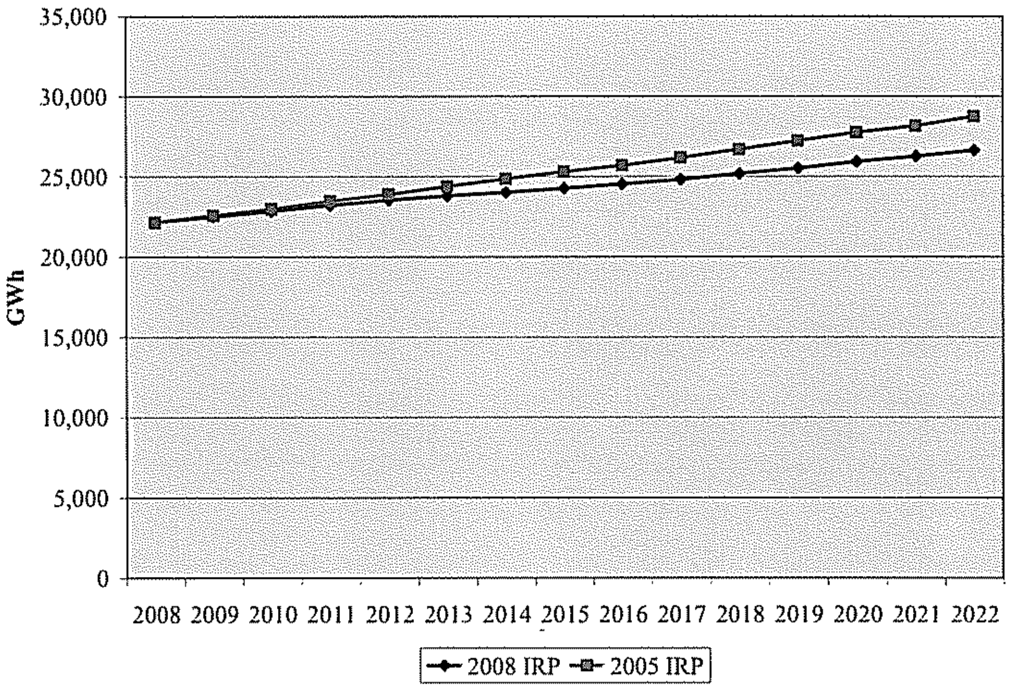
Kentucky Utilities Company

Compared to the 2005 IRP, the current KU sales forecast for the 2008-2012 period has been reduced by an average of 155 GWh per year (or 0.7 percent). The anticipated growth in sales during this period is also lower (1.5 percent versus 1.9 percent). Through 2022, the average annual reduction in sales is greater (989 GWh or 3.7 percent). This difference is driven primarily by the disparity in growth rates throughout the forecast period (1.3 percent versus 1.9 percent). The change in KU sales for each year is shown in Table 6.(1)-3 and in Graph 6.(1)-3. In the 2008 IRP forecast, 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 as well as efficiency gains resulting from the ESA 2007.

Table 6.(1)-3
Comparison of KU's 2005 and 2008 IRP Calendar Sales Forecasts

Year	2008 IRP (GWh)	2005 IRP (GWh)	Change (GWh)	% Change
2008	22,160	22,150	10	0.0%
2009	22,513	22,577	-64	-0.3%
2010	22,843	22,969	-126	-0.6%
2011	23,212	23,458	-246	-1.0%
2012	23,540	23,887	-347	-1.5%
2013	23,796	24,388	-592	-2.4%
2014	24,019	24,869	-850	-3.4%
2015	24,273	25,305	-1,032	-4.1%
2016	24,534	25,695	-1,161	-4.5%
2017	24,821	26,178	-1,357	-5.2%
2018	25,185	26,711	-1,526	-5.7%
2019	25,526	27,233	-1,707	-6.3%
2020	25,941	27,763	-1,822	-6.6%
2021	26,275	28,164	-1,890	-6.7%
2022	26,646	28,767	-2,121	-7.4%
2008-2012 AVG	1.5%	1.9%	-155	-0.7%
2008-2022 AVG	1.3%	1.9%	-989	-3.7%

Graph 6.(1)-3
KU 2005 vs. 2008 IRP Calendar Sales Forecast Comparison (GWh)

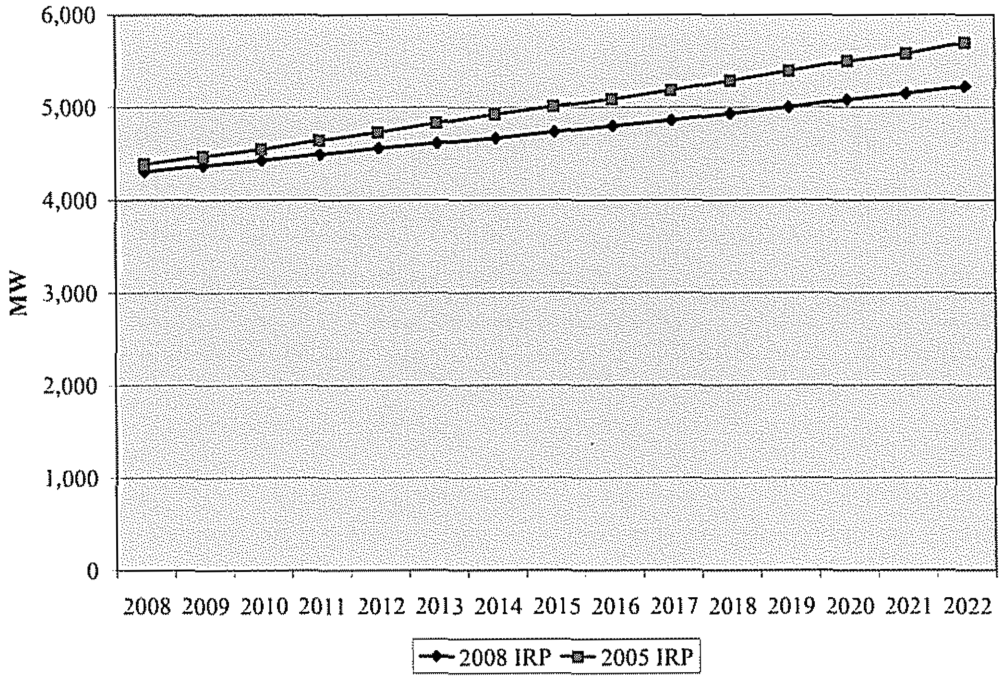


Compared to the 2005 IRP, the current KU peak demand forecast for the 2008-2012 period has been reduced by an average of 125 MW (2.7 percent) per year. The anticipated growth in peak demand during this period is also lower (1.4 percent versus 1.9 percent). Through 2022, the average annual reduction in peak demand is greater (270 MW). This difference is driven primarily by the disparity in growth rates throughout the forecast period (1.4 percent versus 1.9 percent). The change in peak demand for each year is shown in Table 6.(1)-4 and in Graph 6.(1)-4. As with Combined Company peak demand, KU's peak demand is not impacted as significantly by the ESA 2007.

Table 6.(1)-4
Comparison of KU's 2005 and 2008 IRP Peak Demand Forecasts

Year	2008 IRP (MW)	2005 IRP (MW)	Change (MW)	% Change
2008	4,306	4,387	-81	-1.9%
2009	4,371	4,472	-101	-2.3%
2010	4,428	4,549	-121	-2.7%
2011	4,496	4,646	-150	-3.2%
2012	4,560	4,731	-171	-3.6%
2013	4,615	4,830	-215	-4.5%
2014	4,669	4,925	-256	-5.2%
2015	4,736	5,012	-276	-5.5%
2016	4,799	5,089	-290	-5.7%
2017	4,861	5,184	-323	-6.2%
2018	4,933	5,290	-357	-6.8%
2019	5,001	5,393	-392	-7.3%
2020	5,082	5,499	-417	-7.6%
2021	5,149	5,579	-430	-7.7%
2022	5,223	5,697	-474	-8.3%
2008-2012 AVG	1.4%	1.9%	-125	-2.7%
2008-2022 AVG	1.4%	1.9%	-270	-5.2%

Graph 6.(1)-4
KU 2005 vs. 2008 IRP Peak Demand Forecast Comparison (MW)



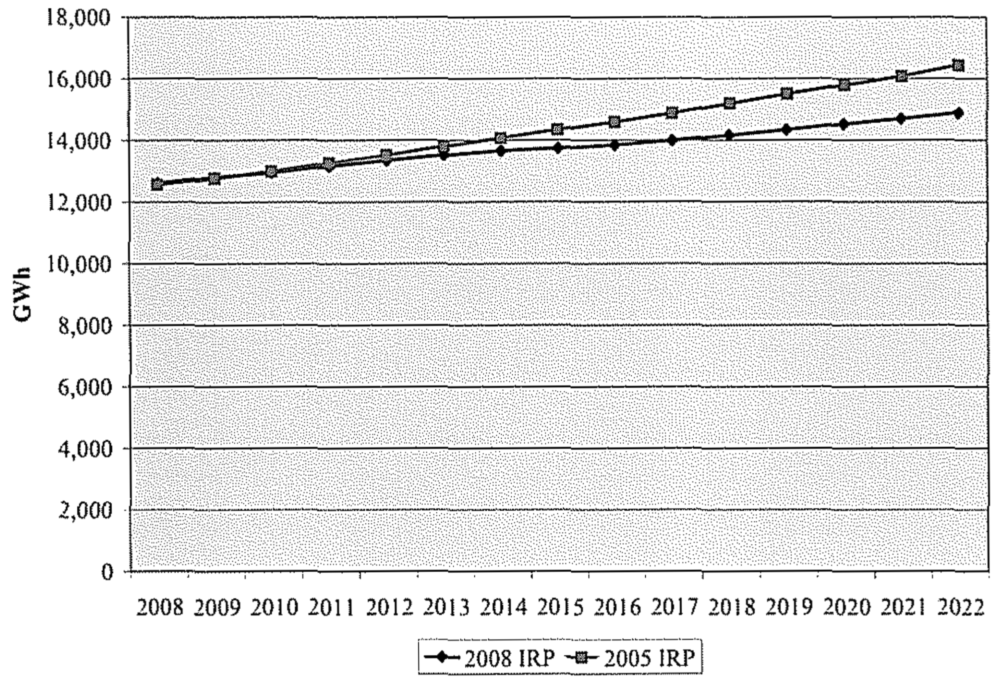
Louisville Gas and Electric Company

Compared to the 2005 IRP, the current LG&E sales forecast for the 2008-2012 period has been reduced by an average of 47 GWh per year (or 0.3 percent). The anticipated growth in sales during this period is also lower (1.4 percent versus 1.8 percent). Through 2022, the average annual reduction in sales is greater (641 GWh or 4.2 percent). This difference is driven primarily by the disparity in growth rates throughout the forecast period (1.2 percent versus 1.9 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 2008 IRP forecast, 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 as well as efficiency gains resulting from the ESA 2007. Compared to the KU service territory, the lower growth in sales in the LG&E service territory (1.2 percent over the 2008-2022 period versus 1.3 percent) is driven by lower growth in sales to LG&E's large commercial/industrial customers.

Table 6.(1)-5
Comparison of LG&E's 2005 and 2008 IRP Calendar Sales Forecasts

Year	2008 IRP (GWh)	2005 IRP (GWh)	Change (GWh)	% Change
2008	12,615	12,566	49	0.4%
2009	12,797	12,766	31	0.2%
2010	12,956	12,997	-41	-0.3%
2011	13,162	13,270	-108	-0.8%
2012	13,350	13,514	-164	-1.2%
2013	13,519	13,812	-293	-2.1%
2014	13,657	14,079	-422	-3.0%
2015	13,741	14,349	-608	-4.2%
2016	13,847	14,605	-758	-5.2%
2017	13,989	14,881	-892	-6.0%
2018	14,163	15,197	-1,034	-6.8%
2019	14,336	15,506	-1,170	-7.5%
2020	14,528	15,801	-1,273	-8.1%
2021	14,700	16,082	-1,382	-8.6%
2022	14,883	16,440	-1,557	-9.5%
2008-2012 AVG	1.4%	1.8%	-47	-0.3%
2008-2022 AVG	1.2%	1.9%	-641	-4.2%

Graph 6.(1)-5
LG&E 2005 vs. 2008 IRP Calendar Sales Forecast Comparison (GWh)

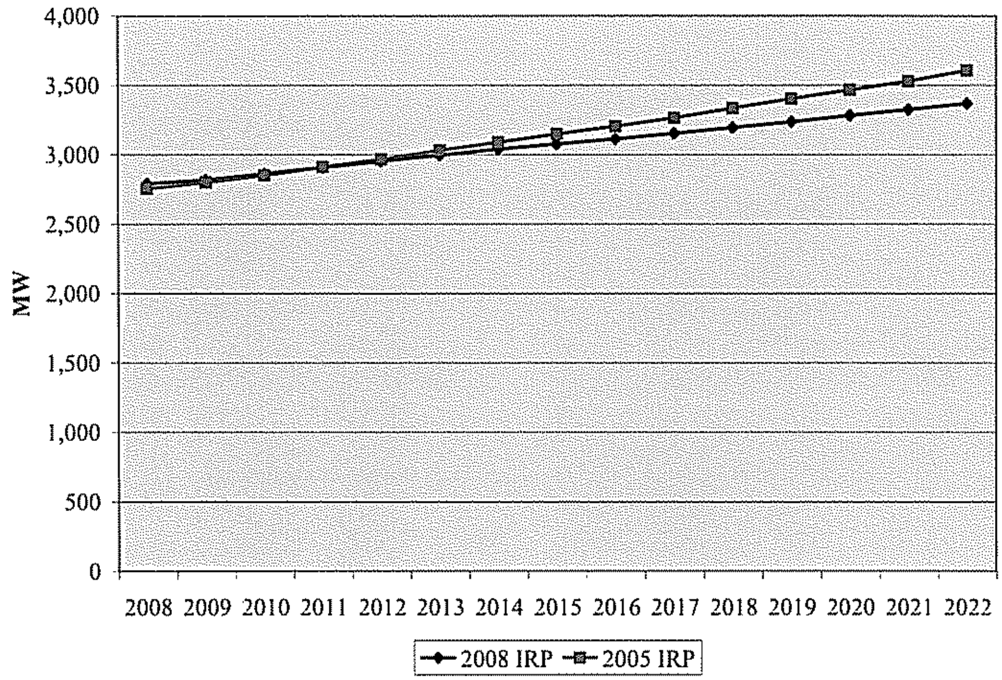


Compared to the 2005 IRP, the current LG&E peak demand forecast for the 2008-2012 period has been increased by an average of 10 MW (0.4 percent) per year. However, the anticipated growth in peak demand during this period is lower (1.4 percent versus 1.8 percent). Through 2022, the current LG&E peak demand forecast has been reduced by an average of 83 MW (2.4 percent) per year. This reduction is driven primarily by the disparity in growth rates throughout the forecast period (1.4 percent versus 1.9 percent). The change in peak demand for each year is shown in Table 6.(1)-6 and in Graph 6.(1)-6. As with Combined Company peak demand, LG&E's peak demand is not impacted as significantly by the ESA 2007.

Table 6.(1)-6
Comparison of LG&E's 2005 and 2008 IRP Peak Demand Forecasts

Year	2008 IRP	2005 IRP	Change	% Change
2008	2,789	2,756	33	1.2%
2009	2,817	2,800	17	0.6%
2010	2,862	2,850	12	0.4%
2011	2,908	2,910	-2	-0.1%
2012	2,952	2,964	-12	-0.4%
2013	2,995	3,029	-34	-1.1%
2014	3,038	3,088	-50	-1.6%
2015	3,075	3,147	-72	-2.3%
2016	3,113	3,203	-90	-2.8%
2017	3,152	3,264	-112	-3.4%
2018	3,194	3,333	-139	-4.2%
2019	3,236	3,401	-165	-4.9%
2020	3,282	3,466	-184	-5.3%
2021	3,324	3,528	-204	-5.8%
2022	3,368	3,606	-238	-6.6%
2008-2012 AVG	1.4%	1.8%	10	0.4%
2008-2022 AVG	1.4%	1.9%	-83	-2.4%

Graph 6.(1)-6
LG&E 2008 vs. 2005 IRP Peak Demand Forecast Comparison (MW)



Reason for Forecast Changes

The energy and demand forecasts in the 2008 IRP reflect the following changes from the previous filing:

- incorporation of more recent sales trends in the forecasting models;
- incorporation of the impacts of the Energy Independence and Security Act of 2007;
- changes in the curtailable/interruptible loads;
- incorporation of more recent weather data in the calculation of 'normal' weather;
- updates to the economic and demographic assumptions; and
- updates to the methodology used to prepare the forecast.

Recent Sales Trends

Combined Company

On a Combined Company basis, weather-normalized calendar sales were close to forecasted levels between 2005 and 2007 (see Table 6.(1)-7). As a result, the differences between the 2005 and 2008 IRP forecasts through 2012 are relatively minor.

Table 6.(1)-7
Combined Company Calendar Sales (GWh)
Variance to 2005 IRP Forecast

Year	2005 IRP	W/N Actuals	Difference	% Difference
2005	32,522	32,709	187	0.6%
2006	33,160	33,063	-97	-0.3%
2007	33,922	33,706	-216	-0.6%

Kentucky Utilities Company

KU's weather-normalized calendar sales were close to forecasted levels between 2005 and 2007 (see Table 6.(1)-8). As a result, the differences between the 2005 and 2008 IRP forecasts through 2012 are relatively minor.

Table 6.(1)-8
Kentucky Utilities Company Calendar Sales (GWh)
Variance to 2005 IRP Forecast

Year	2005 IRP	W/N Actuals	Difference	% Difference
2005	20,532	20,769	237	1.2%
2006	20,967	20,927	-40	-0.2%
2007	21,585	21,437	-148	-0.7%

Louisville Gas and Electric Company

LG&E's weather-normalized calendar sales were also close to forecasted levels between 2005 and 2007 (see Table 6.(1)-9). As a result, the differences between the 2005 and 2008 IRP forecasts through 2012 are relatively minor.

Table 6.(1)-9
Louisville Gas and Electric Company Calendar Sales (GWh)
Variance to 2005 IRP Forecast

Year	2005 IRP	W/N Actuals	Difference	% Difference
2005	11,991	11,940	-51	-0.4%
2006	12,193	12,136	-57	-0.5%
2007	12,337	12,269	-68	-0.6%

Energy Independence and Security Act of 2007

The Energy Independence and Security Act of 2007 (ESA 2007) was signed into law by President Bush in December 2007. The provisions in ESA 2007 are primarily designed to increase energy efficiency and the availability of renewable energy. LG&E and KU electricity sales will be impacted primarily 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. The 2008 IRP incorporates the impact of the new lighting and appliance efficiency standards on electricity sales. New building and commercial equipment standards have not been developed, so the potential impact of these standards has not been incorporated.

Lighting Efficiency

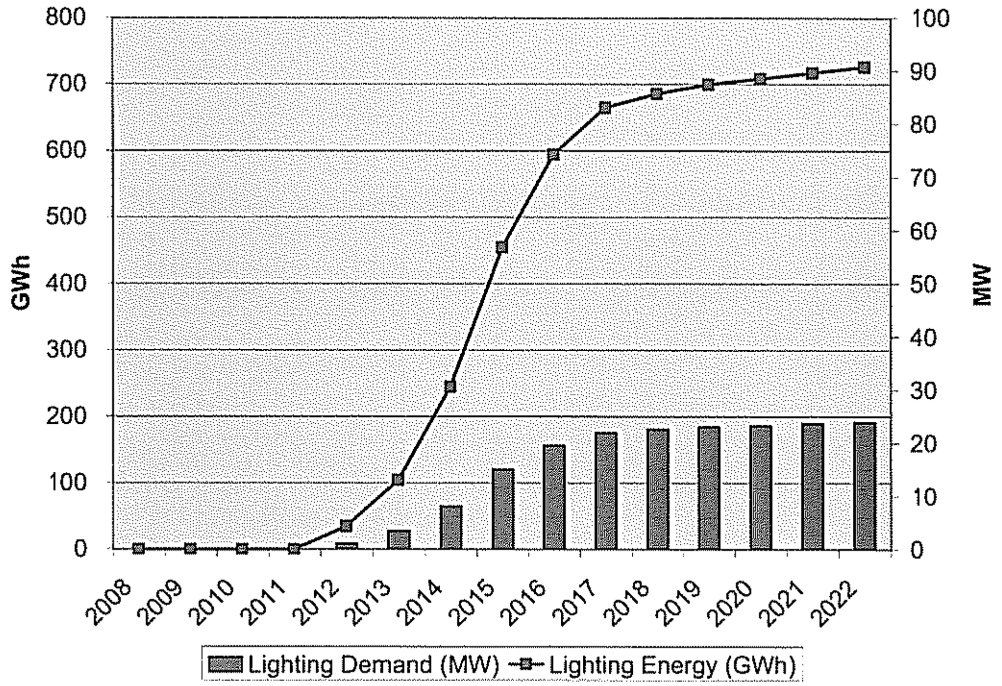
The provisions in ESA 2007 related to lighting efficiency classify light bulbs by the amount of light emitted and reduce the maximum wattage (for a given range of light output) to levels existing incandescent bulbs cannot meet. This means that existing incandescent bulbs will eventually be phased out as a result of these reductions, which are scheduled to take place between 2012 and 2014.

The guidelines set forth in the energy bill mandate an energy savings of approximately 30 percent when replacing incandescent bulbs. However, an alternative to incandescent bulbs that results in an energy savings of only 30 percent currently does not exist. Today, according to Energy Star, replacing an incandescent bulb with a compact fluorescent light (CFL) with equivalent light output will result in approximately a 75 percent reduction in energy use. Interestingly, the new energy bill appears to leave a door open for the development of a more efficient incandescent bulb.

According to the PIRA Energy Group (PIRA), lighting accounts for 15-20 percent of all electric energy consumption, and incandescent lamps are responsible for approximately 42 percent of the lighting energy requirement. In total, LG&E and KU electric customers are expected to consume approximately 37 TWh in 2012. In the 2008 IRP sales forecast, the estimated reduction in electricity sales due to improved lighting efficiencies is 700 GWh (around 2 percent). In addition, because not everyone will replace their incandescent bulbs immediately, it is likely that the reduction will be phased in over time.

Graph 6.(1)-7 summarizes the energy and peak demand reductions resulting from the increased lighting efficiencies. A total energy reduction of 700 GWh is achieved gradually over a six- or seven-year period beginning in 2012. Because lighting is utilized primarily in the morning and evening hours and the summer peak demand typically occurs in the afternoon, the impact to peak demand is relatively small (approximately 22 MW in 2019 or 0.3 percent overall).

Graph 6.(1)-7
ESA 2007 – Lighting Efficiency Reductions



Appliance Efficiency

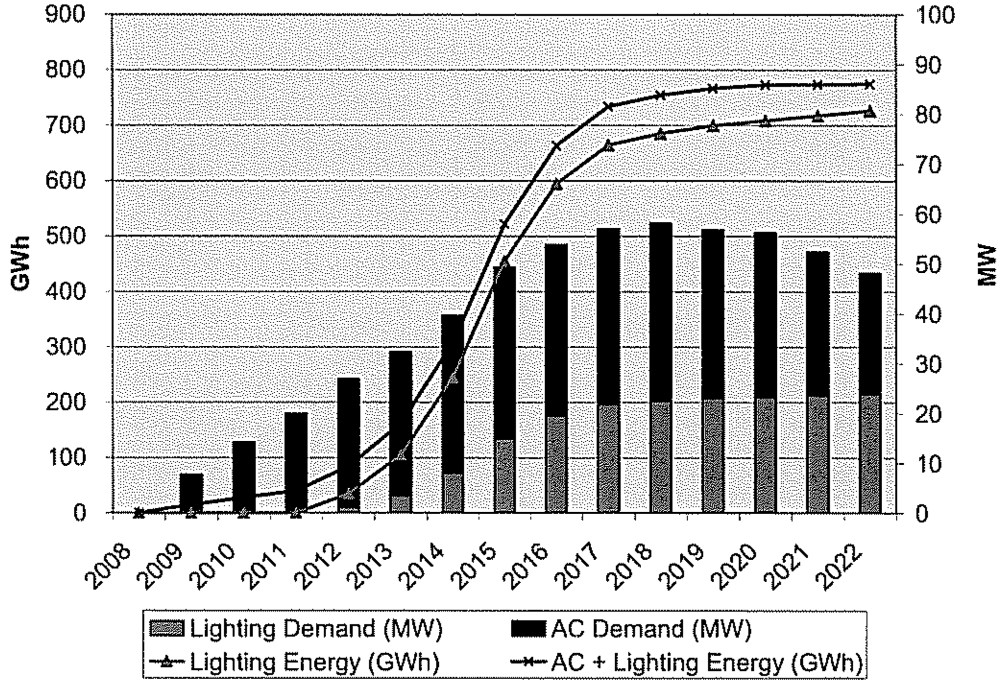
The provisions in ESA 2007 related to appliance efficiency set specific standards for 10 appliance and equipment products including residential boilers, clothes washers, and dishwashers. The implementation dates for the new standards range from 2008 through 2014.

KU and LG&E already assume that appliance efficiencies will increase over time. As a result, the impact from the new appliance efficiency mandates is small. In fact, the only efficiency mandate that would precipitate a change in the forecast assumptions pertains to central air conditioning (AC) equipment. Beginning in mid-2008, ESA 2007 increases the minimum seasonal energy efficiency ratio (SEER) from 12 to 13.

Graph 6.(1)-8 shows the total energy and peak demand reductions for LG&E and KU due to the new lighting and appliance efficiency standards. The incremental reduction in energy associated with the improved AC efficiencies is small compared to the lighting-related energy reductions. However, because air conditioners are utilized more during the day, the impact to peak demand is relatively larger.

As a result of ESA 2007, electricity sales are reduced in 2018 by approximately 750 GWh (2 percent) and peak demand is reduced by 58 MW (0.7 percent).

Graph 6.(1)-8
ESA 2007 – Lighting & Air Conditioner (AC) Efficiency Reductions



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 (Curtailable Service Rider, or CSR). 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. However, the changes in the amount of curtailable demand from the 2005 IRP to the 2008 IRP are minor (see Table 6.(1)-10).

Table 6.(1)-10

Total Curtailable/Interruptible Load Provision (MW)

Forecast	KU	LG&E	Combined
2005 IRP	51	49	100
2008 IRP	50	55	105
Change	(1)	6	5

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 2008 IRP forecast is based on the weather in the 20-year period ending in 2006; the weather in the 2005 IRP was based on the weather in the 20-year period ending in 2003. 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 2008 IRP forecast, normal weather for the KU service territory incorporates an average of 4,525 HDDs and 1,219 CDDs each year over the forecast period (on a 65-degree base). The normal Lexington weather assumption was 4,572 HDDs and 1,240 CDDs in the 2005 IRP. Interestingly, the summers and winters in the more recent 20-year period (1987-

2006) have both been milder on average in the KU service territory than the 20-year period utilized for the 2005 IRP (1984-2003).

