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5. PLAN SUMMARY

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

Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") are investor-owned public utilities supplying electricity and natural gas to customers primarily in Kentucky. Both KU and LG&E are subsidiaries of LG&E Energy LLC which is a member of the E.ON AG (NYSE: EON; Frankfurt: EOA) family of companies. Effective December 30, 2003, LG&E Energy LLC, a Kentucky limited liability company, was the successor by assignment and subsequent merger of all of the assets and liabilities of LG&E Energy Corp., a Kentucky corporation. 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.

KU and LG&E have a joint net summer generation capacity of 7,610 MW as shown in Table 5.(1)-1 and serve 903,834 electricity customers over a transmission and distribution network covering some 27,000 square miles. KU supplies electric service in an area that covers approximately 6,600 non-contiguous square miles in 77 counties of Kentucky and 5 counties in southwestern Virginia that are serviced by Old Dominion Power Company ("ODP"). KU also sells electric energy at wholesale for resale to 11 municipalities in Kentucky and Berea College (a privately-owned utility serving the city of Berea). LG&E supplies electricity and natural gas to customers in the Louisville metropolitan area and 16 surrounding counties covering 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), and Street Lighting customers. 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 20 coal-fired units operated at 7 different steam generating stations: E. W. Brown, Cane Run, Ghent, Green River, Mill Creek, Trimble County, and Tyrone. Also, there are 2 oil-fired units operated at 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 Companies do not own any nuclear facilities. The generating units for KU and LG&E are summarized in Tables 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	2004 Summer Net Capacity (MW)	2004 Winter Net Capacity (MW)
KU Coal	2876	2874
KU CT – Gas	1499	1669
KU – Oil	58	63
KU Hydro	24	24
Total KU	**4457**	**4630**
LGE Coal	2418	2440
LGE CT – Gas	687	764
LGE Hydro	48	32
Total LGE	**3153**	**3236**
Coal	5294	5314
CT – Gas	2186	2433
Oil	58	63
Hydro	72	56
Total	**7610**	**7866**

The Companies' net summer generating capability in 2004 was 7,610 megawatts. The Companies have purchase agreements in place with Electric Energy Incorporated ("EEInc."), Owensboro Municipal Utilities ("OMU") and Ohio Valley Electric Corporation ("OVEC"). The Companies' ownership in EEInc. is 20%. The Companies receive 9.5% of the OVEC capacity and energy; the OVEC sponsorship is further described in Section 5.(4). The Companies' highest combined system peak demand of 6,513 megawatts occurred on August 5, 2002. LG&E experienced its highest system peak demand of 2,623 megawatts on that date at hour ending 15:00 EST. On that date, KU's highest peak demand was 3,899 megawatts at hour ending 16:00 EST. However, KU has superseded that day's peak with their highest system peak demand occurring on January 18, 2005 with a (non weather-normalized) demand of 4,065 megawatts at 8:00 EST.

This report is a snapshot in time of an ongoing resource planning process, which the Companies believe is fundamental to all corporate planning. The various sections of this report define ongoing and planned activities that collectively make up this process. The Companies review the planning alternatives and decisions annually as part of the ongoing resource planning process. This process is continually evolving, and as such is a dynamic effort using state-of-the-art techniques and models as well as timely and pertinent information. All planning decisions are based on certain sets of assumptions and are subject to varying degrees of risk and uncertainty. It is only through an ongoing planning process that there is assurance that the interests of the Companies' constituent groups are adequately addressed.

Meeting the needs of the Companies' customers requires the availability of sufficient resources to serve customer demand. Additional resources must also be available should there be an unexpected loss of generation, generation equipment problems, extreme weather conditions, or unanticipated load growth. Existing capacity resources consist of company-owned generating units and contracted purchased power from other generating entities. In the integrated planning process, the economics and practicality of supply-side and demand-side options are examined to determine cost-effective responses to customers' needs. The Companies' resource planning process encompasses: 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 an economic plan from the available resource options. While the Integrated Resource Plan ("IRP") represents the Companies' analysis of the best options to meet customer needs at a given point in time, the action plan is reviewed and re-evaluated prior to implementation. In addition to net Present Value Revenue Requirement ("PVRR"), which establishes the ordering of the IRP options, rate impact, shareholder effects, risks and flexibility are typically considered prior to making financial commitments.

While preparing this resource assessment and acquisition plan, the Companies were in possession of the Commission Staff Report on the 2002 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company dated December 2003. This report summarizes the Commission Staff's review of the Companies' 2002 filing and offered suggestions and recommendations to be considered in subsequent filings. 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

Robust forecasting of energy and demand is of vital importance for the prudent planning and control of the Companies' operations. The load forecast is the basis upon which the Companies make decisions on the construction of facilities such as power plants, transmission lines, and substations, all of which are necessary to provide economical and reliable service.

The modeling techniques in use within 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 2005 IRP.

Models & Methods

KU's and LG&E's energy forecasting approach relies upon econometric modeling, together with the collection of specific growth outlook information from its largest customers. The econometric approach establishes the historical relationships between electric sales and the 'independent' explanatory variables that underlie sales development (e.g. output growth and household formation). This approach may be applied to forecast customer numbers, energy sales, or use-per-customer. Separate econometric models are prepared for each sales jurisdiction and each 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 eleven municipally-owned utilities in Kentucky and to Berea College). The distribution of KU sales by jurisdiction in 2004 was: 85.9 percent Kentucky-Retail; 4.5 percent Virginia-Retail; and 9.6 percent Wholesale. Within each jurisdiction, the forecast typically distinguishes several classes of customer 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.

Both KU and LG&E forecasts incorporate medium- and long-term models, with the specification and length of historical data varying by class. In general, medium-term models using monthly data determine the outlook for the first five forecast years, with long-term models based on annual or seasonal data used for the remainder of the forecast horizon. A notable exception is Residential sector modeling of use-per-customer, which uses monthly data in combination with long-term structural trends interpolated to monthly data for both medium-term and long-term forecasting.

Residential energy sales modeling for both utilities incorporates elements of end-use forecasting - such as baseload, heating and cooling components of sales - which addresses 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/LG&E regarding their