Normal weather for the LG&E service territory is assumed to be 4,062 HDDs and 1,578 CDDs (also on a 65-degree base). Normal Louisville weather assumption in the 2005 IRP was 4,147 HDDs and 1,553 CDDs. In the LG&E service territory, the summers in the more recent 20-year period have been warmer than the 20-year period utilized for the 2005 IRP; the winters have been milder.

Service Territory Economic and Demographic Forecasts

In the 2005 IRP forecast, service-territory-level economic and demographic forecasts were developed using an employment-driven model (STEM) in which forecasts of sector level value-added, employment, income and population are generated for five regions that correspond to KU's and LG&E's service territories. These forecasts were developed by the University of Kentucky's Gatton Center for Business and Economic Research (CBER) and incorporated national-level economic and demographic forecast inputs from Global Insight.

In the 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 completely consistent with the national-level forecasts from Global Insight.

Following is a summary of key assumptions made in Global Insight's 2007 Long-Term Macro Forecast, used by the Companies as macroeconomic background for the energy sales forecast in the 2008 IRP. A copy of this forecast is attached as part of Technical Appendix 3, 'Supporting Documents,' in Volume II.

- *Trend Scenario*: The scenario assumes no major disruptions to the long-term growth trend. The projection is best described as depicting the mean of all possible paths the economy could follow. Economic output is forecast to grow smoothly.

- *Demographics*: The population projection in the trend scenario is consistent with the Census Bureau's latest 'interim' projections which were released in May 2004. Based on specific assumptions about immigration, fertility and mortality rates, U.S. population was forecast to achieve average annual growth of 0.8 percent through 2030.

- *Employment:* Overall employment was forecast to grow approximately 0.8 percent per year over the forecast period.

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

In addition to national- and state-level data, Global Insight provided county-level economic and demographic forecasts. Service-territory level forecasts were created as an aggregate of the county-level forecasts. These forecasts are addressed further in section 5.(3).

Changes in Methodology

Several changes in forecasting methodology were incorporated in the 2008 IRP forecasts to streamline and further integrate the forecasting process while maintaining or enhancing the consistency of data inputs and the quality of the forecast. The following changes were made:

- Service-territory-level economic and demographic forecasts were developed by aggregating county-level forecasts from Global Insight (see discussion above regarding Service Territory Economic and Demographic Forecasts).

- Several forecasts in the 2005 IRP were developed by extending a medium-term forecast per the rate of growth in a separate long-term model. This two-model structure was replaced in the 2008 IRP by a one-model structure that continues to capture the monthly fluctuations in sales as well as long-term trends.

- KU's commercial and industrial forecasts are no longer segmented by SIC code. Instead, commercial and industrial sales are forecasted by rate code (or homogenous groups of rate codes). The new methodology is consistent with the methodology used to forecast LG&E's commercial and industrial sales. Please see Section 7 for a more detailed discussion of the forecast models.
- In the 2005 IRP, KU's residential service (RS) and full-electric residential service (FERS) rate classes were forecasted separately. In the 2004 rate case, the differences between the RS and FERS rates were eliminated. Since KU's residential end-use forecasting model gives the Company the ability to capture the differences between RS and FERS customers in one model, sales to all of KU's residential customers were forecasted together in the 2008 IRP.
- In the 2005 IRP, the Electric Power Research Institute's Residential Energy End-Use Planning System (REEPS) model served a supporting role rather than a direct role in the development of appliance saturation forecasts for the residential use-per-customer forecast. The REEPS model was not utilized in the 2008 IRP forecast. Instead, appliance saturation forecasts were taken from the Energy Information Administration (EIA).

DEMAND-SIDE MANAGEMENT

The screening of DSM options was performed on a joint-company basis. The DSM objectives in the 2008 IRP are similar to the DSM objectives in previous filings, but the DSM alternatives considered does not include programs for industrial customers. The quantitative screening process utilizes Quantec's DSM Portfolio Pro software.

For more details on the DSM screening see the report titled *Screening of Demand-Side Management (DSM) Options* in Volume III, Technical Appendix.

Energy Efficiency Filing

On July 19, 2007, the Companies filed a joint application for the review, modification and continuation of energy efficiency programs and DSM cost-recovery mechanisms (Case No. 2007-00319), which was approved by the Commission on March 31, 2008. The energy and demand figures contained in the DSM portions of the IRP indicate these as "approved DSM programs."

The 12 new programs which passed the screening process of the IRP will continue to be investigated and refined. As these programs continue through the design cycle, significant changes could occur, including recommendation for pilot program status, or programs not being implemented.

The Companies see a significant effort ahead in the implementation of the approved programs contained in Case No. 2007-00319 during 2008. During 2009, additional analysis and programming design decisions will result in the preparation of a future DSM filing with the Commission, requesting approval of the new programs contained in this IRP.

RELIABILITY CRITERIA

In the Joint Companies 2005 IRP, the Companies used a combined target reserve margin of 14 percent, in the recommended range of 12 percent to 14 percent. In the current assessment and acquisition study, the Companies continue to use a combined target reserve margin of 14 percent, in the recommended range of 13 percent to 15 percent. A discussion of the reliability criteria is found in the report titled *2008 Analysis of Reserve Margin Planning Criterion* (March 2008) contained in Volume III, Technical Appendix.

WHOLESALE POWER MARKET

Generation Outlook

At national level, particularly with the present uncertainties surrounding the impact of possible greenhouse gas legislation and of various energy efficiency and conservation initiatives, there is no clear consensus on the trend in the growth of electricity demand, nor on the schedule or structure of generation capacity additions which will be required to meet that demand over the next 5 to 10 years. Reputable agencies and industry analysts offer differing projections of the magnitude of new capacity build required to meet demand growth and provide adequate reserve margins. Views differ also on the structure of the (incremental) supply mix, - between coal-fired, gas-fired, nuclear, and renewables and other generation technology options – which represents not only the lowest-cost but also the most robust capacity development strategy in a volatile energy market. CERA forecasts a total of 80 GW of U.S. generation capacity additions over the next five years (2008 – 2012), of which around one half is gas-fired and 27 percent coal-fired. For the same period the EIA, developing the theme of intensifying energy efficiency measures in its 2008 Annual Energy Outlook, anticipates only 41

GW of new generation capacity, of which around 40 percent is gas-fired and 30 percent coal-fired. Global Energy's reference projection similarly includes a moderate capacity build of 40 GW through 2012, in this case heavily weighted towards gas-fired plant (62 percent of the total, to 26 percent for coal-fired plant).

Regarding the longer-term, the EIA projects a total of 61 GW of additional generation capacity over the period 2008–2017; in the later years, development of coal-fired capacity gathers pace such that by 2017 such units account for 40 percent of total incremental capacity against 30 percent for gas-fired generation. In comparison, Global Energy projects a much stronger longer-term build-out once the present excess reserve margins have cleared, with 144 GW of new capacity added over the next ten years – of which over three-quarters is gas-fired.

In the Midwest market, CERA believes that over the next five years there will be sufficient reserve capacity to meet load growth assuming completion of announced base-load projects (after recognition of expected retirements). Because of the present capacity overhang in the region, CERA projects only 14 GW of new generation additions across the Midwest/Midsouth (RFC-Midwest, TVA and VACAR) through 2012, of which over one half will be coal-fired and one-third gas-fired. With rising environmental concerns some of this coal-fired capacity could be at risk.

For the region as a whole, the overhang of excess generation capacity will largely disappear by 2012, with the reserve margin declining from around 20 percent at present to 16.5 percent. In anticipation of more uncertain market conditions and regulatory requirements, certain load serving entities (LSEs) are investigating opportunities to secure long-term transmission service outside their immediate control area to maintain maximum flexibility in supply.

Transmission Outlook

Also impacting power market liquidity is the absence of high-voltage interregional transmission system enhancements in the Midwest in the past decade. This lack of transmission enhancements has resulted in less and less available transfer capability (ATC) being 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. The availability of ATC has also been impacted by the start-up of Regional Transmission Operator (RTO) Energy Markets in the Midwest and the accompanying "seams" agreements between the market areas and the adjacent non-market areas. These seams agreements attempt to allocate capacity of constrained flowgates based on historic usage, but in some areas have resulted in less transmission capacity available in the wholesale market.

The Midwest Independent System Operator (Midwest ISO or MISO) market, and the PJM (the ISO originally founded for Pennsylvania, (New) Jersey, and Maryland) market as well, have created after-the-fact price information for energy traded between RTOs or non-RTO counterparties. These markets have not provided forward-looking price transparency, and have in fact introduced additional price risks like after-the-fact changes to Locational Marginal Pricing (LMP) settlements and Reserve Sharing Group (RSG) adders. There has been the development of a financial market through the Intercontinental Exchange (ICE) trading system that gives a limited forward look, approximately one year out, of the price for on-peak power.

While MISO's energy markets are now established, long-term generation adequacy within the RTO is still concerning and remains a significant issue. Revisions to the MISO tariff to include a means to maintain resource adequacy in the RTO footprint are expected to be filed in 2008. Initial drafts have LSEs within MISO being responsible for procuring capacity sufficient to meet forecasted load. It is unclear how MISO can enforce such a requirement, particularly in retail choice states like Ohio, Michigan and Illinois. LSE load in these states constantly changes and LSEs competing on costs are driven to incur as little capacity cost as possible.

MISO intends to begin its Day 3 in September of 2008. Day 3 is an ancillary services market focused on operating reserves, generation capacity that is connected to the grid and ready to produce electric energy immediately to ensure reliability. Although the impacts of the ancillary services market on the wholesale power markets are at this time unclear, this operating reserve market could conceivably impact the makeup of regional reserve sharing groups which in turn will impact the amount of generation capacity producing energy being offered in the wholesale markets that exist today.

Changes in the Primary Energy Balance

The power sector has been the leading contributor to the growth in the U.S. natural gas market over the last decade. Gas-fired electric generation capacity almost doubled between 1996 and 2005 and consumption of natural gas by the power industry has risen from 11 billion cubic feet (Bcf) per day on average in 1997 to an estimated 19 Bcf per day in 2007 (EIA data). Although domestic conventional gas production is expected to continue to decline, the Industry has responded by increasing production from unconventional sources – tight gas, shale gas, and coal bed-methane. This is expected to make up most if not all of the decline from conventional sources.

Much of the growth in domestic gas demand will be supplied by imported Liquified Natural Gas (LNG) which is projected by the EIA to increase from 1.6 Bcf per day in 2006 to 4 Bcf per day in 2008 and 7 to 10 Bcf per day in 2012. Unlike domestic gas supply, which is produced at a fairly steady rate and limited to the continental market, LNG imports are subject to global competition for supply (between the U.S., Europe and Asia).

While increasing geographical diversity of supply, higher levels of dependence on LNG imports will create the need for parallel review and development of the transport and storage infrastructures necessary to address issues relating to price volatility or security-of-supply. Concerns regarding electric power and gas interdependency have already been raised in various electric reliability venues, and market regulators must continue to work with industry players to develop appropriate supply, infrastructure and operations strategies to accommodate an evolving pattern of primary resource provisions. For example, as a result of a January 2004 cold snap in New England during which record demand for both electricity and natural gas left some operators with fuel shortages, FERC issued an Order (698) directing operators of gas-fired generation and pipelines to establish communications protocols to improve reliability in each industry. It is anticipated that power generation gas demand could grow to 26 Bcf per day (Cambridge Energy Research Associates estimate) over the next ten years given increased utilization of the existing fleet of gas-fired plants along with the addition of new gas-fired generating capacity. As new gas-fired generating capacity contributed to the expansion of gas pipeline systems over the last several years, additional investment in gas supply infrastructure (e.g. gas pipeline and LNG receiving terminals) is anticipated throughout the next ten years. LNG regasification capacity currently under construction or committed will increase import capacity from 4.1 Bcf per day in 2007 to 14 Bcf per day by 2012 (CERA analysis).

Potential Impact of Climate Change Legislation/Regulation

Legislation and regulation addressing climate change continues to be proposed on the international, federal, state and local levels. There are no specific mandates presently impacting Kentucky, nor is there a clear consensus of what might be implemented. Federal proposals vary dramatically in structure and format; however most of them share several common traits, notably, targeted emission reductions by 2020 and much more aggressive reductions by 2050. A variety of "cap and trade" policies are also common in many proposals, capping greenhouse gas emissions across the economy and allowing sources to trade emission allowances with each other to meet their emission targets. The proposals vary dramatically in their particulars, including whether they incorporate "safety valves" (i.e., maximum CO_2 prices) and how emissions credits might be allocated. In addition, as a result of a 2007 ruling by the United States Supreme Court holding that EPA has authority to regulate certain GHG emissions under the Clean Air Act, EPA has announced that it intends to explore potential GHG regulations for various sources including power plants. This uncertain legislative/regulatory situation impacts nationwide utility commitments to build carbon-intensive generation.

REHABILITATION OF OHIO FALLS

The 2005 IRP identified that LG&E, on the behalf of Ohio Falls Station, had requested a new license from FERC on March 3, 2005. On October 25, 2005, FERC granted a 40-year license to Ohio Falls Station.

Also, the 2005 IRP indicated that without Phase 3 of the rehabilitation of these eighty-year-old units at Ohio Falls Station, they would likely have greatly reduced generation or the generation could be lost completely, in the event of a catastrophic failure. Phase 3 of the rehabilitation for all eight units increases the expected capacity of the facility from the current planned value at the time of summer peak of 48 MW to 64 MW and increases the energy from the five-year average production of 250 GWh to 438 GWh.

The rehabilitation on the first unit, Ohio Falls Station Unit 7, was completed on October 13, 2006. Ohio Falls Station Unit 6 completed rehabilitation on January 31, 2008. Approval of the investment proposal to complete the rehabilitation of Ohio Falls Station Unit 8 occurred in the fourth quarter of 2007 for work to begin in 2008 for approximately $13 million. Even though the FERC license indicates that the Companies shall complete the upgrades to the project within nine years from the effective date of the new license, each of the remaining five units will be reviewed again in the future for investment approval.

UNIT RETIREMENTS

Waterside 7 and 8

Waterside Units 7 and 8 were retired at midnight on August 21, 2006 in conjunction with the sale of that property to the Louisville Arena Authority as approved by the KPSC in Case No. 2006-00391. Details of that case, including the life assessment study performed, can be found at http://psc.ky.gov/pscscf/2006%20cases/2006-00391/LGE_ApplicationAddendumPetition_082406.pdf. The retirement of Waterside Units 7 and 8 was booked on September 30, 2006, and Account 101 (Electric Plant in Service) was reduced by the value of the generation units at that time.

Tyrone 1 and 2

Tyrone Units 1 and 2 were retired at midnight on February 26, 2007. Prior to their request from dispatch to operate in 2006, the units had not run since 2001 when they operated 143 and 133 service hours, respectively. A life assessment study was performed pursuant a forced outage on both units which began on July 26, 2006, regarding service water pumps. The study was provided in the March 2, 2007, Supplemental response to Commission Staff's Interrogatories of February 8, 2007 in the two-year FAC review approved by the KPSC in Case No. 2006-00509. Details of that case, including the life assessment performed, can be found at http://psc.ky.gov/pscscf/2006%20cases/2006-00509/KU_Response_030207.pdf. The retirement of Tyrone Units 1 and 2 was booked on March 31, 2007, and Account 101 (Electric Plant in Service) was reduced by the value of the generation units at that time.

EXIT FROM MISO

The Companies had been a charter member of MISO since 1998. Beginning April 1, 2005, MISO implemented day-ahead and real-time energy markets (Day 2) pursuant to the MISO Energy Markets Tariff. This substantial mission change did not prove cost-effective for the Companies or its customers. Therefore, the Companies sought rulings to leave MISO.

On July 6 and 7 of 2006, the KPSC and FERC completed their final round of rulings allowing the Companies to exit MISO and allow the Southwest Power Pool (SPP) to serve as the Independent Transmission Operator (ITO) and Tennessee Valley Authority (TVA) to serve as the reliability coordinator. The exit took place and business with SPP and TVA commenced on September 1, 2006. The Companies experience with TVA as reliability coordinator and SPP as ITO has been good.

NERC RELATED TOPICS

Since the 2005 IRP, the region of the North American Electric Reliability Corporation (NERC) to which the Companies belong has changed twice. In 2005, the Companies belonged to NERC's East Central Area Reliability Council (ECAR) region. Effective January 1, 2006, ECAR and two other regions were grouped together as one region called Reliability First Corporation (RFC). However, resultant from the Companies exit from MISO, the Companies changed regions to align with TVA in the Southeast Reliability Corporation (SERC) effective January 1, 2007.

As a result of this change, the operating reserve requirement for the Companies has changed from ECAR's minimum daily operating reserve requirement of approximately 4 percent. Now that the Companies belong in the SERC region, the requirement is to cover one and a half times the size of the largest unit or to belong to a RSG and follow their requirements. The Companies belong to the Midwest Contingency RSG (MCRSG). In the MCRSG, the Companies contingency obligation is 91 MW. Additionally, the Companies have frequency regulations and load following requirements which they must meet. SERC's requirement is that the Companies must carry enough reserves to meet the control performance standards, and it is up to each company within SERC to determine how to meet that obligation. Currently, the Companies target a minimum of 83 MW for sufficient regulation reserves for frequency response and compliance with the control performance standards and load following totaling 174 MW total as a daily operating reserve minimum.

In July 2006, FERC certified NERC as the Electric Reliability Organization. Resultant from that, NERC required mandatory compliance with the Reliability Standards as approved and established for electric utilities by FERC effective June 18, 2007. Thus far, FERC has approved more than 90 Mandatory Reliability Standards established by NERC. Compliance with these standards includes plans for each region and utility that assures reliability of electricity across the national grid. The Companies are continuing to evaluate and assess their internal processes and practices in order to achieve a high level of consistency with the Reliability Standards.

RENEWABLE ENERGY

Green Energy Program

Continuing to follow through with the prior recommendation for offering green power alternatives as addressed in the KPSC *Staff Report on the 2002 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company* dated December 2002, on February 9, 2007, the Companies submitted an application (Case No. 2007-00067) to the KPSC to establish a Green Energy Program. On May 31, 2007, the KPSC approved the program as filed. This program allows customers to contribute funds to be used for the purchase of Renewable Energy Certificates (RECs) or "Green Tags" by LG&E and KU.

Specifically, the program allows residential (RS) or small commercial (GS) customers to voluntarily contribute funds for green energy, in any whole multiple of $5 each month. Each $5 contribution will allow the Companies to acquire 300 kWh of green energy in the form of RECs. RS and GS customers may withdraw from the program at any time.

All larger customers receiving service under special contract or any standard rate schedule other than RS or GS may contribute any whole multiple of $13 per month toward the purchase of green tags, representing the environmental attributes of 1,000 kWh of generation from a renewable resource. Large commercial and industrial customers must commit for one year at a time.

The cost structure for the larger customers is different from the RS and GS customers due to the reduced promotional and educational efforts needed for larger customers; the longer commitment period of the larger customers; and larger blocks of power that will be purchased by the larger customers.

The program is designed to be revenue neutral, with all revenues received to be expended for either REC purchases, or to cover program costs. The Companies selected 3 Phases Climate Solutions, LLC — a nationally recognized green energy marketer — to procure the necessary RECs for the program and perform other administrative functions required in the purchase of the RECs.

Approximately 75 percent of the RS and GS $5 contribution and 96 percent of every other customer's $13 contribution will be used to purchase RECs. The remainder will be applied to program promotion to increase enrollment. The Companies reserve the right to seek recovery of approximately $50,000 per year of unfunded program administration costs in future rate case proceedings.

Program enrollment initiatives and promotional activities are currently underway.

RFP Process

The Companies have used a Request for Proposals (RFP) process to obtain offers from the electric market for specific power needs. An RFP was issued in July 2007 for bids on renewable energy. The respondents could propose a power purchase agreement, renewable energy technology asset acquisition or an alternative deal structure. A total of 15 responses were received and all respondents were interviewed during October and November 2007. As a result of the interviews, a short list of respondents was compiled and further discussions are taking place. The Companies expect to report the results of the RFP to the Commission in summer of 2008.

RESEARCH AND DEVELOPMENT

FutureGen

On October 31, 2006, E.ON U.S., the parent company of LG&E and KU, announced that it committed $25 million to join the FutureGen Alliance. E.ON U.S. became the eleventh member of the alliance, which is a non-profit consortium of presently thirteen privately-owned leading international energy companies (spanning five continents) partnering with the U.S. Department of Energy (DOE) to site and develop FutureGen. In response to President Bush's directive to draw upon the best scientific research to address the issue of global climate change, FutureGen is an initiative to build the world's first integrated sequestration and hydrogen production research power plant. Following the Conceptual Design Phase the FutureGen plant net project cost is estimated at $1.8 billion. $300 million is offset by revenues from the plant and the remainder project cost is to be split 74 percent DOE funding and 26 percent FutureGen Alliance funding as defined in the Co-Operative Agreement between the two parties. This financial commitment is designed to help move near-zero emissions power production from concept to a commercial reality.[3]

One of the goals of this project includes gasifying enough coal to fully load a commercial scale 275-megawatt combined-cycle gas turbine platform while capturing and sequestering a minimum of one million metric tons of carbon dioxide annually. The process

[3] http://www.futuregenalliance.org/publications/fg_technology_overview082007.pdf , 9/13/07

converts the coal's carbon to synthesis gas comprised of mostly hydrogen and carbon monoxide. The synthesis gas then reacts with steam to produce additional hydrogen and a concentrated stream of carbon dioxide. In turn, this hydrogen will be used as clean fuel in applications such as electricity generation in turbines, fuel cells, or hybrid combinations of these technologies.

In 2007, the FutureGen Alliance underwent the site selection and preliminary design phases of the project. Initially, there were 12 sites proposed in seven states, with one of the sites being in Henderson County, Ky. Later, the list was reduced to four candidate sites competing for the FutureGen project: Jewett, Texas; Odessa, Texas; Tuscolla, Ill.; and Mattoon, Ill. The selected site is Mattoon, Ill. However, after announcing the site in December 2007, the DOE did not immediately approve the site, citing high costs. DOE eventually announced a restructured carbon capture and storage program that does not include specific funding for the existing FutureGen Alliance project. The CEO of the FutureGen Alliance Michael Mudd countered their claims and in February 2008 the members of the Alliance unanimously agreed that FutureGen at Mattoon remains in the public interest and the project should proceed to completion. The FutureGen Alliance (with support from E.ON U.S. intends to work with the Administration, Congress, and Illinois stakeholders to advance the project.

The Washington Group has been contracted to assist in the engineering design and key procurement during the Preliminary Design Phase. After the Preliminary Design Phase, the project will progress into the Detail Design Phase and finally the Construction Phase. If funded, the FutureGen Project is expected to have commercial operation in late 2012 or early 2013.

Greenhouse Gas Research

Other research and development projects of the Companies include efforts in reducing greenhouse gases. In April 2006, the University of Kentucky's Center for Applied Energy Research received a three-year, $1.5 million commitment from E.ON U.S. to study technology to reduce greenhouse gases. Also, the Companies are charter members of the Electric Power Research Institute's (EPRI) "Coal Fleet for Tomorrow" program. This program is a research effort founded with the goal of making a portfolio of advanced coal technologies more accessible and affordable for power producers and society.

ENVIRONMENTAL REGULATIONS

316(b) Regulation of cooling water intake structures

Since the 2005 IRP, portions of EPA's 316(b) regulation of cooling water intake structures was found to be illegal and remanded back to EPA for revision by the U.S. 2nd Circuit Court. Studies are continuing on the impacts of cooling water intakes on fish populations. EPA is reviewing another round of rulemaking.

Clean Air Interstate Rule

Since the 2005 IRP, the Clean Air Interstate Rule (CAIR) was issued as final. Through a cap-and-trade program, additional reductions in sulfur dioxide (SO_2) and nitrogen oxide (NO_x) are required to aid in the reduction of ozone and particulate matter levels. Planned installation of emission controls, flue gas desulphurization (FGD) and selective catalytic reduction (SCR) will aid compliance with the regulation.

Clean Air Mercury Rule

Since the 2005 IRP, the Clean Air Mercury Rule (CAMR) was issued as final and was subsequently vacated by the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit). This regulation was aimed at reducing mercury emissions from coal-fired electric generating units. As a cap-and-trade program, mercury emissions were to be reduced in two phases, beginning in 2010 and 2018. However, on February 8, 2008, the D.C. Circuit handed down a decision vacating CAMR. EPA will be determining what its next steps should be for regulating the emissions of these sources.

National Ambient Air Quality Standards

Eight-hour Ozone

Since the 2005 IRP, all areas of Kentucky have been designated in "attainment" with the current Eight-hour ozone standards. However, on March 12, 2008, EPA lowered the primary standard. Several counties in Kentucky are expected to be in "non-attainment". Regulations will need to be developed to control sources to meet the new standard.

$PM_{2.5}$

Since the 2005 IRP, EPA revised the 24-hour $PM_{2.5}$ standard, lowering it from 65 to 35$\mu g/m^3$. Jefferson County is believed to be only area in Kentucky that would be affected by this revision to the NAAQS. Regulations will need to be developed to control sources to meet this new standard.

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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, 2003-2007

	2003	2004	2005	2006	2007
Residential	393,112	398,093	403,943	409,612	413,747
Commercial	74,510	76,164	76,901	77,804	79,359
Industrial	1,973	1,933	1,903	1,883	1,855
Public Authority	7,028	7,151	7,209	7,174	7,135
Utility Use & Other*	1,485	1,487	1,472	1,470	1,460
Virginia Retail	29,629	29,811	29,914	29,965	29,956
Required Sales for Resale	13	13	12	12	12
Total Customers	507,750	514,652	521,354	527,920	533,524

* Includes Lighting

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

	2003	2004	2005	2006	2007
SYSTEM BILLED SALES:					
Recorded	19,470	20,074	20,994	20,831	21,625
Weather-Normalized	19,702	20,458	20,752	21,013	21,392
SYSTEM USED SALES:					
Recorded	19,496	20,178	20,990	20,675	21,643
Weather-Normalized	19,803	20,534	20,769	20,927	21,437
ENERGY REQUIREMENTS:					
Recorded	20,654	21,317	22,354	22,014	22,993
Weather-Normalized	20,961	21,673	22,119	22,282	22,774
SALES BY CLASS:					
Residential	5,594	5,762	6,178	5,908	6,432
Commercial	4,016	4,130	4,276	4,270	4,577
Industrial	5,594	5,880	6,004	6,083	6,050
Lighting	54	54	52	52	54
Public Authorities	1,428	1,466	1,514	1,473	1,552
Requirement Sales for Resale	1,903	1,959	2,014	1,978	2,058
KENTUCKY Retail	18,589	19,252	20,038	19,764	20,723
VIRGINIA Retail	906	926	952	910	919
System Losses	1,129	1,115	1,348	1,323	1,333
Utility Use	30	24	16	16	17
ENERGY REQUIREMENTS	20,654	21,317	22,354	22,014	22,993

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

	2003	2004	2005	2006	2007
SUMMER					
Recorded	3,810	3,744	4,079	4,207	4,344
Weather-Normalized	3,836	3,800	4,049	4,257	4,236
	2002/03	**2003/04**	**2004/05**	**2005/06**	**2006/07**
WINTER					
Recorded	3,944	3,768	4,065	4,019	4,300
Weather-Normalized	3,930	3,771	4,059	4,114	4,353

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

	2003	2004	2005	2006	2007
Energy Sales (GWh)	17,016	17,420	19,518	19,125	20,243
Coincident Peak Demand (MW)	3,810	3,744	4,079	4,200	4,298

7.(2)(e) KU Energy Sales and Peak Demand for Interruptible Customers

	2003	2004	2005	2006	2007
Energy Sales (GWh)	1,574	1,832	521	640	481
Coincident Peak Demand (MW)	0	0	0	7	46

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

	2003	2004	2005	2006	2007
Annual Energy Losses	1,129	1,115	1,348	1,323	1,333
Losses as Percent of Delivered Sales	5.8%	5.5%	6.4%	6.4%	6.2%

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)

	2003	2004	2005	2006	2007
Residential	14,230	14,474	15,295	14,423	15,546
Commercial	53,900	54,227	55,598	54,884	57,668
Industrial	2,835,250	3,041,785	3,155,018	3,230,462	3,261,175
Public Authority	203,225	205,065	210,025	205,255	217,554

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

	2003	2004	2005	2006	2007
Residential	29%	29%	29%	29%	30%
Commercial	21%	20%	20%	21%	21%
Industrial	29%	29%	29%	29%	28%
Public Authority	7%	7%	7%	7%	7%
Lighting	0%	0%	0%	0%	0%
Virginia Retail	5%	5%	5%	4%	4%
Required Sales for Resale	10%	10%	10%	10%	10%
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 2003, the total number of residential customers has increased at an average annual rate of 1.3 percent, while average annual use-per-customer has increased by an average annual rate of 1.7 percent 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	**1997**	**2003**	**2007**
Refrigerator	117	118	122
Freezer	44	52	43
Home Computer	33	48	54
Range	80	89	89
Microwave Oven	91	95	95
Dishwasher	59	59	58
Clothes Washer	86	91	84
Clothes Dryer (Electric)	80	87	88
Water Heater	59	76	61
Dehumidifier	13	16	11
Air Conditioning:			
Central A/C*	55	58	68
Room A/C	17	20	20
Primary Home Heating	39	47	51

* includes Heat Pump

KU Kentucky Retail Commercial Energy Sales

The KU's Kentucky retail commercial class has experienced modest growth in the number of customers and use-per-customer. From 2003 to 2007, the total number of customers has grown at an average annual rate of 1.6 percent. Use-per-customer has grown at an average annual rate of 1.5 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 2003, the number of customers in the industrial class has declined at an average annual rate of 1.5 percent. In spite of this decline, total sales to this class have increased by an average annual rate of 2 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 2003–2007 period.

KU Virginia Energy Sales

Virginia sales have demonstrated very low growth in recent years, increasing at an annual average rate of 0.4 percent since 2003. The total number of customers and use-per-customer (weather-normalized) grew at an average annual rate of approximately 0.2 percent over the 2003-2007 period.

KU Wholesale Energy Sales

Wholesale (municipal) weather-normalized sales have grown at an annual average rate of 1.4 percent since 2003. 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)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Residential	6,295	6,379	6,471	6,565	6,656	6,727	6,779	6,807	6,874	6,953	7,059	7,154	7,275	7,386	7,492
Commercial	4,556	4,625	4,689	4,769	4,836	4,915	4,979	5,052	5,116	5,194	5,267	5,340	5,436	5,507	5,603
Industrial	6,637	6,773	6,882	7,006	7,107	7,154	7,203	7,298	7,370	7,438	7,560	7,672	7,802	7,890	7,992
Total C/I	11,193	11,398	11,571	11,775	11,943	12,069	12,182	12,351	12,486	12,631	12,827	13,012	13,238	13,398	13,595
Public Authority	1,579	1,608	1,640	1,679	1,716	1,747	1,778	1,811	1,842	1,875	1,906	1,935	1,970	2,002	2,037
Lighting	55	56	57	58	58	59	60	61	62	63	63	64	65	66	67
Req. Sales for Resale	2,056	2,081	2,104	2,126	2,148	2,169	2,190	2,212	2,233	2,256	2,278	2,301	2,323	2,346	2,369
Total Kentucky	21,178	21,521	21,844	22,203	22,522	22,772	22,990	23,241	23,497	23,778	24,134	24,466	24,872	25,197	25,559
Virginia	964	973	980	990	998	1,005	1,009	1,012	1,016	1,023	1,031	1,039	1,048	1,055	1,064
Total KU Calendar Sales	22,141	22,494	22,823	23,192	23,519	23,775	23,998	24,252	24,512	24,799	25,163	25,504	25,918	26,252	26,623
Utility Use & Losses	1,372	1,395	1,415	1,439	1,460	1,479	1,498	1,521	1,542	1,562	1,585	1,607	1,632	1,653	1,676
Total Requirements	23,514	23,889	24,239	24,631	24,981	25,255	25,497	25,774	26,055	26,362	26,749	27,112	27,552	27,906	28,300

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

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Summer	4,306	4,371	4,428	4,496	4,560	4,615	4,669	4,736	4,799	4,861	4,933	5,001	5,082	5,149	5,223
	08/09	**09/10**	**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**
Winter	4,188	4,253	4,322	4,383	4,430	4,468	4,510	4,556	4,608	4,676	4,786	4,818	4,880	4,919	5,005

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	**2008**	712	580	546	425	397	485	597	612	480	395	435	630	6,295
	2009	723	591	554	431	403	491	599	618	486	400	442	640	6,379
Commercial	**2008**	384	327	341	318	367	410	458	457	382	372	354	386	4,556
	2009	389	330	347	323	371	415	469	465	386	378	359	392	4,625
Industrial	**2008**	522	507	537	512	583	577	578	585	527	555	570	585	6,637
	2009	532	517	547	521	593	589	590	597	539	567	583	598	6,773
Public Authority	**2008**	127	113	117	115	125	143	155	156	144	135	120	128	1,579
	2009	129	115	119	117	127	145	159	159	147	138	123	130	1,608
Lighting	**2008**	5	5	5	4	4	4	4	4	4	5	5	6	55
	2009	5	5	5	4	4	4	4	4	5	5	5	6	56
Sales for Resale	**2008**	171	165	159	148	162	187	207	202	171	154	159	172	2,056
	2009	173	167	161	150	164	189	209	204	173	156	161	174	2,081
		=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	======
Total Kentucky	**2008**	1,921	1,697	1,706	1,523	1,637	1,805	1,999	2,017	1,708	1,616	1,643	1,907	21,178
	2009	1,951	1,725	1,733	1,547	1,662	1,834	2,030	2,048	1,736	1,644	1,672	1,939	21,521
Virginia	**2008**	108	92	90	73	71	72	73	74	63	68	80	101	964
	2009	109	92	91	73	72	73	73	75	64	68	81	102	973
Total Calendar Sales Forecast	**2008**	2,028	1,789	1,795	1,595	1,708	1,877	2,072	2,091	1,771	1,684	1,723	2,008	22,142
	2009	2,060	1,817	1,823	1,621	1,734	1,907	2,103	2,122	1,800	1,712	1,753	2,042	22,495
Total Requirements	**2008**	2,154	1,899	1,907	1,694	1,814	1,993	2,200	2,220	1,881	1,788	1,830	2,133	23,514
	2009	2,188	1,930	1,936	1,721	1,842	2,025	2,233	2,254	1,912	1,818	1,862	2,168	23,889

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 and peak demand 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 2022.

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 (GI), a respected and nationally recognized economic consulting firm used by many utilities.

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 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.

Mine Power sales are forecast using a coal production forecast for Eastern and Western Kentucky obtained from Hill & Associates.

Weather records are also a vital input to electricity sales forecasting. KU receives its weather data from the National Climatic Data Center (NCDC), a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. For the forecast period (2008-2022), averages of cooling and heating degree days based on the 20-year period ending in 2006 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

- *Demographics:* The population growth rate in the KU service territory was forecasted to be below the national average. Annual population growth was forecast to average 0.6 percent over the next 10 years and 0.8 percent nationally; a continuation of past trends where population growth in Kentucky has lagged the national average. Furthermore, the aging population leads to fewer people per household. The number of households was forecast to increase at a 0.7 percent annual rate over the next 10 years.

- *Output:* Real Gross State Product (RGSP) for the state of Kentucky was forecasted to grow by approximately 2.5 percent annually over the forecast period.

- *Employment:* Overall employment was forecast to grow at approximately 0.8 percent per year over the forecast period.

- *Personal Income:* Real total personal income in the KU service territory was forecast to grow at a 2.6 percent average annual rate for the first 10 years, and at 2 percent annually over the next 10 years.

Energy Independence and Security Act of 2007

The Energy Independence and Security Act of 2007 (ESA 2007) was signed into law by President Bush in December 2007. The provisions in ESA 2007 are primarily designed to increase energy efficiency and the availability of renewable energy. LG&E and KU electricity sales will be impacted primarily by a set of provisions in the law that tighten lighting and appliance efficiency standards as well as foster the development of new building and commercial equipment standards.

The 2008 IRP incorporates the impact of the new lighting and appliance efficiency standards on electricity sales (new building and commercial equipment standards have not been developed, so the potential impact of these standards has not been incorporated). The new lighting efficiency standards are expected to have the greatest impact on electricity sales. The full impact of the new lighting standards is expected to be phased in gradually between 2012 and

2019. Because LG&E and KU already assume appliances will become more efficient in the future, the impact of the new appliance efficiency standards is not as significant. A more detailed discussion of ESA 2007 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 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.

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 adjusted for company uses and losses. The resulting estimate of monthly energy requirements is then associated with a typical load profile and load factor 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 2007 was 85.8 percent Kentucky-retail, 4.7 percent Virginia-retail, and 9.5 percent wholesale (FERC jurisdiction).

KU's sales forecast is comprised of 21 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)

Year	Residential	Commercial	Industrial	Mine Power	Req. Sales for Resale	Lighting	Virginia Retail	Total KU
2008	6,283	1,938	10,172	574	2,056	126	965	22,114
2009	6,369	1,972	10,379	568	2,081	128	975	22,472
2010	6,460	2,005	10,568	556	2,104	130	982	22,806
2011	6,553	2,044	10,775	550	2,126	132	991	23,172
2012	6,645	2,076	10,953	548	2,148	134	1,000	23,504
2013	6,716	2,112	11,081	540	2,169	136	1,006	23,761
2014	6,768	2,139	11,198	541	2,190	138	1,011	23,985
2015	6,795	2,165	11,324	585	2,212	139	1,014	24,233
2016	6,863	2,192	11,444	606	2,233	141	1,018	24,497
2017	6,942	2,227	11,572	618	2,256	143	1,025	24,782
2018	7,048	2,262	11,695	684	2,278	145	1,033	25,146
2019	7,142	2,298	11,811	744	2,301	147	1,041	25,484
2020	7,264	2,343	11,967	800	2,323	149	1,050	25,898
2021	7,377	2,379	12,095	831	2,346	151	1,058	26,236
2022	7,482	2,425	12,240	870	2,369	153	1,067	26,605

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 a Statistically-Adjusted End-Use (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 two commercial forecast models: KU general service/LP secondary and KU all-electric schools (AES).

KU General Service/LP Secondary

The KU general service/LP secondary forecast includes all customers on the KU general service (GS) rate schedule and the KU large power service (LP) rate schedule that take service at the secondary distribution voltage. As a result of the 2004 rate case, a number of accounts in the LP secondary rate class were moved into the GS rate class. For this reason, the KU GS and KU LP secondary rate classes were forecasted together. Monthly usage was forecasted as a function of the average cost of electric service (the 'price' of electricity), Kentucky's Real Gross State Product, and weather-related binary variables. An AR(1) term is included to correct for any bias that may result from serial correlation.

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 five forecast models. Each of these models is discussed in more detail in the following sections.

LP Primary

The LP primary forecast includes all customers on the LP rate schedule that take service at the primary distribution voltage. Sales to LP primary customers were modeled as a function of the average cost of electric service in the industrial revenue class (the 'price' of electricity) and the Industrial Production Index. An AR(1) term is included to correct for any bias that may result from serial correlation, which is typical in time series data.

LP Transmission

The LP transmission forecast includes the single customer on the large power service rate schedule that takes service at transmission voltages. The LP transmission forecast was held flat at 2006 levels.

Large Industrial Time-of-Day (LITOD)

The "large industrial time-of-day (LITOD) forecast includes one customer on the LITOD rate schedule. The LITOD forecast through 2012 is developed based on discussions with that customer. In 2012, sales to this customer are forecasted to be two times the customer's 2004 usage levels.

LCI-TOD Primary

The "large commercial/industrial time-of-day (LCI-TOD) primary forecast includes all customers on the LCI-TOD rate schedule that take service at the primary distribution voltage. Sales to LCI-TOD primary customers are modeled as a function of the U.S. Industrial Production Index, the average cost of electric service (the 'price' of electricity), and weather.

LCI-TOD Transmission

The LCI-TOD transmission forecast consists of four Major Account customers on the large commercial/industrial time-of-day rate schedule that take service at transmission voltages. The LITOD forecast through 2012 was developed based on discussions with each of these customers. The growth in the forecast is driven almost entirely by anticipated increases in one customer.

KU Mine Power Forecast Group

The KU mine power forecast group includes two forecast models: mine power primary and mine power transmission. Each of these models is discussed in more detail in the following sections.

Mine Power Primary

The mine power primary forecast includes all customers on the coal mining power service (MP) rate schedule who take service at the primary distribution voltage. Sales to mine power primary customers are modeled as a function of coal production in the Central Appalachian and Illinois Basin mining regions.

Mine Power Transmission

The mine power transmission forecast includes all customers on the coal mining power service (MP) rate schedule who take service at transmission voltages. Sales to mine power transmission customers are modeled as a function of coal production in the Central Appalachian and Illinois Basin mining regions.

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 on rate schedule WPS-87(M) 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 on the rate schedule WPS-87(M) 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 2005 levels, and the number of fixtures was forecasted by trending.

ODP Sales Forecasts

The Old Dominion Power Company (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 a "Statistically-Adjusted End-Use" (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.

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

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. ODP general service sales were forecasted as the product of a use-per-customer forecast and a forecast of the number of customers. Use-per-customer was forecasted as a function of weather, the number of residential customers, the industrial production index, and electricity prices. The number of customers was forecasted as a function of the number of residential customers.

ODP Large Power Forecast

The ODP large power forecast includes customers on the large power service rate schedule. Large power sales were forecasted as a function of heating degree-days, value-added for the mining industries and the U.S. Industrial Production index.

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 2008 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 5 percent higher (roughly 1,300 GWh and 240 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 5 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.

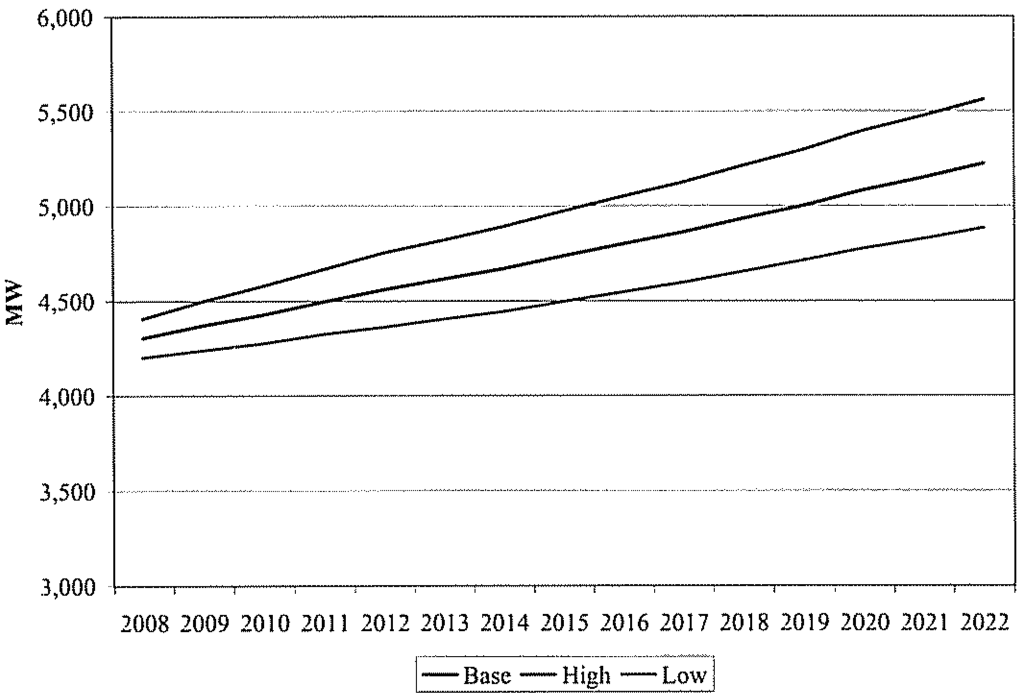
Table 7.(7)(e)-1
KU Base, High, and Low Energy Requirements Forecasts (GWh)

Year	Base IRP	High	Low
2008	23,514	24,065	22,956
2009	23,889	24,592	23,179
2010	24,239	25,070	23,414
2011	24,631	25,566	23,697
2012	24,981	26,040	23,904
2013	25,255	26,384	24,109
2014	25,497	26,714	24,260
2015	25,774	27,066	24,455
2016	26,055	27,430	24,675
2017	26,362	27,810	24,914
2018	26,749	28,281	25,223
2019	27,112	28,727	25,537
2020	27,552	29,271	25,872
2021	27,906	29,695	26,140
2022	28,300	30,150	26,446

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

Year	Base IRP	High	Low
2008	4,306	4,407	4,204
2009	4,371	4,500	4,241
2010	4,428	4,580	4,277
2011	4,496	4,667	4,325
2012	4,560	4,753	4,363
2013	4,615	4,821	4,405
2014	4,669	4,892	4,443
2015	4,736	4,972	4,495
2016	4,799	5,051	4,547
2017	4,861	5,125	4,596
2018	4,933	5,213	4,654
2019	5,001	5,296	4,713
2020	5,082	5,396	4,775
2021	5,149	5,476	4,826
2022	5,223	5,561	4,884

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 company is considering two enhancements to its forecasting process. First, the company is considering utilizing an SAE model, much like the existing residential SAE model, to develop its commercial forecasts. The purpose for this change would be to develop the ability to better incorporate changes in commercial end-uses – particularly end-use changes related to energy efficiency.

The second change is related to the way the Company develops its hourly demand forecast. Currently, total energy for each utility is allocated to hours based on an average 10-year load duration curve. The use of a representative load duration curve removes the risk – inherent in the application of any single historical year – of replicating an anomalous pattern over the forecast period and results in a more consistent relationship between monthly peak demands. The use of average values over the last 10 years also captures the impact of the existing trend in system load factor.

In the future, the company will consider checking its hourly demand forecast against coincident class-specific hourly demand forecasts. This approach will enable 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 October 2007, KU and LG&E conducted a residential appliance saturation survey. The last such survey was conducted in 2003. Although the 2007 survey was undertaken after the date of preparation of the 2008 IRP forecast, the results from the survey broadly confirmed the assumptions regarding appliance saturations incorporated in the forecast. The Companies also participate in an Energy Forecaster's Group (EFG) 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, 2003-2007

	2003	2004	2005	2006	2007
Residential	337,768	342,188	346,164	349,821	352,699
Small Commercial	38,531	38,340	38,103	38,721	39,326
Large Commercial	2,432	2,463	2,509	2,511	2,546
Industrial	410	399	398	398	393
Utility Use & Other*	3,514	3,516	3,489	3,458	3,429
Public Authority	2,283	2,290	2,335	2,422	2,310
Total Customers	384,938	389,196	392,998	397,331	400,703

*Includes lighting.

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

	2003	2004	2005	2006	2007
SYSTEM BILLED SALES:					
Recorded	11,448	11,698	12,186	12,010	12,669
Weather Normalized	11,655	11,735	11,965	12,151	12,198
SYSTEM USED SALES:					
Recorded	11,503	11,724	12,292	11,965	12,658
Weather Normalized	11,715	11,744	11,940	12,136	12,268
ENERGY REQUIREMENTS:					
Recorded	12,123	12,480	13,022	12,724	13,395
Weather Normalized	12,335	12,500	12,650	12,905	12,984
SALES BY CLASS:					
Residential	3,835	3,924	4,265	4,018	4,486
Small Commercial	1,263	1,282	1,333	1,319	1,428
Large Commercial	2,219	2,251	2,349	2,295	2,409
Industrial	2,936	3,019	3,077	3,068	2,992
Public Authorities	1,181	1,179	1,204	1,205	1,282
Lighting	69	69	64	61	60
TOTAL LG&E SALES	11,503	11,724	12,292	11,965	12,658
System Losses	620	756	679	744	751
Utility Use	22	24	24	23	24
ENERGY REQUIREMENTS	12,123	12,480	13,022	12,724	13,395

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

	2003	2004	2005	2006	2007
SUMMER					
Recorded	2,583	2,485	2,754	2,729	2,834
Normalized	2,612	2,562	2,685	2,784	2,775
	2002/03	**2003/04**	**2004/05**	**2005/06**	**2006/07**
WINTER					
Recorded	1,824	1,750	1,787	1,817	1,885
Normalized	1,769	1,792	1,815	1,838	1,861

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

	2003	2004	2005	2006	2007
Energy Sales (GWh)	10,874	11,251	11,764	11,416	12,169
Coincident Peak Demand (MW)	2,530	2,458	2,704	2,680	2,834

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

	2003	2004	2005	2006	2007
Energy Sales (GWh)	629	473	528	550	488
Coincident Peak Demand (MW)	26	27	50	49	0

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

	2003	2004	2005	2006	2007
Annual Energy Losses	620	756	679	744	751
Losses as Percent of Delivered Sales	5.4%	6.4%	5.5%	6.2%	5.9%

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 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)

	2003	2004	2005	2006	2007
Residential	11,353	11,467	12,321	11,485	12,720
Small Commercial	32,779	33,438	34,984	34,059	36,312
Large Commercial	912,418	913,926	936,230	914,082	946,190
Industrial	7,160,976	7,566,416	7,731,156	7,707,676	7,613,232
Public Authority	517,302	514,847	515,632	497,393	554,978

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

	2003	2004	2005	2006	2007
Total Residential	33%	33%	35%	34%	35%
Small Commercial	11%	11%	11%	11%	11%
Large Commercial	19%	19%	19%	19%	19%
Industrial	25%	26%	25%	26%	24%
Public Authority	10%	10%	10%	10%	10%
Lighting	1%	1%	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 2003, the total number of residential customers has increased at an average annual rate of 1.1 percent, while average annual use-per-customer has risen less than 1 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	1999	2003	2007
Refrigerator	100	100	100
Freezer	42	45	34
Home Computer	-	62	65
Range	-	79	71
Microwave Oven	-	93	91
Dishwasher	61	66	58
Clothes Washer	-	88	87
Clothes Dryer (Electric)	-	76	78
Water Heater	-	29	17
Dehumidifier	-	14	15
Air Conditioning:	-		
Central A/C*	81	81	89
Room A/C	-	13	13
Primary Home Heating	-	25	20

* includes Heat Pump

LG&E Small Commercial Energy Sales

Weather-normalized sales to the small commercial class have grown since 2003 at an average annual rate of 1.8 percent. This growth has been driven primarily by growth in use-per-customer. On a weather-normalized basis, small commercial use-per-customer has grown at an average annual rate of 1.3 percent since 2003. The number of customers has grown from 38,531 customers in 2003 to 39,326 in 2007 – an average annual growth rate of 0.5 percent.

LG&E Large Commercial Energy Sales

Sales to the large commercial class have increased at an average annual rate of 0.7 percent on a weather-normalized basis since 2003. Unlike the small commercial class, the growth in large commercial sales has been driven primarily by growth in the number of customers. Since 2003, use-per-customer for the large commercial class has declined at an average annual rate of 0.5 percent. The number of customers has grown at an average annual rate of 1.2 percent.

LG&E Industrial Energy Sales

Energy sales to LG&E's industrial class have remained fairly constant over the 2003-2007 period. The decline in the number of industrial customers over this period was offset by an increase 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)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Residential	4,263	4,320	4,386	4,450	4,507	4,545	4,576	4,587	4,620	4,673	4,750	4,821	4,907	4,979	5,053
Small Commercial	1,372	1,394	1,416	1,440	1,461	1,480	1,498	1,515	1,534	1,555	1,579	1,603	1,626	1,646	1,670
Large Commercial	2,463	2,523	2,582	2,641	2,699	2,754	2,808	2,857	2,900	2,949	3,000	3,056	3,115	3,171	3,233
Industrial	3,168	3,186	3,170	3,196	3,226	3,266	3,282	3,273	3,269	3,271	3,277	3,280	3,287	3,293	3,298
Public Authority	1,260	1,286	1,314	1,345	1,367	1,384	1,402	1,419	1,434	1,450	1,466	1,483	1,501	1,517	1,536
Lighting	63	63	63	63	64	64	64	64	64	64	64	64	64	64	64
	====	====	====	====	====	====	====	====	====	====	====	====	====	====	====
Total LG&E Calendar Sales	12,590	12,773	12,931	13,136	13,324	13,493	13,631	13,714	13,820	13,962	14,135	14,308	14,500	14,671	14,854
Utility Use & Losses	731	742	751	764	776	787	799	810	820	830	840	851	862	872	883
Total Requirements	13,321	13,514	13,682	13,900	14,099	14,280	14,430	14,524	14,640	14,791	14,975	15,158	15,362	15,543	15,737

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

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Summer	2,789	2,817	2,862	2,908	2,952	2,995	3,038	3,075	3,113	3,152	3,194	3,236	3,282	3,324	3,368
	08/09	**09/10**	**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**
Winter	1,876	1,894	1,924	1,953	1,979	1,999	2,006	2,034	2,057	2,081	2,086	2,112	2,162	2,125	2,214

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	**2008**	356	293	305	260	305	404	524	528	390	287	264	346	4,263
	2009	362	299	310	264	310	410	527	533	395	291	269	351	4,320
Small Commercial	**2008**	107	95	101	97	117	133	147	147	113	105	100	112	1,372
	2009	108	96	103	98	118	135	150	149	114	106	101	113	1,394
Large Commercial	**2008**	193	166	182	177	215	242	262	256	197	191	185	198	2,463
	2009	197	170	186	181	220	247	270	263	202	195	189	202	2,523
Industrial	**2008**	248	248	249	252	270	269	280	288	279	260	264	261	3,168
	2009	253	254	256	257	276	277	280	283	275	257	260	258	3,186
Public Authority	**2008**	99	89	93	92	107	117	124	128	111	100	97	102	1,260
	2009	100	90	94	94	109	120	128	132	114	103	98	103	1,286
Lighting	**2008**	7	6	6	5	5	4	4	5	5	6	6	6	63
	2009	7	6	6	5	5	4	4	5	5	6	6	6	63
		======	======	======	======	======	======	======	======	======	======	======	======	======
Total LG&E Calendar Sales	**2008**	1,009	898	936	882	1,019	1,170	1,341	1,351	1,095	949	916	1,024	12,590
	2009	1,028	915	955	899	1,038	1,192	1,359	1,365	1,106	959	924	1,034	12,773
Requirements	**2008**	1,068	950	991	933	1,078	1,237	1,419	1,430	1,159	1,004	969	1,083	13,321
	2009	1,087	968	1,011	951	1,098	1,261	1,438	1,444	1,170	1,014	978	1,094	13,514

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 and peak demand 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.

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

- *Demographics:* Population in the Louisville area was forecast to increase at a slower rate than the national population forecast. Annual population growth was forecast to average 0.7 percent over the next five years as well as over the 15-year forecast horizon. Furthermore, with the aging of the population (resulting in fewer persons per household), households numbers were forecast to increase at a faster rate than population – 1.1 percent per year on average over the next five years and 1.0 percent over the full 15-year forecast horizon.

- *Output:* Real Gross State Product for the state of Kentucky was forecast to grow by approximately 2.5 percent annually over the forecast period. Although LG&E's service territory is small geographically relative to the state, large employers in the service territory, like Ford and UPS, are significant contributors to the index.

- *Employment:* Overall employment was forecast to grow at approximately 0.7 percent per year over the forecast period.

- *Personal Income:* Real total personal income was forecast to increase at a 2.9 percent average annual rate over the first five years and at a 2.8 percent growth rate over the 15-year forecast horizon.

Energy Independence and Security Act of 2007

The Energy Independence and Security Act of 2007 (ESA 2007) was signed into law by President Bush in December 2007. The provisions in ESA 2007 are primarily designed to increase energy efficiency and the availability of renewable energy. LG&E and KU electricity sales will be impacted primarily by a set of provisions in the law that tighten lighting and appliance efficiency standards as well as foster the development of new building and commercial equipment standards.

The 2008 IRP incorporates the impact of the new lighting and appliance efficiency standards on electricity sales (new building and commercial equipment standards have not been developed, so the potential impact of these standards has not been incorporated). The new lighting efficiency standards are expected to have the greatest impact on electricity sales. The full impact of the new lighting standards is expected to be phased in gradually between 2012 and 2019. Because LG&E and KU already assume appliances will become more efficient in the future, the impact of the new appliance efficiency standards is not as significant. A more detailed discussion of ESA 2007 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 nine 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

Year	Residential	Commercial	Industrial	Lighting	LG&E Total
2008	4,259	4,785	3,471	63	12,578
2009	4,317	4,884	3,498	63	12,762
2010	4,382	4,983	3,493	63	12,921
2011	4,446	5,084	3,532	63	13,125
2012	4,503	5,180	3,567	64	13,313
2013	4,541	5,271	3,606	64	13,482
2014	4,571	5,360	3,623	64	13,618
2015	4,582	5,442	3,614	64	13,703
2016	4,615	5,520	3,611	64	13,810
2017	4,668	5,606	3,613	64	13,951
2018	4,744	5,696	3,619	64	14,123
2019	4,816	5,794	3,622	64	14,295
2020	4,902	5,891	3,630	64	14,486
2021	4,975	5,986	3,636	64	14,661
2022	5,047	6,089	3,641	64	14,842

LG&E Residential Forecast

The LG&E 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.

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

Please see section 7.(7)(c), KU Residential Use-per-Customer Forecast, for a description of the SAE model.

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. LG&E small commercial sales were forecasted as the product of a use-per-customer forecast and a forecast of the number of customers. Observation of the historical use-per-customer series revealed that, while there have been some fluctuations in the values, the series has been essentially flat. Therefore, use-per-customer was modeled as a function of weather since 2000, with binaries used to correct for outliers in the historical series. There was no growth trend figured into the forecast, so use-per-customer is forecasted to remain flat over the entire forecast period, with monthly variations because of seasonality.

The monthly number of customers was modeled as a function of residential customers, along with a trend term that starts in October 2004, to account for a flattening out of growth.

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 as the product of a use-per-customer forecast and a forecast of the number of customers. Large commercial use-per-customer has been essentially flat over the past several years. Therefore, use-per-customer was modeled as a function of weather since 1998.

The monthly number of customers was modeled as a function of residential customers. The customer model included an AR(1) term to correct for any bias that may result from serial correlation.

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. Each of these models is discussed in more detail in the following sections.

LP Power

The LP power forecast includes all customers on the large power industrial service (LP) rate schedule. Monthly sales are modeled as a function of the U.S. Industrial Production Index, the cost of service provision (the 'price' of electricity), and weather binary variables to account for summer cooling load (June – September).

LP-TOD/Special Contract

The LP-TOD/special contract forecast includes all customers on the large power industrial – time-of-day rate schedule and all special contract customers. Major Accounts make up approximately 70 percent of the total energy usage in this forecast. With the exception of some growth in Major Account usage, energy usage for the combined group has been fairly flat. The forecast of energy usage for this group in total is modeled as a regression of the Industrial Production Index, the cost of service provision ('price' of electricity), and cooling degree days in the summer months (June – September). An AR(1) term was included to correct for serially correlated errors, which is typical in time series data.

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 2005 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.

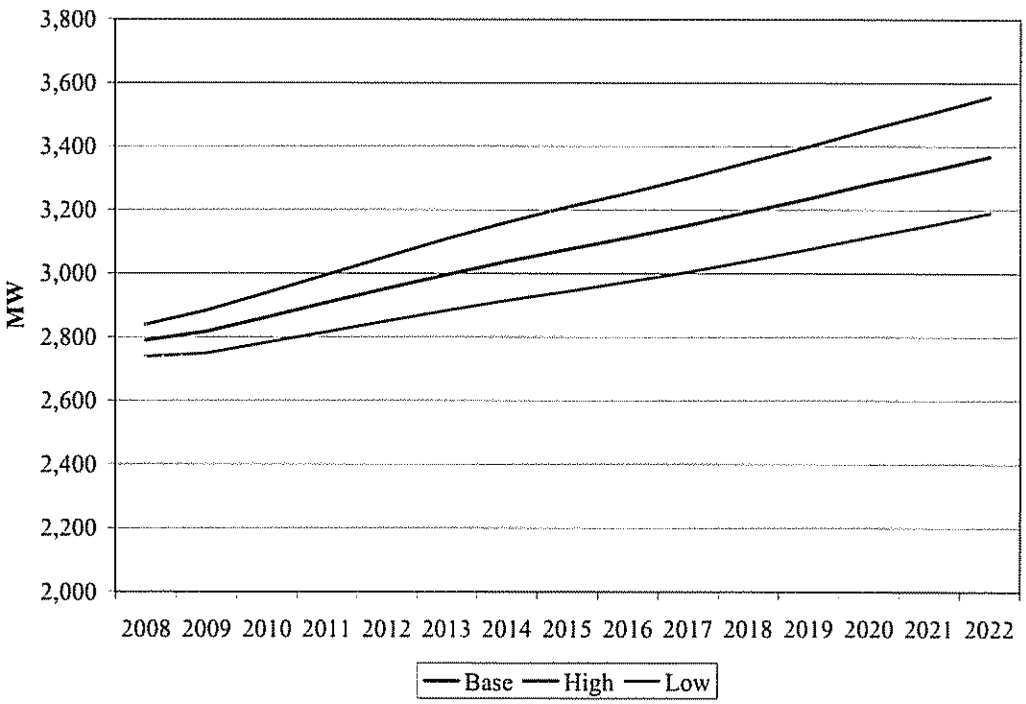
Table 7.(7)(e)-1
LG&E Base, High, and Low Energy Requirements Forecasts (GWh)

Year	Base IRP	High	Low
2008	13,321	13,559	13,081
2009	13,514	13,832	13,190
2010	13,682	14,049	13,305
2011	13,900	14,317	13,460
2012	14,099	14,578	13,612
2013	14,280	14,819	13,745
2014	14,430	15,018	13,846
2015	14,524	15,163	13,896
2016	14,640	15,309	13,980
2017	14,791	15,497	14,091
2018	14,975	15,722	14,241
2019	15,158	15,938	14,398
2020	15,362	16,180	14,568
2021	15,543	16,398	14,727
2022	15,737	16,628	14,892

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

Year	Base IRP	High	Low
2008	2,789	2,839	2,739
2009	2,817	2,883	2,749
2010	2,862	2,939	2,783
2011	2,908	2,996	2,816
2012	2,952	3,053	2,850
2013	2,995	3,109	2,883
2014	3,038	3,161	2,915
2015	3,075	3,209	2,944
2016	3,113	3,253	2,974
2017	3,152	3,300	3,005
2018	3,194	3,351	3,039
2019	3,236	3,400	3,076
2020	3,282	3,454	3,115
2021	3,324	3,503	3,152
2022	3,368	3,556	3,190

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.

In developing this resource plan, considerable flexibility was maintained in order to respond to continuously changing conditions and yet provide adequate reliability now and in the future. As shown year-by-year in Section 8.(4), the plan provides dates for specific resource acquisitions. Changes in assumptions, technology, market conditions and customer needs are inevitable with the ongoing process of resource planning. This robust Integrated Resource Plan (IRP) represents one case or snapshot in time along a dynamic continuum of an ongoing 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 performed a study to determine an optimal reserve margin criterion to use. This study indicated that an optimal target reserve margin in the range of 13 to 15 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 maintained a reserve margin target of 14 percent. Additional detail on the development of this criterion is contained in the report titled *2008 Analysis of Reserve Margin Planning Criterion* (March 2008) contained in Volume III, Technical Appendix.

Existing capacity resources are composed of KU- and LG&E-owned generating units and two firm purchase power agreements: Owensboro Municipal Utilities (OMU) and Ohio Valley Electric Corporation (OVEC). Additionally, to help meet reserve margins, a firm purchase agreement has been established with Dynegy for 165 MW from their Bluegrass Unit 1 for June through September of 2008 and 2009 for peaking capacity.

As part of this IRP process, the Companies review the technological status, construction aspects, operating costs, and environmental features of various generation plant construction options. After screening many supply-side technologies, six 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* (April 2008) contained in Volume III, Technical Appendix. Strategist® is a proprietary, state-of-the-art resource planning computer model, developed by Ventyx Energy, LLC[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.

In addition to these supply-side options, several DSM programs that passed the screening analysis were also included in the integrated analysis. The base case IRP recommends the construction of two Greenfield combined-cycle combustion turbines (one in 2015 and one in

[1] Formerly Strategist® was a NewEnergy product. NewEnergy Associates was acquired by Ventyx on 8/31/2007.

2019), and one Greenfield simple-cycle combustion turbine in 2022. Additionally, there is the implementation of several new DSM programs which combine for an incremental initiative of 441 MW for a total DSM of 567 MW by 2016. Section 8.(5)(c) summarizes the study in more detail.

Changing Legislation

The Energy Independence and Security Act of 2007 (ESA 2007) was signed into law by President Bush on December 19, 2007. The provisions in ESA 2007 are primarily designed to increase energy efficiency and the availability of renewable energy. LG&E and KU electricity sales will be impacted primarily by a set of provisions in the law that tighten lighting and appliance efficiency standards as well as foster the development of new building and commercial equipment standards.

The 2008 IRP incorporates the impact of the new lighting and appliance efficiency standards on electricity sales (new building and commercial equipment standards have not been developed, so the potential impact of these standards has not been incorporated). The new lighting efficiency standards are expected to have the greatest impact on electricity sales. Because LG&E and KU already assume appliances will become more efficient in the future, the impact of the new appliance efficiency standards is not as significant.

Future impacts to energy requirements resulting from legislative changes are uncertain. Potential legislative actions regarding carbon emissions are particularly uncertain. The Companies will continue to monitor these developments moving forward.

In July 2006, the Federal Energy Regulatory Commission (FERC) certified the North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization.

Resultant from that, the NERC required mandatory compliance with the Reliability Standards as approved and established for electric utilities by the FERC effective June 18, 2007. Thus far, FERC has approved over 90 Mandatory Reliability Standards established by the NERC. Compliance with these standards includes plans for each region and utility that assures reliability of electricity across the national grid. The Companies are continuing to evaluate and assess their internal processes and practices in order to achieve a high level of consistency with the Reliability Standards.

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.

With two exceptions, the Companies' continue to plan three-week boiler outages each year to keep their units running efficiently through the year. The exceptions apply to the Trimble County and Mill Creek units, which are now subject to biennial four-week outages. Additionally, the Mill Creek units are scheduled off for one-week outages in the offsetting years. The target seven-year cycle for performing major maintenance continues to be successful for the Companies. 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 units, namely Trimble County Unit 1 and OMU's Smith Units 1 and 2. Since 75 percent of Trimble County Unit 1 is owned by LG&E, LG&E is given preference as to when Trimble County Unit 1 outages are scheduled. Joint owners Illinois Municipal Electric Agency (IMEA) and Indiana Municipal Power Agency (IMPA), 12.12 percent and 12.88 percent ownership respectively, are then informed of any schedule changes. The scheduling of outages for the OMU units is handled slightly differently. OMU informs the Companies as to the duration of outage needed on Smith Units 1 and 2, as well as the frequency of major overhauls. Then, the Smith unit outages are optimized together with the Companies' unit outages and schedules are checked with OMU prior to the schedule becoming the approved budget schedule.

Efficiency Improvements

Since the Companies' 2005 IRP, the Companies have proceeded with several activities that have improved generation efficiencies. These have included the latest controls technologies, boiler tube replacements, pulverizer repairs, precipitator rebuilds, and cooling tower rebuilds.

The most proven application for improving the efficiency of generating stations has been the installation of new process control technologies. New control technologies allow for tighter control of key operating parameters and provide for optimization of integrated systems not previously available with analog controls. Distributive control systems (DCS) have been added to or improved on Trimble County Unit 1, Brown Units 1 and 3, Green River Unit 3, and Ghent Unit 3. Several state-of-the-art transmitters and controllers have replaced pneumatic positioners and other antiquated controls. These improvements give much tighter control and provide more operational information, resulting in faster response and higher efficiency.

Boiler tube failures continue to be the largest contributor to the fleet's equivalent forced outage rate (EFOR). As native load has increased, so has the demand upon boiler load. Though equipment is aging, units are still required to run at peak capacity. To ensure maximum availability, boiler tube inspections and continuous boiler tube studies have been conducted, using the latest software and inspection technology equipment, to identify boiler sections which need replacement. In an effort to reduce forced outages due to welding issues, multiple employees across the fleet have been trained in welding inspection certification classes. All units across the fleet have had scheduled boiler outages as part of our routine maintenance program to replace boiler tube sections. These efforts will ensure maximum boiler availability and reliability.

The changes in coal supply and coal burner modifications to reduce gaseous emissions have negatively impacted precipitator (ESP) performance. To ensure compliance to particulate emission standards, a number of units had ESP rebuilds prior to 2005. To continue to improve on particulate emissions, several ESPs have had control upgrades to provide tighter control and reduce section outages. The ESPs on the following units have had control upgrades: Cane Run units, Mill Creek units, Brown Unit 2, and Green River Units 3 and 4. These efforts have reduced incidences of load restriction initiated to maintain opacity emission compliance.

Other efforts to increase efficiency and reduce unit derates have been pulverizer repairs, cooling tower refills, byproduct handling, air heater repairs, air compressor replacements, and both condenser tube testing and replacement. Pulverizer repairs performed throughout the fleet increase the efficiency and reduce unit derates. Aging cooling towers have been rebuilt using modern polymer technology and fill design to ensure availability and improve heat transfer. The rebuilds have included Brown Unit 1, Mill Creek Unit 3, and Trimble County Unit 1. Cane Run and Brown ash pond dikes have been raised to accommodate more by-products material. A combination of creative selling of byproducts and the vertical extension of pond dikes will extend the life of the ponds, thereby assisting in the effort to control generation costs. Replacement of air heater baskets on units across the fleet has improved heat transfer and reduced the risk of forced outages or derates. Inspection of these units had identified age-related corrosion and additional wear due to boiler changes (for improving emissions) that resulted in additional deterioration of air heater baskets. Air compressors have been replaced on Brown Unit 3, Mill Creek Units 3 and 4, and Green River Units 3 and 4. The new air compressors run at greater efficiency and lower dew points, reducing the number of instrument or control-related unit derates. Condensers and heat exchangers across the fleet have shown signs of deterioration due to age and to zebra muscles. These issues have created unit derates from tube overheating or poor boiler chemistry (due to tube leaks). A number of the condensers or heat exchangers have been retubed; additionally, an Eddy Current testing program is performed on the tubes to reduce the number of forced derates. Sections of the boiler inlet and outlet ductwork have been replaced on Brown Units 1 and 3, Green River Unit 4, Mill Creek units, and Cane Run units. The ductwork was replaced due to age and corrosion which had caused boiler performance issues and pluggage in the unit scrubber modules.

During the turbine/generator outages, testing has indicated a number of stator cooling leak issues or generator/exciter winding insulation deterioration issues that have resulted in scheduled outage rewinds or repairs. These rewinds or repairs have occurred at Brown Units 2 and 3, Mill Creek Units 2 and 4, and Ghent Unit 1.

Additionally, there have been several environmentally related projects which have helped maintain the integrity and accuracy of data. Several continuous emission mercury monitor probes were tested at Trimble County Unit 1 during 2006 and 2007. Mercury monitor instruments ("Appendix K" type) were selected and will be installed across the fleet in 2008. SO_2, NO_X and CO_2 instrument replacements were completed in 2003 for units across the fleet. New pH monitoring controls were replaced on Trimble County Unit 1 which resulted in improved flue gas desulphurization (FGD) efficiency. New FGD installation projects are under construction at Brown and Ghent stations. By reducing the amount of SO_2 emissions, the new FGD installations reduce the Companies' risk associated with SO_2 emission allowance prices.

The hydroelectric fleet units at Dix Dam and Ohio Falls Stations are under going major upgrades. The units at Ohio Falls Station are under a complete renovation upgrade that includes new water flow gates (wicket gates), new impellers, generator rewinds and new unit controls and instrumentation. The rehabilitation project will increase each unit's rated capacity from 10 MW to 12.582 MW, and increases the operating run times. A further description of this project follows in the next subsection titled "Rehabilitation of Ohio Falls." The units at Dix Dam had the inlet valves (Johnson valves) replaced due to probability of complete failure of this vintage valve. Dix Dam Unit 2 had the wicket gates replaced and the unit was overhauled. All work at Dix Dam improves the availability of these units.

Rehabilitation of Ohio Falls

The Ohio Falls Station was granted a 40-year operational license by the Federal Energy Regulatory Commission (FERC) effective October 25, 2005. The license indicates that the Companies would complete the upgrades to 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 8 is scheduled to begin in 2008.

The Companies continually evaluate resources available to meet load obligations, including the options at the Ohio Falls Station. The remaining five units will undergo investment review prior to rehabilitation taking place. Total rehabilitation of all eight units will result in increasing the expected capacity output of the Ohio Falls Station to 64 MW from the 48 MW capacity output prior to performing the rehabilitation. Moreover, the rehabilitation should provide potentially an increase of 187 GWh to annual energy production.

Transmission

The primary purpose of the Companies' (KU and LG&E) 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' (KU and LG&E) 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 10-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 2004 to 2006, LG&E and KU have had projects to install, upgrade or replace an average of 14 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 17 such projects were completed in 2007. This trend is expected to continue and 26 distribution substations have already been targeted for review in 2008 and 2009 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. 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 this practice as studies identify where power factor correction would most benefit the system, taking into account the cost of installation and the resulting savings in capacity and energy. Over the past three years, LG&E and KU have installed in excess of $2.5 million in capacitors for power factor improvement.

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

The IRP for the Companies includes 12 new demand-side management (DSM) programs as options for meeting future customer demand. Eleven of the potential programs are designed to improve energy efficiency. One of the potential programs is a full scale offering of our current Smart Metering/Residential Responsive Pricing pilot program.

As with many DSM programs, uncertainties surround the implementation of the programs. Additional detail on DSM alternatives considered for inclusion in the plan is contained in the report titled *Screening of Demand-Side Management (DSM) Options* contained in Volume III, Technical Appendix.

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* (April 2008) contained in Volume III, Technical Appendix.

LG&E owns a 75 percent undivided interest in Trimble County Unit 1. Of the remaining 25 percent of the unit, 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, IMEA and IMPA, 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 jointly own Trimble County Unit 2 with IMPA and IMEA. 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

2007 $

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 - Peaking Capacity	Gas	35	[redacted]	$23	$28	9,624	Yes	Mature
Simple Cycle GE 7EA CT - Peaking Capacity	Gas	76	[redacted]	$16	$26	12.041	Yes	Mature
Simple Cycle GE 7FA CT - Peaking Capacity	Gas	155	[redacted]	$12	$24	10.815	Yes	Mature
Combined Cycle GE 7EA CT - Intermediate Load	Gas	114	[redacted]	$32	$5	8.264	Yes	Mature
Combined Cycle GE 7FA CT - Intermediate Load	Gas	238	[redacted]	$20	$5	7.222	Yes	Mature
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	Gas	475	[redacted]	$18	$4	7.214	Yes	Mature
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	Gas	817	[redacted]	$14	$4	7.161	Yes	Commercial
Siemens 5000F CC CT - Intermediate Load	Gas	267	[redacted]	$15	$5	7,257	Yes	Mature
Humid Air Turbine Cycle CT - 366 MW	Gas	364	[redacted]	$8	$5	10,382	No	Developmental
Kalina Cycle CC CT - 282 MW	Gas	260	[redacted]	$16	$2	6.373	No	Developmental
Cheng Cycle CT - 140 MW	Gas	127	[redacted]	$15	$5	7.437	No	Developmental
Peaking Microturbine - 0.03 MW	Gas	0 03	[redacted]	$148	$32	14.561	Yes	Commercial
Baseload Microturbine - 0 03 MW	Gas	0 03	[redacted]	$148	$6	14.561	Yes	Commercial
Pulverized Coal								
Subcritical Pulverized Coal - 250 MW	Coal	250	[redacted]	$55	$3	9 260	Yes	Mature
Subcritical Pulverized Coal - 500 MW	Coal	500	[redacted]	$42	$3	9 218	Yes	Mature
Subcritical Pulverized Coal, High Sulfur - 500 MW	Coal	500	[redacted]	$46	$3	9 145	Yes	Mature
Circulating Fluidized Bed - 250 MW	Coal	250	[redacted]	$49	$2	9.384	Yes	Mature
Circulating Fluidized Bed - 500 MW	Coal	500	[redacted]	$40	$2	9.348	Yes	Mature
Supercritical Pulverized Coal - 500 MW	Coal	500	[redacted]	$46	$2	8,920	Yes	Mature
Supercritical Pulverized Coal, High Sulfur - 500 MW	Coal	500	[redacted]	$46	$3	8.852	Yes	Mature
Supercritical Pulverized Coal - 750 MW	Coal	739	[redacted]	$35	$2	8.928	Yes	Mature
Supercritical Pulverized Coal, High Sulfur - 750 MW	Coal	739	[redacted]	$35	$3	8.858	Yes	Mature
Pressurized Fluid. Bed Combust. Coal								
Pressurized Fluidized Bed Combustion	Coal	248	[redacted]	$80	$3	10.396	No	Developmental
Integrated Gasification Combined Cycle								
1x1 IGCC	Coal Gasification	289	[redacted]	$55	$3	8.448	Yes	Commercial
2x1 IGCC	Coal Gasification	580	[redacted]	$44	$3	8.412	Yes	Commercial
2x1 IGCC, High Sulfur	Coal Gasification	584	[redacted]	$43	$3	8.391	Yes	Commercial
Coal Technologies with Carbon Capture & Sequestration								
Subcritical Pulverized Coal - 500 MW - CCS	Coal	501	[redacted]	$51	$5	12.808	No	Developmental
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	Coal	500	[redacted]	$55	$5	12.570	No	Developmental
Circulating Fluidized Bed - 500 MW - CCS	Coal	500	[redacted]	$49	$4	12.940	No	Developmental
Supercritical Pulverized Coal - 500 MW - CCS	Coal	500	[redacted]	$55	$4	12.258	No	Developmental
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	Coal	500	[redacted]	$55	$5	12.080	No	Developmental
Supercritical Pulverized Coal - 750 MW - CCS	Coal	739	[redacted]	$43	$4	12.198	No	Developmental
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	Coal	739	[redacted]	$43	$5	12.018	No	Developmental
1x1 IGCC - CCS	Coal Gasification	261	[redacted]	$67	$3	10.110	No	Developmental
2x1 IGCC - CCS	Coal Gasification	516	[redacted]	$54	$3	10.099	No	Developmental
2x1 IGCC, High Sulfur - CCS	Coal Gasification	522	[redacted]	$54	$3	10.076	No	Developmental
Energy Storage								
Pumped Hydro Energy Storage - 500 MW	Charging Only	500	[redacted]	$12	$35	0	Yes	Mature
Lead-Acid Battery Energy Storage - 5 MW	Charging Only	5	[redacted]	$19	$32	0	Yes	Mature
Compressed Air Energy Storage - 500 MW	Gas and Charging	500	[redacted]	$19	$24	4.600	Yes	Commercial
Renewable Energy								
Wind Energy Conversion - 50 MW	No Fuel	50	[redacted]	$48	$0	0	Yes	Commercial
Geothermal - 30 MW	Renew	30	[redacted]	$65	$6	0	Yes	Commercial
Solar Photovoltaic								
Solar Photovoltaic - 50 kW	No Fuel	0.1	[redacted]	$40	$0	0	Yes	Commercial
Solar Thermal								
Solar Thermal, Parabolic Trough - 100 MW	No Fuel	100	[redacted]	$67	$1	0	Yes	Commercial
Solar Thermal, Parabolic Dish - 1 2 MW	No Fuel	1.2	[redacted]	$60	$0	0	Yes	Commercial
Solar Thermal, Central Receiver - 50 MW	No Fuel	50	[redacted]	$120	$1	0	No	Commercial
Solar Thermal, Solar Chimney - 50 MW	No Fuel	50	[redacted]	$69	$0	0	No	Developmental
Waste Energy								
MSW Mass Burn - 7 MW	MSW	7	[redacted]	$568	$38	19.568	Yes	Commercial
RDF Stoker-Fired - 7 MW	RDF	7	[redacted]	$471	$12	16,936	Yes	Commercial
Landfill Gas IC Engine - 5 MW	Landfill Gas	5	[redacted]	$202	$0	9,898	Yes	Mature
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	10% TDF / 90% Coal	50	[redacted]	$97	$3	10,726	Yes	Mature
Sewage Sludge & Anaerobic Digestion - 085 MW	No Fuel	0.085	[redacted]	$215	$0	9 900	Yes	Commercial
Bio Mass								
Bio Mass (Co-Fire)	10% Renew / 90% Coal	500	[redacted]	$47	$2	8.980	Yes	Mature
Hydroelectric Power								
Hydroelectric - New - 30 MW	No Fuel	30	[redacted]	$39	$0	0	Yes	Mature
Ohio Falls 9-10	No Fuel	34	[redacted]	$10	$0	0	Yes	Mature
Other								
Spark Ignition Engine - 5 MW	Gas	5	[redacted]	$170	$0	9,492	Yes	Mature
Molten Carbonate Fuel Cell - 300 kW	Gas	0.3	[redacted]	$66	$5	8,059	Yes	Commercial

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 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 May 11, 2007, the Companies sent out a RFP for peaking power over the next few years to which three parties responded. Results of this RFP process provided the power purchases in the resource and acquisition plan associated with a peaking power contract with Dynegy from the Bluegrass facility in Oldham County, Ky., in the summers of 2008 and 2009.

Also, the Companies issued a RFP on July 9, 2007, to explore alternatives using renewable resources for power purchases. The results of the RFP are being explored for future value to the Customers and the Companies. Further details of this RFP process have been covered under the subsection *Renewable Energy* of Section 6 of this IRP.

The Companies also consider short-term economy purchases on a non-firm basis. Further details of this are covered under the subsection 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' (KU and LG&E) 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)

Kentucky Utilities Company / Louisville Gas and Electric Company

Existing and Planned Electric Generating Facilities

1 Plant Name	2 Unit No.	3 Location in Kentucky	4 Status	5 Operation Date	6 Facility Type	7 Net Capability (MW) Winter	 Summer	8 Entitlement KU	 LGE	9 Fuel Type	10 Fuel Storage Cap/SO2 Content	11 Scheduled Upgrades Derates, Retirements
Cane Run	4	Louisville	Existing	1962	Steam	155	155		100%	Coal (Rail)	250.000 Tons (6 0# SO2)	None
	5			1966		168	168					
	6			1969		240	240					
	11			1968	Turbine	14	14			Gas/Oil	100,000 Gals	
Dix Dam	1-3	Burgin	Existing	1925	Hydro	24	24	100%		Water	None	None
E. W Brown Coal	1	Burgin	Existing	1957	Steam	102	101	100%		Coal (Rail)	360.000 Tons (~2.2# SO2)	FGD Derate - 2009
	2			1963		169	167					
	3			1971		433	429					
E.W. Brown-ABB 11N2	5			2001	Turbine	143	139	47%	53%	Gas	2 200.000 Gals	None
E.W Brown-ABB GT24	6			1999		168	154	62%	38%	Gas/Oil		None
	7			1999		168	154					
E.W Brown-ABB 11N2	8			1995		140	125	100%				None
	9			1994		140	125					
	10			1995		140	125					
	11			1996		140	125					
Ghent	1	Ghent	Existing	1974	Steam	468	475	100%		Coal (Barge)	310,000 Tons (6# SO2)	None
	2			1977		466	484				1.000.000 Tons (1 1# SO2 & PRB)	FGD Derate - 2008
	3			1981		482	480					None
	4			1984		495	493					FGD Derate - 2009
Green River	3	Central City	Existing	1954	Steam	71	68	100%		Coal	170,000 Tons	None
	4			1959		102	95					
Haefling	1	Lexington	Existing	1970	Turbine	14	12	100%		Gas/Oil	630.000 Gals	None
	2			1970		14	12					
	3			1970		14	12					
Mill Creek	1	Louisville	Existing	1972	Steam	303	303		100%	Coal (Barge & Rail)	750.000 Tons	None
	2			1974		299	301					
	3			1978		397	391					
	4			1982		492	477					
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	Run of River Plant (34/52)			100%	Water	None	Rehab began Fall 2005
Paddy's Run	11	Louisville	Existing	1968	Turbine	13	12		100%	Gas	None	None
	12			1968		28	23					
Paddys Run-Siem/West V84.3a	13			2001		175	158	47%	53%			
Tyrone	3	Versailles	Existing	1953	Steam	73	71			Coal (Trk)	30,000 Tons (1.4# SO2)	None
Trimble County Coal (75%)	1	Near Bedford	Existing	1990	Steam	515 (386)	511 (383)	0%	75%	Coal (Barge)	500,000 Tons (6.0# SO2)	None
Trimble County-GE7FA	5			2002	Turbine	180	160	71%	29%	Gas		
	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												
Trimble County Coal (75%)	2	Near Bedford	Construction	2010	Steam	750 (563)	732 (549)	61%	14%	Coal	800,000 Tons (5.5# SO2)	None
Greenfield Combined Cycle	1	Unknown	Proposed	2015	Turbine	551	475	Unknown		Gas	None	None
	2			2019		551	475					
Greenfield CT	1	Unknown	Proposed	2022	Turbine	184	155	Unknown		Gas	None	None

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 1

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	55.8	25.4	41.7	37.7	33.4	34.1	34.4	35.0	31.5	31.1	35.4	35.3	41.8	39.6	39.3	45.2
	Availability Factor (%)	77.6	89.0	83.6	89.0	89.0	89.0	89.0	80.0	89.0	89.0	89.0	89.0	89.0	89.0	80.0	89.0
b	Average Heat Rate (Btu/kWh)	11,173	11,210	10,562	11,241	11,394	11,038	11,040	11,036	11,062	11,058	11,053	11,051	11,031	11,044	11,042	11,030
c	Cost of Fuel ($/MBTU)	2.43	[redacted]														

Notes: 2007 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 2

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	69.3	39.3	38.0	35.8	36.5	36.9	37.1	40.4	39.4	34.2	44.0	44.0	50.6	46.8	50.8	54.1
	Availability Factor (%)	91.9	89.0	80.0	89.0	89.0	89.0	89.0	89.0	89.0	80.0	89.0	89.0	89.0	89.0	89.0	89.0
b	Average Heat Rate (Btu/kWh)	10,361	10,107	10,166	10,413	10,437	10,399	10,409	10,384	10,401	10,414	10,384	10,381	10,361	10,363	10,357	10,355
c	Cost of Fuel ($/MBTU)	2.36	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	63.8	50.6	52.7	55.3	52.8	46.6	52.9	55.0	62.5	61.3	64.7	63.5	59.1	65.5	68.9	69.6
	Availability Factor (%)	85.0	79.4	79.4	88.4	88.4	79.4	88.4	88.4	88.4	88.4	88.4	88.4	79.4	88.4	88.4	88.4
b	Average Heat Rate (Btu/kWh)	10,289	10,849	10,746	11,028	11,055	11,026	11,018	10,998	10,981	10,948	10,926	10,942	10,929	10,919	10,898	10,895
c	Cost of Fuel ($/MBTU)	2.37	[redacted]														

Notes: 2007 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 5

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	1.9	1.7	2.9	1.1	1.0	1.2	1.1	1.4	0.5	0.6	0.8	1.0	0.5	0.5	0.7	1.0
	Availability Factor (%)	94.1	90.3	86.8	90.3	76.4	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	**Average Heat Rate (Btu/kWh)**	16,676	13,359	13,043	12,774	12,360	12,301	12,237	12,234	12,299	12,259	12,252	12,220	12,291	12,251	12,230	12,205
c	**Cost of Fuel ($/MBTU)**	7.50	[redacted]														

Notes: 2007 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 6

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	6.6	8.4	11.8	6.8	5.2	5.1	4.5	6.2	2.7	2.0	2.9	3.2	3.1	2.0	2.6	3.4
	Availability Factor (%)	77.0	86.8	86.8	72.9	83.4	86.8	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	Average Heat Rate (Btu/kWh)	11,813	10,302	10,304	10,302	10,304	10,298	10,294	10,292	10,291	10,298	10,298	10,300	10,290	10,296	10,297	10,297
c	Cost of Fuel ($/MBTU)	8.01	[redacted]														

Notes: 2007 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 7

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	3.8	8.4	14.8	8.6	6.0	6.6	5.7	7.5	4.4	3.4	4.3	4.3	3.9	2.5	3.2	4.2
	Availability Factor (%)	83.9	76.4	83.4	86.8	76.4	86.8	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	**Average Heat Rate (Btu/kWh)**	12,062	10,284	10,287	10,285	10,288	10,287	10,285	10,283	10,278	10,282	10,284	10,288	10,280	10,286	10,286	10,287
c	**Cost of Fuel ($/MBTU)**	8.25	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	2.1	1.3	2.2	0.7	0.7	0.8	0.8	1.0	0.3	0.4	0.5	0.7	0.3	0.4	0.5	0.7
	Availability Factor (%)	98.9	86.8	90.3	86.8	86.8	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	**Average Heat Rate (Btu/kWh)**	15,186	12,731	12,639	12,459	12,344	12,305	12,280	12,279	12,309	12,291	12,286	12,275	12,308	12,288	12,279	12,270
c	**Cost of Fuel ($/MBTU)**	7.74	[redacted]														

Notes: 2007 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

E.W. Brown 9

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	1.2	1.0	1.6	0.5	0.5	0.6	0.6	0.7	0.2	0.2	0.4	0.5	0.2	0.2	0.3	0.5
	Availability Factor (%)	99.2	90.3	76.4	90.3	86.8	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	**Average Heat Rate (Btu/kWh)**	15,911	12,558	12,452	12,410	12,327	12,300	12,289	12,285	12,316	12,304	12,297	12,286	12,325	12,300	12,290	12,278
c	**Cost of Fuel ($/MBTU)**	7.44	[redacted]														

Notes: 2007 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 10

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	0.6	0.8	1.2	0.3	0.3	0.4	0.4	0.5	0.1	0.2	0.2	0.3	0.1	0.2	0.2	0.4
	Availability Factor (%)	98.3	90.3	76.4	90.3	90.3	86.8	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	**Average Heat Rate (Btu/kWh)**	22,111	12,434	12,378	12,373	12,329	12,307	12,300	12,298	12,341	12,322	12,312	12,297	12,322	12,312	12,300	12,287
c	**Cost of Fuel ($/MBTU)**	7.77	[redacted]														

Notes: 2007 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

E.W. Brown 11

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	0.5	0.5	0.8	0.2	0.2	0.2	0.2	0.3	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.2
a	**Availability Factor (%)**	97.4	90.3	86.8	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	**Average Heat Rate (Btu/kWh)**	16,123	12,366	12,358	12,364	12,337	12,315	12,316	12,311	12,327	12,336	12,312	12,315	12,330	12,325	12,303	12,302
c	**Cost of Fuel ($/MBTU)**	7.40	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	81.4	56.3	52.4	45.3	33.9	38.3	38.4	42.5	34.4	34.7	38.8	34.1	44.4	41.6	44.9	46.4
	Availability Factor (%)	93.6	86.6	86.9	87.2	78.6	87.5	87.5	87.5	87.5	87.5	87.5	78.6	87.5	87.5	87.5	87.5
b	Average Heat Rate (Btu/kWh)	10,610	10,193	10,305	10,309	10,336	10,333	10,331	10,325	10,340	10,337	10,334	10,335	10,326	10,329	10,324	10,325
c	Cost of Fuel ($/MBTU)	1.62	[redacted]														

Notes: 2007 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 5

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	70.9	44.4	39.6	32.2	30.1	29.9	31.0	32.8	23.0	24.2	30.2	30.5	33.4	32.5	36.1	32.3
	Availability Factor (%)	84.7	78.8	87.7	87.7	87.7	87.7	87.7	87.7	78.8	87.7	87.7	87.7	87.7	87.7	87.7	78.8
b	Average Heat Rate (Btu/kWh)	10,932	10,779	10,429	10,360	10,379	10,386	10,403	10,439	10,372	10,398	10,392	10,393	10,376	10,397	10,397	10,435
c	Cost of Fuel ($/MBTU)	1.62	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	66.4	54.1	48.6	50.9	44.4	44.9	44.3	47.3	44.0	39.0	47.8	46.5	52.2	49.0	52.2	55.5
	Availability Factor (%)	76.7	86.7	78.1	87.3	87.6	87.6	87.6	87.6	87.6	78.6	87.6	87.6	87.6	87.6	87.6	87.6
b	Average Heat Rate (Btu/kWh)	10,353	10,472	10,337	10,327	10,334	10,333	10,335	10,332	10,331	10,338	10,326	10,332	10,324	10,328	10,327	10,324
c	Cost of Fuel ($/MBTU)	1.62	[redacted]														

Notes: 2007 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 11

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.1
	Availability Factor (%)	74.5	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)	32,750	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)	8.09	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	70.1	87.8	77.1	87.8	86.0	88.0	88.0	78.8	88.0	87.9	88.0	88.0	88.0	88.0	78.9	88.0
	Availability Factor (%)	72.6	90.9	83.6	89.1	87.3	89.1	89.1	80.0	89.1	89.1	89.1	89.1	89.1	89.1	80.0	89.1
b	Average Heat Rate (Btu/kWh)	10,690	10,647	10,365	10,555	10,403	10,401	10,403	10,409	10,403	10,402	10,403	10,403	10,402	10,403	10,410	10,403
c	Cost of Fuel (\$/MBTU)	1.56	[redacted]														

Notes: 2007 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 2

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	81.5	55.7	72.0	81.3	80.3	71.4	81.6	83.0	85.1	85.3	85.2	85.1	76.6	85.1	85.9	86.0
	Availability Factor (%)	90.7	87.3	80.0	80.0	89.1	78.2	89.1	89.1	89.1	89.1	89.1	89.1	80.0	89.1	89.1	89.1
b	**Average Heat Rate (Btu/kWh)**	10,134	10,556	10,107	10,364	10,380	10,312	10,300	10,298	9,971	10,441	10,442	10,444	10,445	10,443	10,437	10,437
c	**Cost of Fuel ($/MBTU)**	2.47	[redacted]														

Notes: 2007 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

Ghent 3

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	56.1	84.1	84.7	65.2	75.6	83.0	81.3	83.5	83.2	83.0	75.8	84.8	85.2	84.8	86.2	86.2
	Availability Factor (%)	63.5	89.1	89.1	78.2	89.1	89.1	89.1	89.1	89.1	89.1	80.0	89.1	89.1	89.1	89.1	89.1
b	Average Heat Rate (Btu/kWh)	11,070	10,810	10,821	11,194	10,241	10,269	10,248	10,258	10,257	10,257	10,311	10,278	10,280	10,279	10,282	10,269
c	Cost of Fuel ($/MBTU)	1.84	[redacted]														

Notes: 2007 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

Ghent 4

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	74.9	76.7	86.5	85.7	87.0	87.4	87.3	87.3	79.0	88.2	88.1	88.0	88.0	87.9	88.2	79.4
	Availability Factor (%)	92.8	78.4	89.3	87.5	89.3	89.3	89.3	89.3	80.2	89.3	89.3	89.3	89.3	89.3	89.3	80.2
b	**Average Heat Rate (Btu/kWh)**	10,713	10,169	10,418	10,453	10,466	10,462	10,466	10,466	10,469	10,468	10,462	10,467	10,463	10,459	10,460	10,469
c	**Cost of Fuel ($/MBTU)**	2.49	[redacted]														

Notes: 2007 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

Green River 3

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	70.6	18.8	24.0	20.7	16.1	17.8	16.4	21.1	18.8	15.9	20.3	20.6	21.9	18.1	20.9	22.9
	Availability Factor (%)	94.8	85.9	77.2	85.9	85.9	85.9	85.9	85.9	85.9	77.2	85.9	85.9	85.9	85.9	85.9	85.9
b	Average Heat Rate (Btu/kWh)	12,481	13,056	13,131	13,096	13,155	13,173	13,191	13,138	13,122	13,083	13,107	13,065	12,997	12,977	12,971	12,928
c	Cost of Fuel ($/MBTU)	1.85	[redacted]														

Notes: 2007 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

Green River 4

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	69.2	34.1	32.8	28.8	23.8	21.2	23.7	26.6	27.4	26.5	31.2	31.3	29.7	28.7	31.5	32.0
	Availability Factor (%)	86.8	85.9	85.9	85.9	85.9	77.2	85.9	85.9	85.9	85.9	85.9	85.9	77.2	85.9	85.9	85.9
b	**Average Heat Rate (Btu/kWh)**	11,096	11,189	11,356	11,153	11,106	11,090	11,101	11,092	11,099	11,096	11,095	11,084	11,091	11,091	11,088	11,097
c	**Cost of Fuel ($/MBTU)**	1.88	[redacted]														

Notes: 2007 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

Haefling 1,2,3

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	0.0	0.2	0.3	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
	Availability Factor (%)	92.8	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)	-31,092	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021
c	Cost of Fuel ($/MBTU)	9.11	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	81.5	80.9	82.6	70.1	79.3	72.1	77.8	71.3	73.4	68.8	75.9	63.3	76.8	72.7	79.6	75.8
	Availability Factor (%)	92.2	86.2	91.6	79.0	91.6	86.2	91.6	86.2	91.6	86.2	91.6	79.0	91.6	86.2	91.6	86.2
b	**Average Heat Rate (Btu/kWh)**	10,445	10,042	10,083	10,089	10,072	10,083	10,075	10,089	10,078	10,081	10,079	10,097	10,085	10,090	10,082	10,090
c	**Cost of Fuel ($/MBTU)**	1.62	[redacted]														

Notes: 2007 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 2

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	73.8	75.5	71.7	65.4	59.4	61.0	58.0	64.8	59.9	60.7	54.8	65.8	67.6	67.8	66.6	71.8
	Availability Factor (%)	85.7	90.8	83.9	84.2	86.2	91.6	86.2	91.6	86.2	91.6	79.0	91.6	86.2	91.6	86.2	91.6
b	Average Heat Rate (Btu/kWh)	10,647	10,252	10,224	10,220	10,221	10,236	10,235	10,224	10,232	10,233	10,242	10,226	10,221	10,226	10,222	10,225
c	Cost of Fuel ($/MBTU)	1.62	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	81.9	85.9	76.6	81.1	64.4	75.3	70.6	77.2	71.8	75.5	73.8	78.0	68.6	79.0	76.2	83.3
	Availability Factor (%)	86.9	90.4	85.4	91.2	79.0	91.5	86.2	91.5	86.2	91.5	86.2	91.5	79.0	91.5	86.2	91.5
b	**Average Heat Rate (Btu/kWh)**	10,584	10,158	10,418	10,237	10,404	10,388	10,396	10,375	10,386	10,388	10,371	10,369	10,373	10,365	10,357	10,333
c	**Cost of Fuel ($/MBTU)**	1.63	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Capacity Factor (%)	85.8	80.1	81.7	82.0	86.9	79.2	83.6	71.2	83.6	77.7	85.1	79.3	85.5	79.6	85.8	74.3
a	Availability Factor (%)	90.8	85.4	91.1	86.0	91.6	86.2	91.6	79.0	91.6	86.2	91.6	86.2	91.6	86.2	91.6	79.0
b	Average Heat Rate (Btu/kWh)	10,711	10,527	10,772	10,554	10,626	10,638	10,634	10,642	10,634	10,641	10,631	10,638	10,630	10,637	10,629	10,640
c	Cost of Fuel ($/MBTU)	1.63	[redacted]														

Notes: 2007 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

Paddy's Run 11

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	0.1	0.1	0.2	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.1
	Availability Factor (%)	97.4	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)	74,617	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)	6.51	[redacted]														

Notes: 2007 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

Paddy's Run 12

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	-0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0
	Availability Factor (%)	22.1	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)	0	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)	6.51	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	4.8	11.7	13.2	5.9	5.5	6.6	5.1	6.4	5.0	3.7	4.8	4.6	3.8	3.3	3.8	5.0
	Availability Factor (%)	90.9	88.6	88.6	88.6	88.6	88.6	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	**Average Heat Rate (Btu/kWh)**	10,678	10,163	10,125	10,043	9,958	9,874	9,877	9,859	9,864	9,865	9,863	9,858	9,865	9,862	9,862	9,858
c	**Cost of Fuel ($/MBTU)**	7.51	[redacted]														

Notes: 2007 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 1 (75%)

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	80.4	94.8	79.7	94.4	86.6	94.4	86.6	94.4	86.5	94.4	79.3	94.3	86.6	94.3	86.7	94.6
	Availability Factor (%)	83.7	95.0	80.4	95.0	87.7	95.0	87.7	95.0	87.7	95.0	80.4	95.0	87.7	95.0	87.7	95.0
b	**Average Heat Rate (Btu/kWh)**	10,200	10,706	10,408	11,026	10,579	10,566	10,557	10,567	10,557	10,566	10,547	10,567	10,559	10,566	10,572	10,566
c	**Cost of Fuel ($/MBTU)**	1.55	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	6.6	16.5	23.6	12.2	12.5	13.7	13.6	15.7	12.0	9.6	12.5	12.1	10.5	7.9	9.1	10.1
	Availability Factor (%)	76.1	90.3	90.3	67.7	69.5	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	Average Heat Rate (Btu/kWh)	11,430	11,111	11,037	10,755	10,480	10,444	10,313	10,266	10,308	10,220	10,218	10,193	10,250	10,164	10,180	10,191
c	Cost of Fuel ($/MBTU)	7.34	[redacted]														

Notes: 2007 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 6

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	8.0	11.6	18.9	14.2	9.0	9.7	11.0	12.5	9.1	7.7	9.9	9.9	8.2	6.5	7.5	8.4
	Availability Factor (%)	93.8	69.5	90.3	90.3	67.7	69.5	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	Average Heat Rate (Btu/kWh)	11,698	10,999	11,144	11,032	10,400	10,358	10,342	10,257	10,309	10,211	10,218	10,181	10,258	10,162	10,171	10,175
c	Cost of Fuel ($/MBTU)	7.50	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	6.0	9.3	11.2	10.7	9.5	8.4	8.6	9.8	6.8	6.1	7.8	8.0	6.2	5.2	6.1	6.9
	Availability Factor (%)	98.3	69.5	90.3	90.3	90.3	67.7	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	Average Heat Rate (Btu/kWh)	11,216	11,007	11,123	11,096	10,638	10,370	10,316	10,247	10,310	10,209	10,220	10,173	10,268	10,167	10,169	10,166
c	Cost of Fuel ($/MBTU)	7.48	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	9.5	8.8	9.1	7.8	7.2	7.3	6.8	7.6	5.0	4.7	6.0	6.4	4.6	4.1	4.8	5.6
	Availability Factor (%)	98.3	90.3	69.5	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	Average Heat Rate (Btu/kWh)	11,553	11,295	11,204	11,171	10,654	10,445	10,294	10,242	10,313	10,216	10,224	10,173	10,279	10,178	10,173	10,164
c	Cost of Fuel ($/MBTU)	7.61	[redacted]														

Notes: 2007 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 9

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	9.4	6.5	9.3	5.5	5.3	5.4	5.2	5.9	3.6	3.6	4.6	5.0	3.3	3.2	3.8	4.4
	Availability Factor (%)	98.8	90.3	69.5	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	**Average Heat Rate (Btu/kWh)**	11,530	11,441	11,192	11,243	10,621	10,424	10,283	10,243	10,317	10,224	10,231	10,180	10,288	10,191	10,182	10,167
c	**Cost of Fuel ($/MBTU)**	7.62	[redacted]														

Notes: 2007 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

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Capacity Factor (%)	8.3	4.8	8.2	3.6	3.7	4.0	3.9	4.4	2.5	2.6	3.4	3.9	2.4	2.4	2.9	3.5
a	**Availability Factor (%)**	98.7	90.3	90.3	69.5	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
b	**Average Heat Rate (Btu/kWh)**	11,537	11,398	11,586	11,178	10,610	10,423	10,284	10,247	10,322	10,236	10,243	10,192	10,295	10,208	10,191	10,175
c	**Cost of Fuel ($/MBTU)**	7.60	[redacted]														

Notes: 2007 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

Tyrone 3

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	62.7	18.4	25.3	19.1	18.8	18.2	17.9	19.5	20.8	20.3	22.2	22.1	24.3	22.7	25.9	27.6
	Availability Factor (%)	86.1	84.1	84.5	76.2	85.2	85.2	85.2	85.2	85.2	85.2	76.5	85.2	85.2	85.2	85.2	85.2
b	**Average Heat Rate (Btu/kWh)**	12,974	13,039	12,337	12,332	12,328	12,337	12,327	12,320	12,272	12,258	12,230	12,246	12,205	12,232	12,222	12,210
c	**Cost of Fuel ($/MBTU)**	2.97	[redacted]														

Notes: 2007 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

Zorn 1

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
	Availability Factor (%)	95.5	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)	22,878	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)	6.73	[redacted]														

Notes: 2007 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

Trimble County 2 (75%)

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)				47.0	89.7	94.2	94.2	94.2	94.2	94.2	94.2	94.2	94.2	94.2	94.2	94.2
	Availability Factor (%)				85.8	89.4	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0
b	Average Heat Rate (Btu/kWh)				8,865	8,865	8,865	8,865	8,865	8,865	8,865	8,865	8,865	8,865	8,865	8,865	8,865
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 2007 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

Combined Cycle 1

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**									15.1	19.2	24.1	22.6	24.2	18.7	22.8	25.4
	Availability Factor (%)									91.7	91.7	91.7	91.7	91.7	91.7	91.7	91.7
b	**Average Heat Rate (Btu/kWh)**									6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 2007 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

Combined Cycle 2

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)													14.9	21.5	25.9	28.6
	Availability Factor (%)													91.7	91.7	91.7	91.7
b	Average Heat Rate (Btu/kWh)													6,953	6,953	6,953	6,953
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 2007 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

Greenfield CT 1

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	Capacity Factor (%)																0.2
	Availability Factor (%)																93.9
b	Average Heat Rate (Btu/kWh)																10,815
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 2007 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

Dix Dam 1,2,3

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	16.7	28.7	28.8	28.8	28.8	28.7	28.8	28.8	28.8	28.7	28.8	28.8	28.8	28.7	28.8	28.8
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: 2007 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

Ohio Falls 1-8

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
a	**Capacity Factor (%)**	31.0	65.1	68.4	71.5	73.9	75.8	77.4	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
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: 2007 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 2007 Dollars)

	Supercritical Coal	3x1 Combined Cycle	2x1 Combined Cycle	2x1 IGCC	Wind Turbine	Simple Cycle CT	Ohio Falls Unit
Capital Costs ($/kW)	[redacted]						
Total Capital Costs ($x1000)							
Capital Escalation Factor (%)	1.9	2.2	2.2	1.9	2.2	2.2	2.2
Variable O&M Escalation Factor (%)	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Fixed O&M Escalation Factor (%)	1.6	1.6	1.6	1.6	1.6	1.6	1.6

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)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Existing units*	202,637	[redacted]														
Combined Cycle 1		[redacted]														
Combined Cycle 2		[redacted]														
Greenfield CT 1		[redacted]														

* Data not available by individual units

Notes: 2007 numbers are actuals.

An annual gas reservation expense is in included in the Fixed O&M of CTs and Combined Cycle units.

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

Kentucky Utilities Company / Louisville Gas & Electric Company

Total Electricity Production Costs (cents/kWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Existing units*	2.79	[redacted]														
Combined Cycle 1		[redacted]														
Combined Cycle 2		[redacted]														
Greenfield CT 1		[redacted]														

* Data not available by individual units

Notes: 2007 numbers are actuals.

Total Electric Production Costs includes Fixed O&M, Variable O&M, Fuel and Gas Transportation reservation.

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

Kentucky Utilities Company / Louisville Gas & Electric Company

Average Variable Production Costs (cents/kWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Existing units*	2.29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle 2		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Greenfield CT 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Data not available by individual units

Notes: 2007 numbers are actuals.

Average Variable Production Costs includes Variable O&M and Fuel.

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)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OMU	1,289	1,599	1,878	763	0	0	0	0	0	0	0	0	0	0	0	0
OVEC	1,200	1,458	1,454	1,454	1,454	1,458	1,454	1,454	1,454	1,458	1,454	1,454	1,454	1,458	1,454	1,454
Other	371	3	5	1	1	2	2	2	0	1	1	2	0	1	1	1

Sales (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OMU	53	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OTHER	1,618	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Notes: 2007 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

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
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

Notes: 2007 numbers are actuals.

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;

The following section contains a brief description of all existing, proposed and planned programs to reduce demand and energy usage. Existing programs include various rate schedules such as time of day rates, load reduction incentives and net metering as well as existing DSM programs that have been in place for several years, and two new pilot programs. Proposed programs include enhancements to existing DSM programs plus the addition of several new DSM programs as proposed in Case No. 2007-00319, which was recently approved by the Commission. New Programs consist of programs successfully passing the DSM screening process as described in *Screening of Demand-Side Management (DSM) Options* (March 2008) contained in Volume III, Technical Appendix.

Existing Programs

KU and LG&E Rate Schedule CSR1, CSR2, and CSR3 (Curtailable Service Riders) – This program is aimed at decreasing demand in the commercial and industrial sectors during system peak periods. In return for a rate incentive, participating customers agree to reduce demand to a predetermined level upon the respective Company's request.

KU Rate Schedules LCI-TOD & LMP-TOD and LI-TOD (Time-of-Day Rates) – This program is targeted at the commercial and industrial sectors. A differential in on- and off-peak demand charges is used to encourage large customers to shift part of their demand from system peak periods to off-peak periods.

LG&E Rate Schedule LC-TOD, LP-TOD, and LI-TOD (Time-of-Day Rates) – This program is targeted at the commercial and industrial sectors. A differential in on- and off-peak demand charges is used to encourage large customers to shift part of their demand from system peak periods to off-peak periods.

KU and LG&E Rate Schedule NMS (Net Metering Service) – This pilot program allows customers with a solar, wind, or hydro generation to offset their energy bill. The pilot program was initiated March 24, 2002, via Commission Order in Cases 2001-00304 and 2001-00303 for KU and LG&E, respectively. The Companies have since filed for the program to become a permanent rate in compliance with KRS 278.465 through KRS 278.468.

KU and LG&E Rate Schedule Load Reduction Incentive (LRI) – This program is aimed at decreasing demand during peak periods. Customers with standby generators of a minimum 500 kW receive a rate incentive by agreeing to carry that load upon the respective Company's request. The program was initiated as a three-year pilot program on August 1, 2000. KU and LG&E have since filed for and the Commission approved LRI as a permanent rider effective August 1, 2006.

KU and LG&E Rate Schedule Small Time-of-Day Service (STOD) – This pilot program is aimed at decreasing demand in small commercial classes. A differential in on- and off-peak energy charges is used to encourage customers to shift part of their demand from system peak periods to off-peak periods. The pilot program was initiated October 6, 2004, via Commission Order in Cases 2003-00434 and 2003-00433 for KU and LG&E respectively.

Residential Conservation 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.

Commercial Conservation 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.

Demand Conservation Program – This program cycles residential and commercial central air conditioning units, water heaters, and residential pool pumps of both KU and LG&E 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 those peak demand periods when the Companies need additional resources to meet customer demand.

WeCare Program – This program is designed to reduce the energy bills of customers that are less fortunate by weatherizing their homes. This program is available to "Low Income Home Energy Assistance Program" (LIHEAP) eligible customers.

Responsive Pricing Program - This pilot program consists of a responsive pricing rate structure using time of use (TOU) and real time, critical peak pricing components. The program uses a variable rate structure, namely a TOU rate structure with three different rates for different times during different days, and a real-time, critical peak price that will be in effect during times of particularly high demand. Customers would receive smart thermostats, energy use display devices, and water heater/pool pump controllers to automate energy use based on the price of electricity. This program is restricted to a maximum of 100 customers eligible for rate RS in any year and 50 customers eligible for rate GS in any year.

Commercial Real-Time Pricing - This pilot program is voluntary and offers large commercial and industrial customers the opportunity to modify their consumption patterns in order to manage their electric energy costs by increasing or decreasing load in response to hourly cost-based prices. The program is a three year pilot and will be available to customers in the fourth quarter of 2008.

Approved Programs (Case No. 2007-00319)

Residential Conservation Program – This program has been modified to include a new on-line energy audit tool, available at no cost to residential customers. The on-site audit portion has been enhanced, with an increased customer charge of $25.

Commercial Conservation Program – This program has been modified to include a significant rebate structure for cost-effective measures, most noticeably, high efficiency lighting retrofits and lighting fixtures.

Demand Conservation Program – This program will continue with no change.

WeCare Program – This program will continue with an increased effort to coordinate activities with implementing organizations of the federal weatherization program.

Residential High Efficiency Lighting – This program will provide residential customers with rebate coupons for compact fluorescent bulbs which can be used at participating retailers.

Energy Star New Homes – The objective of this program is to reduce residential energy usage and facilitate market transformation by creating a shift in builders' new home energy efficient construction practices. The Companies intend to utilize this program to educate builders, contractors and customers to increase awareness of environmental and financial benefits of whole-house energy efficient building practices. The Companies plan to partner with Homebuilders Associations within the state of Kentucky to adopt and implement the Department of Energy's ENERGY STAR® new homes energy efficiency program.

Residential and Commercial HVAC Diagnostics and Tune Up Program - The objective of this program is to reduce peak demand and energy use by performing a diagnostic check of the performance of residential and small commercial unitary air conditioning and heat pump units, concentrating on the most common causes, dirty, air restricted indoor and outdoor coils, and over and under refrigerant charge. Units that are determined to have these problems will be eligible for reduced rate on the corrective action through a HVAC company which is part of the authorized dealer network.

New Programs

Residential Window Films Program – Solar gain through windows is generally the largest contributor to residential cooling loads. This program would provide incentives for residential customers to install high performance film to existing windows to reduce solar heat gain, reducing cooling costs.

Residential Duct Evaluation and Sealing Program - Many residential air conditioners have duct systems that are poorly constructed and insulated, resulting in high rates of leakage. This program will perform diagnostic testing of residential duct systems and where potential savings are identified, will assist and provide incentives to customers for corrective action.

Residential Removal of Second Refrigerator Program - This program would provide incentives for residential customers to remove old, inefficient second refrigerators in the home. Multiple refrigerators are in place in approximately 25 percent of our customers' homes.

Commercial High Efficiency Heat Pump Program - This program would provide incentives for commercial customers currently serviced by electric resistive heating to convert and install a high efficiency heat pump system.

Commercial Duct Evaluation and Sealing Program - Many commercial air conditioners and heat pumps have duct systems that are poorly insulated and have high rates of leakage. This program will perform diagnostic testing of commercial duct systems and where potential savings are identified, will assist and provide incentives to customers for corrective action.

Commercial High Efficiency Motor Program - This program encourages commercial customers that are considering replacing worn out motors to purchase energy efficient motors by offering incentives.

Commercial Geothermal Heat Pump Program - This program would provide incentives for commercial customers building new facilities to install geothermal heat pump systems.

Commercial Energy Management Program - Commercial customers would be provided an incentive to install a system to monitor and control HVAC, lighting and equipment energy consumption, in order to reduce peak demand and usage.

Commercial Refrigeration Optimization Program - This program will provide incentives to commercial customers with refrigerators and freezers to improve the operational performance with improved controls, defrost cycles, and high efficiency fan motors.

Commercial Heat Pump Water Heater Program - Commercial restaurant and laundry customers, who have significant hot water usage, would be eligible to receive incentives to convert from electric resistance water heating to the more energy efficient heat pump water heater technology.

Commercial Refrigeration Case Cover Program - This program would provide incentives for commercial customers' to retrofit their refrigerator and freezer units with doors and case covers to reduce loss of cooled air, reducing energy demand and usage.

Responsive Pricing Program - This assumes the pilot program described earlier is successful resulting in a offering to residential customers. It consists of a responsive pricing rate structure using TOU and real-time, critical peak pricing components. The program uses a variable rate structure, namely a TOU rate structure with three different rates for different times during different days, and a real-time, critical peak price that will be in effect during times of particularly high demand. Customers would receive smart thermostats, energy use display devices, and water heater/pool pump controllers to automate energy use based on the price of electricity.

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

On March 31, 2008 the Commission issued an order in Case No. 2007-00319 approving the Companies application of the proposed Energy Efficiency Program Plan for the seven year period 2008-2014 and the proposed DSM cost recovery tariffs, with the exception of the proposed modification of the incentive mechanism. The Companies will proceed with the modification of the existing programs and the implementation of the new "proposed program" according to the Commission order. The Companies will continue to review and evaluate the proposed DSM programs contained in this IRP in future DSM filings.

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) below 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)

Kentucky Utilities Company/Louisville Gas and Electric Company
Demand Side Management Energy and Demand Impacts

Energy Reduction (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Existing DSM Programs																
Residential Conservation Program	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Residential Demand Conservation	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 Demand Conservation	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
WeCare	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
Commercial Conservation Program	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
DSM Programs (Case No. 2007-00319)																
Residential Conservation Program		1.2	1.5	3.5	5.7	8.0	10.2	12.5	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Residential Demand Conservation		3.6	4.8	9.6	14.4	18.1	21.9	24.5	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7
Commercial Demand Conservation		0.1	0.2	0.4	0.6	0.9	1.0	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
WeCare		1.5	2.3	4.6	6.9	9.2	11.5	13.8	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1
Commercial Conservation With Prescriptive Rebates		1.6	55.0	110.0	165.0	220.0	274.9	329.9	384.9	384.9	384.9	384.9	384.9	384.9	384.9	384.9
Residential High Efficiency Lighting			60.6	116.8	168.9	217.1	261.9	303.4	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8
Energy Star New Homes			0.4	1.2	2.8	4.6	6.7	9.1	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Residential HVAC Diagnostics & Tune Up			0.3	0.9	1.8	2.7	3.7	4.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Commercial HVAC Diagnostics & Tune Up			0.5	1.5	2.8	4.4	6.2	8.0	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
New DSM Programs																
Residential Window Films				0.4	0.9	1.7	2.4	3.1	3.9	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Residential Duct Sealing				0.2	0.7	1.4	2.2	2.9	3.7	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Residential Remove 2nd Refrigerator				3.4	10.3	17.2	24.1	31.0	37.9	44.8	44.8	44.8	44.8	44.8	44.8	44.8
Residential Responsive Pricing Rollout				9.4	18.9	28.3	37.8	47.2	56.7	66.1	66.1	66.1	66.1	66.1	66.1	66.1
Commercial Replace Resistance Heat				0.9	2.2	4.0	5.8	7.5	9.3	11.1	11.1	11.1	11.1	11.1	11.1	11.1
Commercial Duct Sealing				0.3	0.7	1.5	2.2	2.9	3.7	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Commercial High Efficiency Motors				0.2	0.6	1.0	1.4	1.9	2.3	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Commercial Geothermal Heat Pump				0.7	1.9	3.1	4.3	5.4	6.6	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Commercial Energy Management System				0.9	2.3	3.7	5.1	6.5	7.9	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Commercial Refrigeration Optimization				1.1	2.6	4.9	7.5	10.1	12.7	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Commercial Heat Pump Water Heater				3.5	8.7	14.0	19.2	24.5	29.7	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Commercial Refrigeration Case Covers				0.7	1.1	3.3	4.8	5.5	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7

Table 8.(3)(e)(3) – Cont.

Summer Peak Demand Reduction (MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Existing DSM Programs																
Residential Conservation Program	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Residential Demand Conservation	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0
Commercial Demand Conservation	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
WeCare	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	0.9	0.9	0.9
Commercial Conservation Program	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
DSM Programs (Case No. 2007-00319)																
Residential Conservation Program		0.2	0.9	1.7	2.7	3.7	4.7	5.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Residential Demand Conservation		10.0	31.1	52.0	73.1	89.4	105.7	117.4	126.8	126.8	126.8	126.8	126.8	126.8	126.8	126.8
Commercial Demand Conservation		0.6	1.9	3.0	4.3	5.6	6.6	7.5	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
WeCare		0.2	0.5	0.7	1.0	1.3	1.6	1.8	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Commercial Conservation With Prescriptive Rebates			22.2	44.0	65.7	87.5	109.3	131.1	152.9	152.9	152.9	152.9	152.9	152.9	152.9	152.9
Residential High Efficiency Lighting			4.3	8.3	12.0	15.4	18.6	21.6	24.3	24.3	24.3	24.3	24.3	24.3	24.3	24.3
Energy Star New Homes			0.1	0.4	0.9	1.6	2.3	3.1	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Residential HVAC Diagnostics & Tune Up			0.1	0.4	0.8	1.3	1.8	2.2	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Commercial HVAC Diagnostics & Tune Up			0.1	0.4	0.7	1.1	1.6	2.0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
New DSM Programs																
Residential Window Films				0.3	0.8	1.4	2.0	2.6	3.2	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Residential Duct Sealing				0.1	0.4	0.8	1.3	1.7	2.2	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Residential Remove 2nd Refrigerator				0.5	1.4	2.4	3.3	4.3	5.2	6.2	6.2	6.2	6.2	5.7	4.8	3.8
Residential Responsive Pricing Rollout				12.1	24.2	36.3	48.4	60.5	72.6	84.7	84.7	84.7	84.7	84.7	84.7	84.7
Commercial Replace Resistance Heat				0.1	0.2	0.4	0.6	0.7	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Commercial Duct Sealing				0.1	0.2	0.4	0.6	0.8	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Commercial High Efficiency Motors				0.1	0.2	0.4	0.6	0.7	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Commercial Geothermal Heat Pump				0.2	0.4	0.7	1.0	1.2	1.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Commercial Energy Management System				0.2	0.5	0.8	1.1	1.5	1.8	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Commercial Refrigeration Optimization				0.1	0.3	0.6	1.0	1.3	1.7	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Commercial Heat Pump Water Heater				0.2	0.4	0.7	1.0	1.2	1.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Commercial Refrigeration Case Covers				0.1	0.3	0.4	0.6	0.7	0.8	0.8	0.6	0.4	0.2	0.0	0.0	0.0

Table 8.(3)(e)(3) – Cont.

Winter Peak Demand Reduction (MW)

	07/08	08/09	09/10	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
Existing DSM Programs																
Residential Conservation Program	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Residential Demand Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Demand Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WeCare	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Commercial Conservation Program	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
DSM Programs (Case No. 2007-00319)																
Residential Conservation Program																
Residential Demand Conservation		2.6	5.3	7.9	9.3	12.0	13.4	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Commercial Demand Conservation		1.2	2.4	3.6	3.2	5.6	6.3	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
WeCare		0.6	1.2	1.8	2.6	3.0	3.5	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Commercial Conservation With Prescriptive Rebates			8.5	17.1	25.6	19.9	42.7	51.2	59.8	59.8	59.8	59.8	59.8	59.8	59.8	59.8
Residential High Efficiency Lighting			8.1	15.6	22.5	32.6	34.9	40.4	45.2	45.2	45.2	45.2	45.2	45.2	45.2	45.2
Energy Star New Homes			0.1	0.4	0.9	1.6	2.1	2.8	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Residential HVAC Diagnostics & Tune Up			0.1	0.3	0.5	0.8	1.0	1.3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Commercial HVAC Diagnostics & Tune Up			0.2	0.7	1.3	2.1	2.9	3.7	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
New DSM Programs																
Residential Window Films				0.0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Residential Duct Sealing				0.0	0.2	0.3	0.5	0.6	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Residential Remove 2nd Refrigerator				0.3	0.9	1.5	2.1	2.7	3.3	3.9	3.9	3.9	3.9	3.6	3.0	2.4
Residential Responsive Pricing Rollout				6.3	12.6	18.9	25.2	31.5	37.8	44.1	44.1	44.1	44.1	44.1	44.1	44.1
Commercial Replace Resistance Heat				0.2	0.4	0.8	1.1	1.5	1.8	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Commercial Duct Sealing				0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial High Efficiency Motors				0.1	0.2	0.4	0.5	0.7	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Commercial Geothermal Heat Pump				0.1	0.4	0.6	0.9	1.1	1.4	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Commercial Energy Management System				0.2	0.5	0.8	1.1	1.4	1.6	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Commercial Refrigeration Optimization				0.1	0.3	0.5	0.8	1.0	1.3	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Commercial Heat Pump Water Heater				0.1	0.4	0.6	0.8	1.0	1.2	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Commercial Refrigeration Case Covers				0.1	0.2	0.3	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6

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

The projected cost for the DSM programs are as shown below in Table 8.(3)(e)-4. The costs of the 12 new programs are reported in detail on Exhibit DSM-6 of the report titled *Screening of Demand-Side Management (DSM) Options* contained in Volume III, Technical Appendix.

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

Proposed Budget	2008	2009	2010	2011	2012	2013	2014	2015	2016
DSM Programs(Case No. 2007-00319)									
Residential Conservation Program	390	642	698	742	770	778	796	815	
Residential Demand Conservation	6,568	9,991	10,247	10,794	9,782	10,241	9,091	8,662	
Commercial Demand Conservation	112	436	399	451	439	431	448	432	
WeCare	1,769	1,729	1,738	1,788	1,868	1,893	1,947	2,003	
Commercial Conservation With Prescriptive Rebates	839	3,177	3,149	3,170	3,214	3,213	3,236	3,258	
Residential High Efficiency Lighting		3,435	3,389	3,397	3,416	3,447	3,490	3,543	
Energy Star New Homes		860	864	1,064	1,103	1,204	1,281	1,402	
Residential HVAC Diagnostics & Tune Up		205	340	392	487	483	492	538	
Commercial HVAC Diagnostics & Tune Up		190	268	328	412	455	467	512	
New DSM Programs									
Residential Window Films			198	234	294	300	307	313	320
Residential Duct Sealing			236	406	499	596	609	622	635
Residential Remove 2nd Refrigerator			415	725	737	748	760	772	785
Residential Responsive Pricing Rollout			5,438	6,193	6,987	7,924	8,780	9,667	10,586
Commercial Replace Resistance Heat			130	130	152	156	159	163	167
Commercial Duct Sealing			119	113	143	146	150	154	157
Commercial High Efficiency Motors			116	109	124	127	130	133	136
Commercial Geothermal Heat Pump			176	214	219	224	229	235	240
Commercial Energy Management System			161	177	182	186	190	195	199
Commercial Refrigeration Optimization			134	132	165	181	186	190	194
Commercial Heat Pump Water Heater			177	202	207	212	217	222	227
Commercial Refrigeration Case Covers			107	97	104	107	109	112	115

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

The existing and new DSM programs reduce the Companies' PVRR by $222 million, in 2007 dollars.

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 13 to 15 percent. In the development of the optimal IRP, the Companies retained a reserve margin target of 14 percent. Details of this study entitled *2008 Analysis of Reserve Margin Planning Criterion* (March 2008) 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 *2008 Optimal Expansion Plan Analysis* (March 2008) in Volume III, Technical Appendix. The in-service years for the units shown assume the Companies' base load forecast.

Table 8.(4)
Recommended 2008 Integrated Resource Plan

Year	Resource
2008	165 MW Purchase Power Contract (June-Sept only) for 2008-2009 11 MW DSM Initiatives (cumulative totals)*
2009	61 MW DSM Initiatives (cumulative totals)*
2010	**549 MW (75% of 732 MW) Trimble County Unit 2 Supercritical Coal**** 125 MW DSM Initiatives (cumulative totals)*
2011	191 MW DSM Initiatives (cumulative totals)*
2012	253 MW DSM Initiatives (cumulative totals)*
2013	314 MW DSM Initiatives (cumulative totals)*
2014	371 MW DSM Initiatives (cumulative totals)*
2015	**475 MW Combined Cycle Combustion Turbine** 425 MW DSM Initiatives (cumulative totals)*
2016	441 MW DSM Initiatives (cumulative totals)*
2017	
2018	
2019	**475 MW Combined Cycle Combustion Turbine**
2020	
2021	
2022	**155 MW Simple Cycle Combustion Turbine**

Note: Unit Ratings are Proposed Summer Net Ratings

* Case No. 2007-00319 approved programs and planned programs in 2008 IRP

** Case No. 2004-00507 – CPCN granted November 1, 2005

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

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecasted Peak Load	7132	7199	7293	7385	7508	7617	7705	7812	7916	8017	8117	8231	8330	8469	8566	8696
Existing Peak Reductions																
Interruptible		105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
Existing DSM		128	128	128	128	128	128	128	128	128	128	128	128	128	128	128
Case No. 2007-00319 DSM		11	61	111	161	207	252	292	330	330	330	330	330	330	330	330
Planned IRP08 Reduction (DSM)	0	0	0	14	29	45	62	77	93	109	109	109	108	108	107	106
Total Demand	7132	6956	6999	7027	7085	7132	7158	7210	7260	7345	7445	7560	7659	7798	7896	8028

Capacity From:																
Existing Resources	7521	7507	7467	8018	8020	8022	8024	8026	8022	8497	8497	8497	8497	8972	8972	8972
Planned Resources	0	0	0	0	0	0	0	0	475	0	0	0	475	0	0	155
Firm Purchases:																
Dynegy (MW)	0	165	165	0	0	0	0	0	0	0	0	0	0	0	0	0
OMU (MW)	169	168	167	0	0	0	0	0	0	0	0	0	0	0	0	0
OVEC (MW)	179	179	179	179	179	179	179	179	179	179	179	179	179	179	179	179
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	0	0	0	0	0	0	0	0	0	0
Total Supply	7869	8019	7978	8197	8199	8201	8203	8205	8676	8676	8676	8676	9151	9151	9151	9306

Reserve Requirements	998	974	980	984	992	998	1002	1009	1016	1028	1042	1058	1072	1092	1105	1124
Excess (Deficit)	-262	89	-1	186	122	71	43	-14	399	303	188	58	419	261	149	155
Reserve Margin (%)	10.3%	15.3%	14.0%	16.6%	15.7%	15.0%	14.6%	13.8%	19.5%	18.1%	16.5%	14.8%	19.5%	17.3%	15.9%	15.9%

Note: 2007 Peak Load is from Actual Peak on 8/9/2007; Capacity is from Planned

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

	07/08	08/09	09/10	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
Forecasted Peak Load	6357	5961	6055	6108	6241	6322	6397	6447	6492	6517	6638	6733	6898	6903	6975	7110
Existing Peak Reductions																
Interruptible		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing DSM		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Case No. 2007-00319 DSM		4	26	47	66	78	107	125	140	140	140	140	140	140	140	140
Planned IRP08 Reduction (DSM)		0	0	8	16	25	34	43	51	60	60	60	60	60	60	60
Total Demand	6357	5952	6024	6049	6154	6214	6251	6275	6296	6312	6433	6528	6693	6698	6770	6905
Capacity From:																
Existing Resources	7521	7507	7467	8018	8020	8022	8024	8026	8022	8497	8497	8497	8497	8972	8972	8972
Planned Resources	0	0	0	0	0	0	0	0	475	0	0	0	475	0	0	155
Firm Purchases:																
Dynegy (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OMU (MW)	169	168	167	0	0	0	0	0	0	0	0	0	0	0	0	0
OVEC (MW)	179	179	179	179	179	179	179	179	179	179	179	179	179	179	179	179
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	0	0	0	0	0	0	0	0	0	0
Total Supply	7869	7854	7813	8197	8199	8201	8203	8205	8676	8676	8676	8676	9151	9151	9151	9306
Reserve Requirements	890	833	843	847	862	870	875	878	881	884	901	914	937	938	948	967
Excess (Deficit)	622	1069	946	1302	1184	1117	1077	1052	1499	1480	1343	1234	1521	1516	1434	1435
Reserve Margin (%)	23.8%	32.0%	29.7%	35.5%	33.2%	32.0%	31.2%	30.8%	37.8%	37.4%	34.9%	32.9%	36.7%	36.6%	35.2%	34.8%

Note: 2007/08 Peak Load is from Actual Peak on 1/25/08; Capacity is from Planned

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.

Table 8.(4)(b)

Kentucky Utilities Company / Louisville Gas & Electric Company

Forecast Annual Energy (GWh)

1	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy Requirements	36,303	36,831	37,400	37,918	38,529	39,076	39,531	39,921	40,292	40,691	41,149	41,719	42,264	42,908	43,444	44,030

2 Energy by Fuel Type	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Coal	34,002	32,191	31,845	34,025	35,401	35,747	36,093	36,165	36,158	36,452	36,529	37,132	37,170	37,880	37,967	38,218
Gas	926	1,259	1,769	1,079	922	968	932	1,098	1,351	1,423	1,807	1,773	2,282	2,211	2,662	2,998
Oil	11	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
Hydro	176	313	335	358	379	400	417	441	441	442	441	441	441	442	441	441

3 Firm Purchases From Other Utilities	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OMU	1,289	1,599	1,878	763	0	0	0	0	0	0	0	0	0	0	0	0
OVEC	1,200	1,458	1,454	1,454	1,454	1,458	1,454	1,454	1,454	1,458	1,454	1,454	1,454	1,458	1,454	1,454
Other	371	3	5	1	1	2	2	2	0	1	1	2	0	1	1	1

4	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Purchases From Non Utility	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

5	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Reductions / Increases in Energy	0	(55)	(173)	(316)	(468)	(616)	(762)	(902)	(1,040)	(1,071)	(1,070)	(1,071)	(1,071)	(1,071)	(1,071)	(1,071)

Notes: 2007 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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy (GWh)	34,002	32,191	31,845	34,025	35,401	35,747	36,093	36,165	36,158	36,452	36,529	37,132	37,170	37,880	37,967	38,218
Total (000 Tons)	15,300	14,499	14,366	15,355	15,658	15,776	15,929	15,970	15,922	16,109	16,166	16,431	16,447	16,765	16,817	16,927
(000 MBTUs) Consumed	360,234	338,277	333,518	356,500	363,708	366,519	370,087	370,917	369,802	374,440	375,399	381,725	381,809	389,263	390,194	392,729

Gas	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy (GWh)	926	1,259	1,769	1,079	922	968	932	1,098	1,351	1,423	1,807	1,773	2,282	2,211	2,662	2,998
Total (000 MCF)	11,680	13,797	19,410	11,718	9,702	10,080	9,648	11,324	11,816	11,946	15,233	15,074	18,036	17,120	20,592	23,323
(000 MBTUs) Consumed	11,972	13,797	19,410	11,718	9,702	10,080	9,648	11,324	11,816	11,946	15,233	15,074	18,036	17,120	20,592	23,323

Oil	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy (GWh)	10.5	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)	3,640	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(000 MBTUs) Consumed	631	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Hydro	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy (GWh)	176	313	335	358	379	400	417	441	441	442	441	441	441	442	441	441

Notes: 2007 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 state-of-the-art software package from NewEnergy Associates called Strategist® to evaluate resource options. Strategist® is a proprietary, state-of-the-art 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 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 *2008 Optimal Expansion Plan Analysis* (March 2008) in Volume III, Technical Appendix.

Demand Side Management Resource Screening and Assessment

The Companies solicited input from the DSM Advisory Group regarding the DSM screening process. The Companies identified a broad range of DSM alternatives and developed a long list of alternatives. Each alternative on this long list was investigated and evaluated using a two-step screening process. The first phase was qualitative in nature, and each alternative was evaluated based on four criteria (see Table 8.(5)(c)-1 for a listing of the criteria). The second phase of screening was quantitative in nature and was performed using Quantec's DSM Portfolio Pro software. DSM Portfolio Pro is a PC-based software package developed by Quantec. It is a screening tool that determines the cost effectiveness of DSM programs by modeling their costs and benefits over a period of time. Additional detail on this process is contained in the report titled *Screening of Demand-Side Management (DSM) Options(March 2008)* contained in Volume III, Technical Appendix.

Supply Side Resource Screening Assessment

Both mature and emerging technologies were evaluated as supply side resources in the integrated resource planning process. The *Cummins and Barnard (C&B) E.ON U.S. Generation Options Technology Study* report dated December 2007 was utilized to perform the detailed screening analysis. C&B provided data on numerous mature and emerging technologies. Additional detail on this process is contained in the report titled *Analysis of Supply-Side Technology Alternatives* (April 2008) 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, the availability of existing as well as new generating units and purchases, weather uncertainties, potential regulation of CO_2 emissions, potential regulation 316b for cooling water intake structures, 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. Base coal price forecasts are adjusted by data received from Global Insight for the high and low fuel cost sensitivities. 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* (April 2008) contained in Volume III, Technical Appendix.

Technologies utilizing coal or natural gas are the only technologies in this evaluation to which the carbon tax is applicable. Hence, in addition to the base case for supply-side screening, a second case evaluates potential additional cost of CO_2 emissions in addition to costs associated with SO_2 and NO_x emissions. Rising concentrations of greenhouse gases may be responsible for undesirable climate changes, and several bills to restrict CO_2 emissions (a greenhouse gas) have been *proposed* (and are further discussed later in this section in a subsection entitled "*Potential Regulation of CO_2 Emissions*"). An alternative to the base case was conducted to evaluate the impact of CO_2 emissions. CO_2 emission costs were added to the dispatch costs of each technology affected by a carbon tax in a similar manner of that for SO_2. The carbon tax utilized in this evaluation is $10/ton, with sensitivities of $20/ton, and $40/ton. These rates are based on external analysis and *proposed* legislation.

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, four load forecasts were developed. Three of the four forecasts 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 fourth load forecast was constructed in conjunction with the "aggressive green" scenario. The details of and the basis for the various load forecasts are described in Volume II, Technical Appendix.

New Unit Estimated Costs

As the Companies have observed since filing the 2005 IRP, 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. The capital cost of coal units versus gas units has changed significantly over the last three years. In December 2007, Cummins and Barnard (C&B) provided the Companies with a report titled *Cummins and Barnard E.ON U.S. Generation Options Technology Study*. This 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* (April 2008) contained in Volume III, Technical Appendix, a base, low and high capital cost sensitivity was incorporated into the screening analysis.

Tax Incentives on Trimble County Unit 2

As a result of plans to construct one of the nation's most efficient and environmentally-friendly generating stations, the Companies received a $125 million tax credit from the U.S. Internal Revenue Service on November 30, 2006, as made available through the 2005 Energy Policy Act. This tax credit is the culmination of an award process which began in June 2006 with the Companies' application to the United States Department of Energy (DOE). DOE certification is a prerequisite for award eligibility.[2] The impact of this credit effectively lowers the new unit's costs by $125 million, and that benefit will be passed through to the customers.

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 mercury.

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 nitrogen oxides (NO_x) emitted from its steam generating plants. The Environmental Protection Agency (EPA) has capped NO_x emissions from electric generating units at 0.15 pounds per million BTUs of historic heat input (also known as the NO_x SIP Call).

The required NO_x reductions were achieved by the Companies through the installation of Selective Catalytic Reduction Systems (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

[2] In March 2008, certain environmental groups filed a lawsuit in federal court against DOE and the Treasury Department alleging that DOE failed to comply with the National Environmental Policy Act, in certifying the tax credits for various projects including the TC2 project.

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 occurred in 2002 and the most recent SCR came on-line in May 2004. In all, SCR installation was 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).

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 10-story building that houses a catalyst used to convert the NO_x emissions into the components of nitrogen and water. Like the annual sulfur dioxide (SO_2) allocation program under the Acid Deposition Control Provisions of the CAAA of 1990, EPA's NO_x regulations allow for the totaling of NO_x emissions over the Companies' entire system during the ozone season 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. Additional detail on the Companies' NO_x compliance plan was submitted with Case No. 2005-00162 in the report titled *2005 NO_x Compliance Study* (January 2005) contained in Volume III, Technical Appendix of that filing.

Additionally, the Clean Air Interstate Rule (CAIR) 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 will begin in 2009. Under the annual NO_x reduction program, allowable emissions will be reduced by approximately 40 percent in 2009 and 50 percent by 2015, compared to 2004 emission levels. Compliance will require year-round operation of the

SCR currently installed at Company facilities. For the ozone season NO_x reduction program, the currently administered NO_x SIP Call program will be replaced with CAIR ozone season NO_x emission caps in 2009. For Kentucky, the "new" ozone season cap is identical to the "old" ozone season cap for 2009-2014 and is reduced by about 15 percent for 2015 and beyond.

As an update from the 2005 IRP filing (Case No. 2005-00162) and 2006 CCN and Environmental Surcharge Compliance Plan filings regarding the need for more SCR installations to maintain compliance with NOx reduction requirements, KU has filed a motion with the KPSC to enter into the record for Case No. 2006-00206 the document titled: *Ghent 2 Selective Catalytic Reduction (SCR) Analysis Update-Timing of Construction (October 2007(Analysis Update))*. Per the KPSC Order of February 28, 2008, the Companies offer that the study provided in October 2007 is the most current evaluation on Ghent Unit 2 SCR and remains on file with the Case No. 2006-00206. In that analysis, it is shown that, at this time, construction of an SCR for Ghent Unit 2 does not represent the least-cost option for compliance with current and impending NOx regulations. Therefore, the construction will be delayed until future evaluations determine that construction of a SCR is the least-cost option.

Sulfur Dioxide

Although most of the Companies' larger coal-fired generating units are already fitted with Flue Gas Desulfurization units (FGDs), additional control of SO_2 is needed to comply with the multi-phased SO_2 reduction process mandated by 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 all existing FGD units to conserve the 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 is being supplemented in 2010 by the SO_2 program of the CAIR mentioned previously. CAIR's SO_2 program will reduce the Companies allowable SO_2 emissions by around 50 percent in 2010 and 65 percent in 2015. As a result of the Acid Rain Program and CAIR, the Companies have planned and have begun construction of a number of projects to reduce fleet-wide SO_2 emissions, including the installation of FGDs on Ghent Units 2[3] and 4 and E.W. Brown Units 1, 2, and 3. Installation of a FGD for Ghent Unit 3 was completed in May 2007. KU held an informal conference with the Commission staff on March 19, 2008 regarding the E.W. Brown and Ghent FGD installations and followed up by sending the updated report on March 28, 2008. This report titled Update to the *2004 SO_2 Compliance Strategy for E.ON U.S. Subsidiaries Kentucky Utilities Company and Louisville Gas and Electric Company* (March 2008) is contained in Volume III, Technical Appendix. There are many different designs of FGD equipment. The equipment planned for Ghent and E.W. Brown units are wet limestone, forced-oxidation systems, very similar to FGD equipment already in use at the Ghent, Trimble County, Cane Run, and Mill Creek Stations. These types of systems are among

[3] The existing FGD on Ghent 1 will be re-configured to Ghent Unit 2 and a new FGD will be added to Ghent Unit 1.

the highest in SO_2 capture efficiency. 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.).

Construction of these FGD systems will lessen the need to purchase SO_2 allowances. However, due to forecasted load and generation growth, it may still be necessary to purchase some allowances within this planning period to cover predicted emissions. Additional detail on the Companies' SO_2 compliance plan is provided in the report titled *Update to the 2004 SO_2 Compliance Strategy for E.ON U.S. Subsidiaries Kentucky Utilities Company and Louisville Gas and Electric Company (*March 2008*)* contained in Volume III, Technical Appendix.

Mercury

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 (CAMR) which established a two phase "cap and trade" program for reduction of mercury emissions from those units. A cap and trade program, which allows a company to target specific units for control to meet a system-wide target, is much more cost-effective than the unit-by-unit controls that would otherwise be applicable under Section 112(c). CAMR was projected to reduce mercury emissions from electric generating units to 38 tons by 2010 and 15 tons by 2018. While primarily aimed at controlling particulates, SO2, and NOx, conventional air pollution equipment such as electrostatic precipitators, FGDs, and SCRs, also removes some mercury from power plant emissions. EPA set the Phase I mercury reduction targets in CAMR at levels that were projected to be achieved as a "co-benefit" of complying with CAIR. CAMR required mercury monitors to be installed by January 1, 2009. If actual mercury emissions were determined to be greater than the estimated emissions, it might be necessary for a company to purchase emissions allowances or install additional controls to achieve the applicable targets.

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). EPA and other parties have moved for rehearing and parties may ultimately seek review before the U.S. Supreme Court. If the decision is not overturned on rehearing or appeal, EPA will be required to promulgate a new program governing hazardous air pollutant emissions from electric generating units. Unless EPA pursues additional efforts to establish a cap and trade program, it will be necessary for EPA to promulgate maximum achievable control technology (MACT) standards that would apply to all electric generating units that are major sources of hazardous air pollutants. Until such time as the pending appeals are exhausted and a final regulatory program is in place, there will continue to be substantial uncertainty as to future regulation of mercury and other hazardous air pollutants from electric generating units.

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 the Cummins & Barnard (C&B) report titled *E.ON US Generation Technology Options December 6, 2007*.

The Companies are two of 15 sponsoring companies of the Ohio Valley Electric Corporation (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 (ICPA) dated as of March 13, 2006, filed with and approved by the Commission in Case No. 2004-00396. Hence, commencing March 13, 2006, the anticipated summer capacity the Companies rely upon from OVEC is 179 MW net, with varying capacity during the remaining months due to unit maintenance schedules on the OVEC system.

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 the delay of CT 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 2007 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 15 percent. Due to extremely warm summer temperatures, on the peak day after contingencies, the actual operating margin was 5.9 percent in 2007. 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 4 p.m. Eastern Standard Time on August 9, 2007, the Companies' peak load was 7,132 MW. This is much higher than the Companies' previous all-time peak load (including buy-thru customers' load) of 6,863 MW which was established on August 3, 2006. The Companies' August 2007 capacity rating was 7,519 MW, 246 MW less than the winter capacity rating, and planned to have firm purchases from OMU (168 MW) and OVEC (179 MW) that total 347 MW. In general, the Companies have less installed capacity available in the summer season than in the winter season due to the effect of the summer weather conditions on the operating characteristics of each unit. At the time of the 2007 peak, the Companies' resources were composed of KU/LGE-owned units and 198 MW of native-load purchases from OVEC (114 MW) and OMU (84 MW). On the 2007 summer peak day, capacity available for native load from Company owned units was 385 MW less than the summer rating due to unit outages: due to the low river conditions, the Ohio Falls Station was unavailable (50 MW); two combustion turbines were unavailable due to forced outages (166 MW); coal unit derates attributed to a loss of 102 MW; and, a loss of 67 MW on the combustion turbines was attributed to the extreme ambient conditions. There were 222 MW of spot market purchases made at the time of the peak. These factors coupled with a higher than planned peak load (+231 MW) resulted in an operating margin of 5.9 percent or 422 MW, which exceeded the recommended minimum daily operating reserve requirement of approximately 174 MW, as outlined in detail in the "NERC Related Topics" subsection of Section 6. The Companies strive to maintain a level of daily operating reserve of approximately 174 MW to ensure a high degree of service continuity for its system and SERC.

Table 8.(5)(b)-1 shows pertinent system data for the 2007 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 2007. 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	**8/9/2007**
Hour (EST)	**16:00**
Day of Week	**Thursday**
Planned Capacity	
Utility Owned	7,588
Firm Purchase Contract	347
	7,935
Forecasted Peak Demand	**6,901**
Planned Reserve Margin	
Megawatts	1,034
Margin (%)	***15.0%***
Available Capacity [1]	
Utility Owned	7,134
Firm Purchase Contract	198
Spot market purchases [2]	222
	7,554
Actual Peak Demand	**7,132**
Outages	
Forced	166
Derate	169
Scheduled	0
	335
Actual Operating Margin	
Megawatts	422
Margin (%)	***5.9%***

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 2007 - August 2007 Native Load Experience

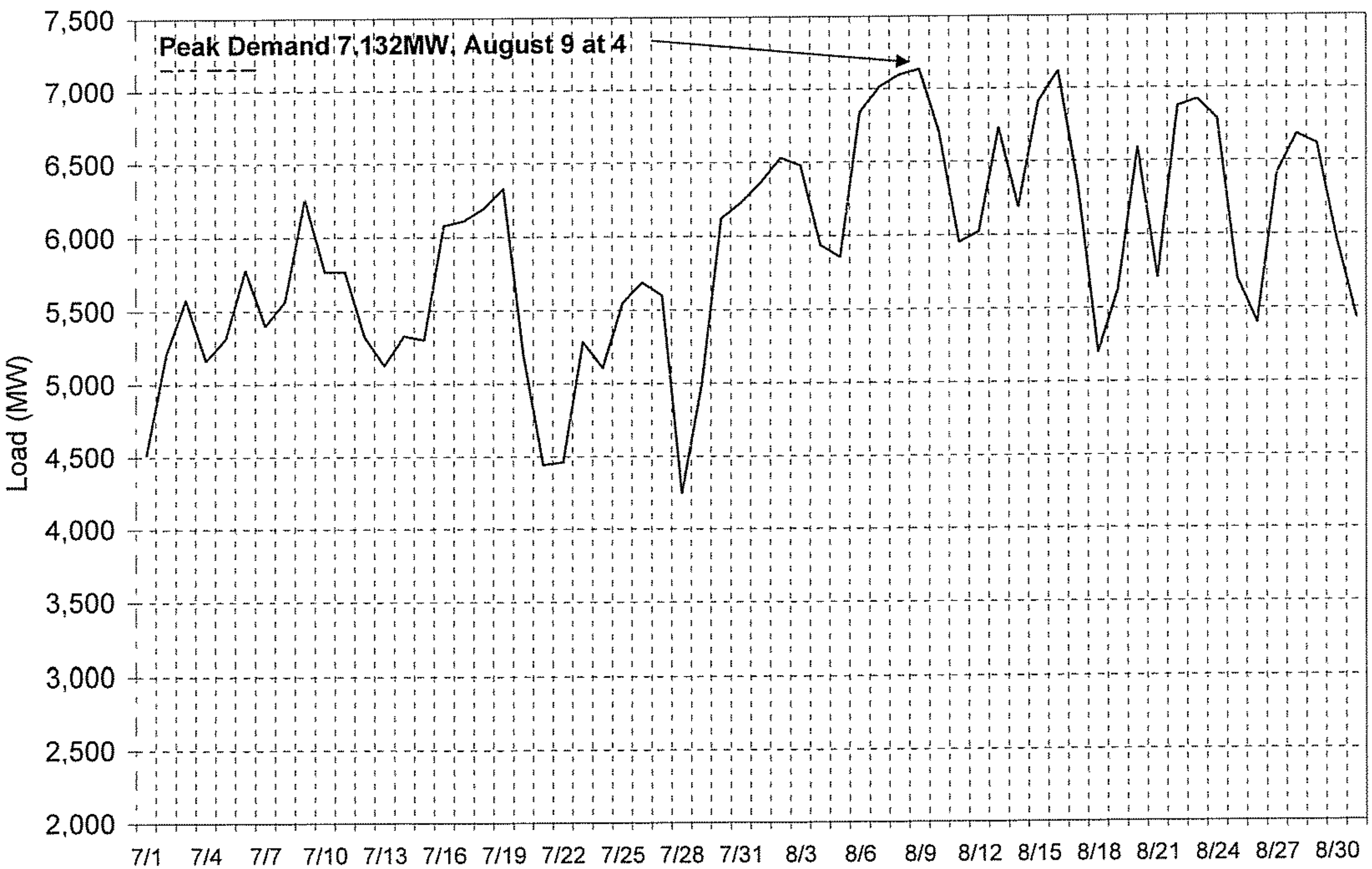


Figure 8.5b

Potential Regulation of CO_2 Emissions

In addition to the actions already mentioned regarding the Clean Air Act, Congress has been considering the promulgation of legislation to control emissions of carbon dioxide (CO_2). Such actions could be undertaken as part of an effort to reduce emissions of greenhouse gases (GHG) which may be responsible for global climate change. However, even with the potential future regulation of CO_2 emissions, no mandatory requirements are in place at this time. Some of the proposed measures are described as follows:

Kyoto Protocol – The 1997 Kyoto Protocol on climate change, if ratified by the Senate, would have required the U.S. to reduce emissions of six GHGs (including CO_2) between 2008 and 2012 to levels 7 percent below those of 1990. In late 2001, the Bush Administration rejected the Kyoto Protocol and indicated that the U.S. would not participate until developing countries also make commitments to participate in GHG limitations. President Bush stated that the treaty – worked out by the Clinton administration, but not ratified by the Senate – could cost millions of American jobs.

Credit for Voluntary Reductions – In February 2002, President Bush released his global climate change plan calling for an 18 percent reduction in GHG emissions over the next decade. The new climate change policy consists of voluntary goals rather than mandatory targets, and links GHG emissions to economic output. The goal is to lower the U.S. rate of GHG emissions from the 2002 level of 183 metric tons per million dollars of Gross Domestic Product (GDP) to 151 metric tons per million dollars of GDP in 2012. The president has also directed the DOE to ensure that companies that register voluntary reductions are not penalized under any future climate policies, and that the DOE give credit to companies that can show real emission reductions.

In more recent action in the GHG arena, the State of California signed into law requirements to reduce emissions to 1990 levels by 2020 starting in 2012. As of December 2007, 10 states have joined the Regional GHG Initiative (RGGI) which requires states (mainly focused in the Northeast) to meet a model set of regulations to reduce emissions by 10 percent by 2019 starting in 2009. As of the February 2008, 39 states were involved in one or more regional initiatives regarding climate change and clean energy.

On April 2, 2007, the United States Supreme Court issued an opinion holding that EPA has the authority to regulate GHG emissions from automobiles under the Clean Air Act. The ruling could potentially serve as a precedent for regulation of GHG emissions from other sources including electric generating units. As a result of the ruling, EPA has announced that it intends to explore potential GHG emission regulations for various industries as part of an advanced notice of proposed rulemaking (ANPR) expected to be published in the Spring of 2008. Under the ANPR, EPA will solicit comments from the general public on the various ways EPA could regulate GHG emissions under the Clean Air Act.

Additionally, Congress continues to have debates on various legislation regarding GHG issues. As previously stated, there are presently no regulations that would restrict the emission of CO_2; however, there are multiple proposals that may receive future consideration. To capture this possibility in the Companies' IRP process, a range of environmental cost adders for potential taxes on CO_2 emissions was included in the supply-side screening analysis. Details of this process can be found in the report titled *Analysis of Supply-Side Technology Alternatives* (April 2008) contained in Volume III, Technical Appendix.

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 does not establish cooling towers as BTA. Rather, this rule sets 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. This final rule applies to existing large electric generation facilities (i.e. those facilities which withdraw 50 million gallons per day or more of water and which use more than 25 percent for cooling purposes). Facilities have up to three and one-half years to perform aquatic studies and submit a Comprehensive Demonstration Study.

The Companies do have facilities that meet the applicability criteria for the Phase II final rule. However, on January 25, 2007, the U.S. 2nd Circuit Court made a ruling that portions of the final rule were illegal and remanded other portions back to EPA for revision. This means that another round of rulemaking will need to occur with full notice and public comment periods. EPA officially suspended the rule on July 9, 2007. EPA has advised states to issue permits using best professional judgment concerning 316(b) issues until a new regulation is issued.

Aquatic studies were performed at affected Company facilities from 2005 - 2007. Results of those studies will help determine how to react to any future new rule.

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 Unit 3 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

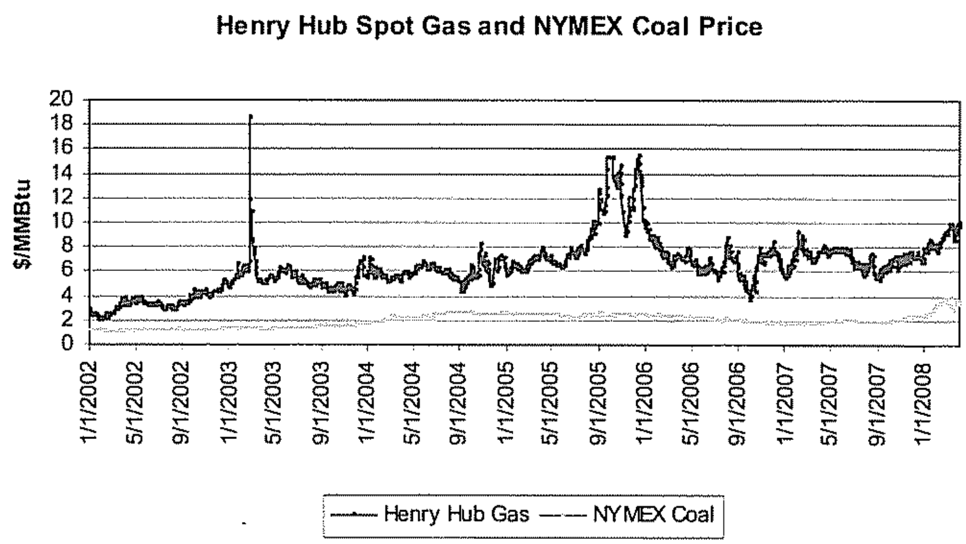
Aging Units

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2008)
Steam	Tyrone	3	71	1953	55
Steam	Green River	3	68	1954	54
Steam	Brown	1	101	1957	51
CT	Cane Run	11	14	1968	40
CT	Paddy's Run	11	12	1968	40
CT	Paddy's Run	12	23	1968	40
CT	Zorn	1	14	1969	39
CT	Haefling	1,2,3	36	1970	38

Fuel Cost Uncertainty

Natural gas prices are sensitive to market factors such as weather swings or supply disruptions – they exhibit higher levels of volatility in the colder months due largely to the seasonal pattern of space heating demand. The data in Table 8.(5)(b)-3 is from Global Energy's Velocity Suite and NYMEX Central Appalachian coal futures prompt contract settlement.

Table 8.(5)(b)-3



Moreover, there is always uncertainty associated with fuel transportation. Uncertainties affecting coal deliveries include railroad constraints and frozen and flooding rivers. With natural gas delivery come other uncertainties: since the amount of gas used for electric generation can vary substantially from hour to hour, meeting that changing demand requires the development of gas storage and other services with flexible delivery features.

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

Prior to the optimization process, a screening analysis of Demand-Side Management (DSM) options was conducted. The purpose of the screening analysis was to evaluate cost effective DSM options to use in Strategist® optimizations. The following is a summary of the DSM screening methodology and subsequent findings. A detailed report of the screening analysis titled *Screening of Demand-Side Management (DSM) Options* can be found in Volume III, Technical Appendix.

The Companies invited members of the DSM Advisory Group to submit proposals for DSM options to be analyzed. Each alternative on a list of potential alternatives was investigated and evaluated using a two-step screening process. The first step was qualitative in nature, where each alternative was evaluated based on four criteria. The alternatives that passed the first step underwent a second step of screening that was quantitative in nature. The quantitative screening process had two separate phases, which are discussed below. The DSM programs that passed the quantitative screening process were included with supply-side alternatives in the integrated analysis.

The qualitative analysis began with the selection of the criteria on which to base the comparison of DSM options. Based upon the Companies' objectives to provide low-cost, reliable energy to our customers, four criteria were selected. The next task was to assign weights or values to each of the criteria. The highest weights were assigned to the criteria judged to be the most important to develop a successful DSM program. The most important criterion was the cost effectiveness of peak demand reduction. Each potential DSM option was evaluated, based on a scale of 1 to 4, using the four criteria. The four criteria, their weights, and an explanation of each are shown in Table 8.(5)(c)-1.

Table 8.(5)(c)-1
Qualitative Screening Criteria

Criteria	Description	Weighting
Customer Acceptance	The degree to which an acceptable number of customers is willing to participate to create a successful program. The highest scores would be reserved for measures that have beneficial side effects, e.g., enhanced worker productivity or improvements in the quality of a product or service.	25%
Technical Reliability	The degree to which the technology is commercially available to evaluate this measure.	15%
Cost Effectiveness of Energy Conservation	The cost of this measure to reduce a kWh relative to the cost of generation in $/kWh.	25%
Cost Effectiveness of Peak Demand Reduction	The cost of this measure to reduce a kW relative to the cost of generation in $/kW.	35%

The programs that passed the qualitative screening process were modeled in more detail using Quantec's DSM Portfolio Pro software as part of the quantitative screening process. DSM

Portfolio Pro calculates the net present value of the quantifiable costs and benefits assignable to both the Companies and the customers participating in a DSM program. For each DSM initiative, DSM Portfolio Pro requires the administrative costs, participant's costs, life span of the technology, expected level of participation, expected level of free riders, and rate schedules. DSM Portfolio Pro calculates changes to the participant's bill, changes in the Companies' revenue, changes in production costs, and changes in the peak demand. The present value for each DSM alternative is calculated, by DSM Portfolio Pro, and reported as the costs and benefits using the five "California Tests." These five tests include the participant, utility cost, ratepayer impact measure (RIM), total resource cost (TRC), and societal cost tests. The participant test includes changes in all costs and benefits to the customer installing the DSM option. The TRC test combines the RIM and participant tests and indicates overall benefits of the DSM option to the average customer, whereas the RIM test considers all impacts to the non-participants.

The quantitative screening was set up in two phases. In Phase I, the cost to administer the program was not considered and it was assumed that the program had only one participant per Company. This phase was created to remove non-cost effective programs. If the benefits of a program do not exceed the cost of the program without the administration cost, then it will not pass with a higher penetration of customers and the added burden of the administrative costs. The only cost included in this phase was the incremental cost of the DSM alternative. Each program passing the Participant and TRC tests as part of Phase I of the quantitative screening process was put through a program design phase (Phase II). The costs to administer the programs and the expected levels of penetration were added to the programs that passed Phase I. Results of all five of the California tests were calculated as part of the Phase II evaluation with primary emphasis being placed on the Participant and TRC tests.

Twelve programs passed the quantitative screening process and were passed on to the optimization process.

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* (April 2008) can be found in Volume III, Technical Appendix.

Cummins & Barnard, Inc. (C&B) provided the Companies data for determining the relative cost and performance of current/advanced electric generation and storage technologies. 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. The base analysis includes the impact that SO_2 and NO_x emissions can have on selecting technologies. Current Clean Air Act and NO_x SIP Call regulations limit the emission of SO_2 and NO_x from certain generating facilities. Sensitivities are utilized to provide valuable information on how each technology will perform under various operating conditions. Some of the sensitivities contained in this analysis are based on variations in capital cost, technology operating efficiency (measured by heat rate), fuel cost and the addition of costs associated with controlling CO_2 emissions.

The sensitivities regarding capital cost, heat rate, and fuel costs each have three possible scenarios: base, low, and high, which results in 27 sensitivity combinations. The remaining sensitivities considered in the screening evaluation concerns CO_2 emissions. CO_2 emissions are a possibility in the future and evaluations which include CO_2 emissions costs are included in this analysis as an alternatives to the base case.

For each of the three sensitivity variables, high and low values were determined, in addition to the base values supplied by 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 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)-1 is a graphical representation of the base case least-cost technologies identified in Table 8.(5)(c)-2. 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 13 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 as addressed in

Analysis of Supply-Side Technology Alternatives (April 2008) in subsection "Base Analysis with SO_2 and NO_x Impact."

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

Capital Cost- Base **2007 ($/kW yr)**
Heat Rate- Base
Fuel Forecast- Base

Technology	0	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
					Capacity Factors						
Pumped Hydro Energy Storage - 500 MW	147	210	273	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	140	231	323	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - Peaking Capacity	172	290	408	526	644	762	880	998	1116	1234	1352
Simple Cycle GE 7EA CT - Peaking Capacity	128	267	405	544	683	821	960	1099	1237	1376	1515
Simple Cycle GE 7FA CT - Peaking Capacity	102	227	351	476	601	725	850	975	1099	1224	1349
Combined Cycle GE 7EA CT - Intermediate Load	191	273	354	436	518	599	681	763	844	926	1008
Combined Cycle GE 7FA CT - Intermediate Load	144	215	287	358	430	501	572	644	715	786	858
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	122	193	264	336	407	478	549	620	692	763	834
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	104	175	245	316	386	457	528	598	669	739	810
Siemens 5000F CC CT - Intermediate Load	134	206	277	349	421	492	564	635	707	779	850
Humid Air Turbine Cycle CT - 366 MW	132	233	333	434	535	635	736	837	937	1038	—
Kalina Cycle CC CT - 282 MW	145	206	268	329	390	452	513	574	636	697	—
Cheng Cycle CT - 140 MW	151	225	299	373	447	521	595	669	742	816	—
Peaking Microturbine - 0 03 MW	422	590	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	456	597	738	879	1021	1162	1303	1444	1585	1726	1867
Subcritical Pulverized Coal - 250 MW	331	352	374	395	416	437	459	480	501	523	544
Subcritical Pulverized Coal - 500 MW	291	312	334	355	376	397	419	440	461	483	504
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	317	337	357	377	397	417	437	457	477	497
Circulating Fluidized Bed - 250 MW	330	352	373	395	416	438	459	481	502	524	545
Circulating Fluidized Bed - 500 MW	293	314	336	357	379	400	421	443	464	486	507
Supercritical Pulverized Coal - 500 MW	299	319	339	359	379	399	419	439	459	479	499
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	322	342	361	380	400	419	438	458	477	496
Supercritical Pulverized Coal - 750 MW	277	298	318	339	359	380	400	421	441	462	482
Supercritical Pulverized Coal. High Sulfur - 750 MW	280	299	319	338	357	377	396	416	435	454	474
Pressurized Fluidized Bed Combustion	412	436	461	485	510	534	559	583	608	—	—
1x1 IGCC	368	388	407	427	446	466	486	505	525	—	—
2x1 IGCC	327	347	366	386	405	425	444	464	483	—	—
2x1 IGCC, High Sulfur	327	345	363	382	400	418	436	454	473	—	—
Subcritical Pulverized Coal - 500 MW - CCS	524	555	585	616	646	677	708	738	769	799	830
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	532	561	590	619	648	677	706	735	764	793	823
Circulating Fluidized Bed - 500 MW - CCS	532	563	594	624	655	686	717	748	779	809	840
Supercritical Pulverized Coal - 500 MW - CCS	531	560	589	618	646	675	704	733	762	791	819
Supercritical Pulverized Coal, High Sulfur - 500 MW - CCS	538	566	593	621	649	677	704	732	760	788	815
Supercritical Pulverized Coal - 750 MW - CCS	501	530	559	588	617	646	675	704	733	762	791
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	505	533	560	588	615	643	670	698	725	753	780
1x1 IGCC - CCS	510	533	557	580	604	627	651	674	697	—	—
2x1 IGCC - CCS	462	485	509	532	556	579	603	626	649	—	—
2x1 IGCC. High Sulfur - CCS	464	486	509	531	553	576	598	620	643	—	—
Wind Energy Conversion - 50 MW	259	248	237	225	—	—	—	—	—	—	—
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	506	507	—	—	—	—	—	—	—	—	—
Solar Thermal. Parabolic Dish - 1.2 MW	734	734	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	771	772	773	773	773	774	774	—	—	—	—
Solar Thermal, Solar Chimney - 50 MW	646	646	646	645	—	—	—	—	—	—	—
MSW Mass Burn - 7 MW	1741	1712	1683	1653	1624	1595	1566	1537	—	—	—
RDF Stoker-Fired - 7 MW	1665	1747	1829	1912	1994	2076	2158	2241	2323	—	—
Landfill Gas IC Engine - 5 MW	455	494	533	572	611	651	690	729	768	807	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	512	536	559	582	605	629	652	675	698	721
Sewage Sludge & Anaerobic Digestion - 085 MW	693	689	685	681	676	672	668	663	656	649	—
Bio Mass (Co-Fire)	324	344	363	383	402	422	441	461	480	500	519
Molten Carbonate Fuel Cell - 300 kW	463	542	621	701	780	859	938	1017	1096	1176	—
Spark Ignition Engine - 5 MW	402	491	580	669	758	847	936	1025	1114	1203	—
Hydroelectric - New - 30 MW	473	467	462	456	449	—	—	—	—	—	—
Ohio Falls 9-10	293	287	281	273	—	—	—	—	—	—	—
Minimum Levelized $/kW	102	175	237	225	357	377	396	416	435	435	428

Figure 8.(5)(c)-1
Least Costly Technologies For Further Analysis
Base Capital, Base Heatrate, Base Fuel

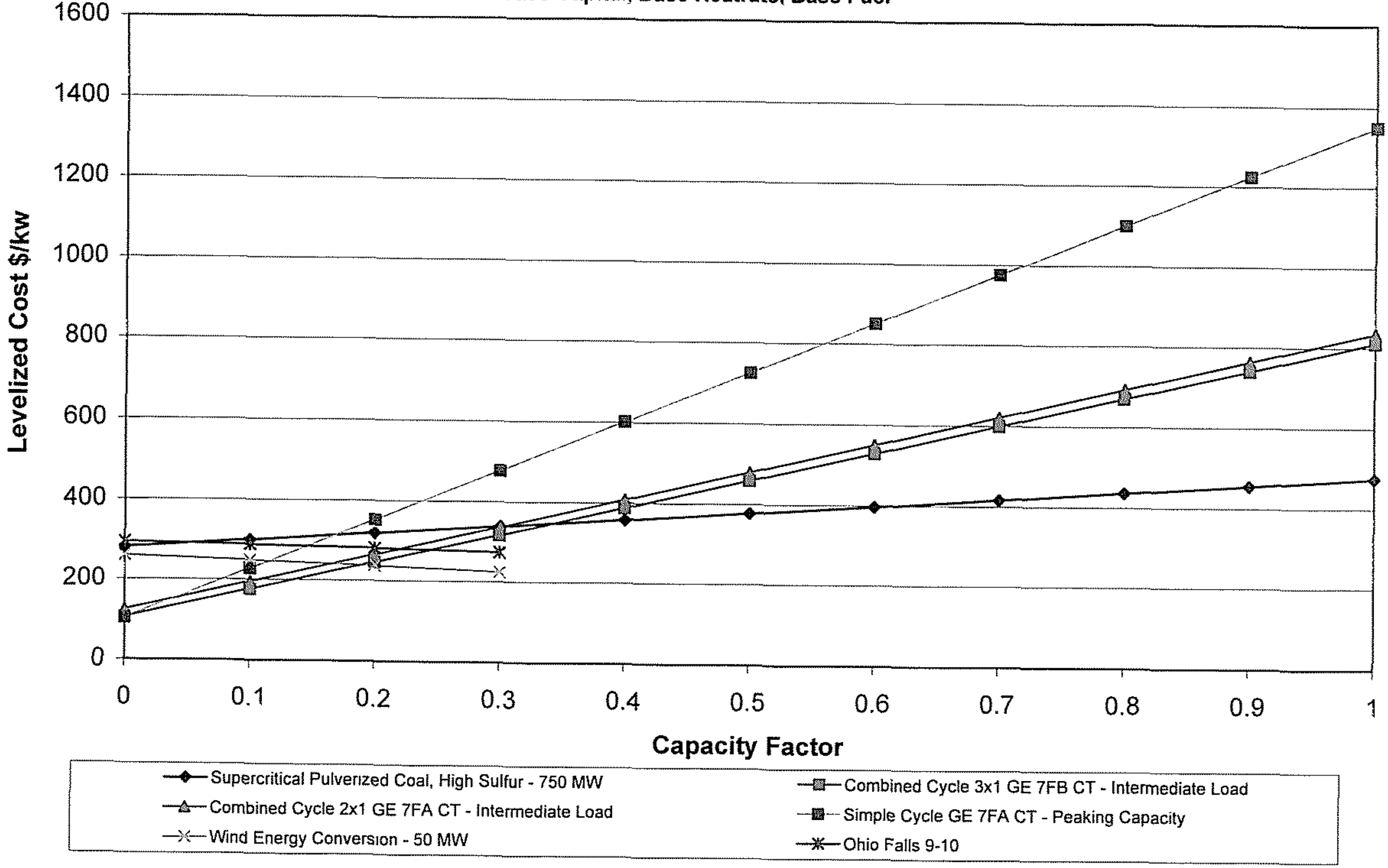


Figure 8.(5)(c)-1

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

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

Supercritical Pulverized Coal, High Sulfur
Combined Cycle 3x1 GE 7FB Combustion Turbine
Combined Cycle 2x1 GE 7FA Combustion Turbine
Run of River-Ohio Falls Expansion (Units 9 and 10)
Wind Energy Conversion
Simple Cycle GE 7FA Combustion Turbine

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, state-of-the-art 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 restraints 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 ready.

The optimal resource strategy is determined based on a minimum expected Present Value of Revenue Requirements (PVRR) criterion over a 30-year planning horizon and subject to certain constraints, including a target reserve margin of 14 percent and unit operating characteristics. As precursors to the optimization process, two independent technology screening analyses were conducted, one for supply-side alternatives and the other for demand-side management programs as discussed above.

Sensitivities developed around seven key areas: load; unit retirements; first year available for baseload addition; various options with and without DSM, CO_2; capital cost of the coal and gas units; and gas transportation for combustion turbines; and combined cycle combustion turbines. All of these sensitivities were evaluated in computer optimization using Strategist®. The sensitivity cases provided support for the recommended plan.

A more detailed description of the process can be found in the report titled *2008 Optimal Expansion Plan Analysis* (March 2008) 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 2022 is shown below in Table 8.(5)(c)-4.

Table 8.(5)(c)-4
Recommended 2008 Integrated Resource Plan

Year	Resource
2008	165 MW Purchase Power Contract (June-Sept only) for 2008-2009 11 MW DSM Initiatives (cumulative totals)*
2009	61 MW DSM Initiatives (cumulative totals)*
2010	**549 MW (75% of 732 MW) Trimble County Unit 2 Supercritical Coal** 125 MW DSM Initiatives (cumulative totals)*
2011	191 MW DSM Initiatives (cumulative totals)*
2012	253 MW DSM Initiatives (cumulative totals)*
2013	314 MW DSM Initiatives (cumulative totals)*
2014	371 MW DSM Initiatives (cumulative totals)*
2015	**475 MW Combined Cycle Combustion Turbine** 425 MW DSM Initiatives (cumulative totals)*
2016	441 MW DSM Initiatives (cumulative totals)*
2017	
2018	
2019	**475 MW Combined Cycle Combustion Turbine**
2020	
2021	
2022	**155 MW Simple Cycle Combustion Turbine**

Note: Unit Ratings are Proposed Summer Net Ratings

* Case No. 2007-00319 approved programs and planned programs in 2008 IRP

** Case No. 2004-00507 – CPCN granted November 1, 2005

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 December 2007, an analysis was completed which analyzed the Companies' appropriate margin level. This study indicated a 13-15 percent range of reserve margin would provide a reliable system to meet customers' demand, and a target reserve margin of 14 percent is used in this IRP. Details of this analysis are outlined in the study titled *2008 Analysis of Reserve Margin Planning Criterion* (March 2008) which can be found in Volume III, Technical

Appendix. This study is summarized below and is a continuation of efforts to determine the reserve margin level that best balances reliability and cost.

The key variables for studies of this type are the number and length of planned generating unit outages and maintenance outages; generating unit forced and/or equivalent forced outage rates; the availability of purchase power capacity for import; customers perceived cost of unserved/emergency energy; and the expected system load and load factor. The availability of the Companies' existing units is based on historical data. The availability of proposed generating units is such that it falls within the accepted availability for units of a given type, size and class. Pace Global Energy Services was engaged by Cummins and Barnard to perform an unserved energy study for the Companies in October 2007 to determine a more current base unserved energy cost. Based on a careful assessment of the studies available for review, Pace Global recommended a value of approximately $15/kWh be adopted as a proxy for the value of unserved energy. Sensitivity values around the base customer perceived value of unserved energy cost were evaluated, as were market purchases, a high annual load forecast, and finally unit availability sensitivities. The Strategist® computer model was used in the evaluation and the minimization of present value of revenue requirements is the primary decision factor.

Optimization study runs were used to create a least costly ordering of supply-side options for various reserve margin levels (from 7 to 18 percent, in increments of 1 percent) given each set of key variables. This methodology was repeated for all possible combinations of the key variables over a range of reserve margins. Cases with reserve margins that showed PVRR within a small variance (0.5 percent) of the minimum PVRR case were considered as economically equivalent.

Given the base case assumptions used in this study, together with the detailed sensitivity analysis performed on the purchase power market, unit availability, customer perceived unserved energy cost, annual and summer only load forecast, a target reserve margin in the range of 13-15 percent would be considered optimal. For purposes of developing an optimal IRP, a target reserve margin of 14 percent is being used in this study.

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 10 million ton reduction in SO_2 emissions and a two million ton reduction in NO_x emissions from the 1980 levels in the 48 contiguous states. As the CAIR is implemented in

2009 for NO_x and 2010 for SO_2, further reductions in SO_2 and NO_x will aid in reducing ozone and fine particulate ($PM_{2.5}$) in the affected regions of the country (including Kentucky).

Sulfur Dioxide (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. Allowances were allocated, in tons, to affected units at a level equivalent to 1.2 lbs SO_2/mmBtu using the average heat input value obtained from fuels used between 1985 and 1987.

Clean Air Interstate Rule (SO_2 portion)

As stated previously in section 8.(5)(b), the CAIR introduces a need for further reduction of SO_2 emissions. Continuing the use of the cap-and-trade emission allowance program, the Companies must retain enough emission allowances to cover the level of emissions that occur. CAIR will use 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 with affected facilities will surrender allowances at a greater rate than is currently required: on a 2-for-1 and 3-for-1 basis, during Phases I and II, respectively. One caveat is that pre-2010 Acid Rain Program SO_2 allowances (i.e., banked allowances) would retain their full value. The result is that the Companies will be required to purchase SO_2

allowances from the market or find another way to offset the SO_2 emissions in excess of the emission allowance "caps" over the two phases of the regulation.

To curtail the need for purchasing SO_2 allowances, the Companies have completed construction of an FGD for KU's Ghent Unit 3 and have begun construction of FGD equipment for KU's Ghent Units 2[4] and 4 and E.W. Brown Units 1, 2, and 3. At this time, completion of this construction is anticipated at Ghent in 2009 and at E.W. Brown in 2010. Additional detail on the Companies' SO_2 compliance plan is provided in the report titled *Update to the 2004 SO_2 Compliance Strategy for E.ON U.S. Subsidiaries Kentucky Utilities Company and Louisville Gas and Electric Company* (March 2008) contained in Volume III, Technical Appendix.

Nitrogen Oxide (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

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

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 State Implementation Plan (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 National Ambient Air Quality Standards (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 maintains 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 State Implementation Plans (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. Implementation of the rule will be based on a "cap-and-trade" allowance program similar to the NO_x SIP Call regulation. Under CAIR for NO_x, the EPA has allocated a predetermined amount of allowances to each state and the states have determined how to allocate these to individual affected units. Additionally, emissions will begin 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 means that controls, currently considered for seasonal operation (i.e., SCRs), will have to be run year-round and may mean additional NO_x control installation by the Companies or the purchasing of allowances will be necessary to meet the reduction requirements over the two phases of the regulation. As mentioned in Section 8.(5)(b), Kentucky Utilities has filed a motion with the KPSC to enter into the record for Case No. 2006-00206 the document titled: *Ghent 2 Selective Catalytic Reduction (SCR) Analysis Update-Timing of Construction (October 2007(Analysis Update))*. Per KPSC Orders of February 28, 2008, the Companies offer that the study provided in October 2007 is the most current evaluation on Ghent Unit 2 SCR and remains on file with the Case No. 2006-00206. In that analysis, it is shown that, at this time, construction of an SCR for Ghent 2 does not represent the least-cost option for compliance with current and impending NOx regulations. Therefore, the construction will be delayed until future evaluations determine that construction of a SCR is the least cost option.

Clean Air Mercury Rule

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 (CAMR) which established a two phase "cap and trade" program for reduction of mercury emissions from those units. A cap and trade program, which allows a company to target specific units for control to meet a system-wide target, is much more cost-effective than the unit-by-unit controls that would otherwise be applicable under Section 112(c). CAMR was projected to reduce mercury emissions from electric generating units to 38 tons by 2010 and 15 tons by 2018. While primarily aimed at controlling particulates, SO_2, and NOx, conventional air pollution equipment such as electrostatic precipitators, FGDs, and SCRs, also removes some mercury from power plant emissions. EPA set the Phase I mercury reduction targets in CAMR at levels that were projected to be achieved as a "co-benefit" of complying with CAIR. CAMR required mercury monitors to be installed by January 1, 2009. If actual mercury emissions were determined to be greater than the estimated emissions, it might be necessary for a company to purchase emissions allowances or install additional controls to achieve the applicable targets.

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). EPA and other parties have moved for rehearing and parties may ultimately seek review before the U.S. Supreme Court. If the decision is not overturned on rehearing or appeal, EPA will be required to promulgate a new program governing hazardous air pollutant emissions from electric generating units. Unless EPA pursues additional efforts to establish a cap and trade program, it will be necessary for EPA to promulgate maximum achievable control technology (MACT) standards that would apply to all electric generating units that are major sources of hazardous air pollutants. Until such time as the pending appeals are exhausted and a final regulatory program is in place, there will continue to be substantial uncertainty as to future regulation of mercury and other hazardous air pollutants from electric generating units.

New National Ambient Air Quality Standards (NAAQS) for 8-hr Ozone and $PM_{2.5}$

8-hour 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 is 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 (VOCs) 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.

All states were required to submit their recommended air quality designations to the EPA for the 8-hour ozone standard based on 2001, 2002 and 2003 air monitoring data. Kentucky submitted their recommendations for designations on July 14, 2003. 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 affect on June 15, 2004. The Companies have coal-fired electric generating units in only one of the non-attainment counties, Jefferson.

Through a request submitted by the Kentucky Division for Air Quality, EPA approved, on July 5, 2007, a redesignation of the Kentucky portion of the bi-state Louisville area (which includes Jefferson, Oldham and Bullitt counties) to attainment status for the 8-hour ozone standard. Jefferson County has adopted measures to assure that attainment status for this 8-hour ozone standard is maintained. However, EPA is required to review the effectiveness of NAAQS every five years. EPA has begun that process again for ozone.

On March 12, 2008, EPA lowered the primary standard to 0.075 ppm. Several counties in Kentucky have recent monitoring data that are above these levels. There are also proposals under review of the secondary standard. This issue will continue to be reviewed by the Companies.

$PM_{2.5}$

In 1997, EPA also 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). $PM_{2.5}$ is considered a threat to the public health because it has been associated with lung cancer, child development problems, and premature mortality.

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. As noted previously, gaseous emissions of SO_2 and NO_x can transform into sulfates and nitrates in the atmosphere.

On February 20, 2004, Kentucky submitted recommendations for non-attainment $PM_{2.5}$ designations to the EPA for Jefferson and Fayette counties, based on data collected in 2001, 2002, and 2003. EPA released the final designations on December 17, 2004, which included Boone, Boyd, Bullitt, Campbell, Fayette, Jefferson, Kenton, part of Lawrence, and part of Mercer counties as non-attainment for $PM_{2.5}$. On April 5, 2005, EPA removed Fayette and Mercer from the list of non-attainment areas. Finally, on March 29, 2007, EPA issued the Clean Air Fine Particulate Implementation Rule, which defined $PM_{2.5}$ SIP requirements. Under the rule, compliance with CAIR will satisfy the requirements for SO_2 and NO_x at it relates to determination of Reasonably Achievable Control Technology (RACT) and Reasonably Achievable Control Measures (RACM) with a few caveats. The state must fulfill its CAIR reductions through reductions from electric generating units. States may "go beyond CAIR" if necessary to attain the standard. Electric generating units in non-attainment areas are subject to RACT/RACM for direct $PM_{2.5}$ emissions. States must meet the standard by April 2015 (with the potential for a five-year extension) by following the requirements of a SIP. A SIP is required to be submitted to EPA for all non-attainment areas in April 2013.

On September 21, 2006, EPA released a revision to the PM NAAQS with an April 2010 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. The annual $PM_{10-2.5}$ standard was revoked. At this time, Jefferson County is expected to be the only county impacted by the new NAAQS.

As usual, these new standards will lead to regulations that could 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

EPA developed 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.

In April 1999, final regulations were issued. The final rule 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 will require 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.

Cane Run Units 5 and 6, E.W. Brown Units 2 and 3, Ghent Units 1 and 2 and Mill Creek Units 1-4 were identified as being "BART eligible". Their emissions were evaluated for their 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. With that knowledge, an engineering analysis was performed following the BART guidelines to determine what control technology should be applied to reduce the impact. 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. It has not yet been published for public notice. Final approval of the SIP should be made in late 2008/early 2009. Affected facilities typically have three years to comply with SIP requirements.

Additionally, CAVR contains review time periods in which an evaluation is made on how well progress is being made to meet 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 – 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 (NPDES) data, and (2) ranked fourth for toxic loadings based on Toxic Release Inventory (TRI) 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. Depending on the results of that study and possible changes in effluent guidelines, capital investments for treatment facilities could be required within the time period of this IRP document. 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 2008 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 2008 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 7.85 percent. This value is the combined Company before-tax incremental weighted average cost of capital.

Table 9

Kentucky Utilities Company and Louisville Gas & Electric Company

Resource Assesment and Acquisition Plan

Financial Information

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1	**Present Value of Revenue Requirements ($ million)**	[redacted]														
2	**Discount Rate**	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%
	Inflation Rate	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%
3	**Real Value of Revenue Requirements ($ million)**	[redacted]														
	Nominal Value of Revenue Requirements ($ million)	[redacted]														
4	**Average Rate (Cents/kWh)**	[redacted]														

Notes:

1. Present Value and Real Value Revenue Requirements are in 2007$.
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 2008 through 2017.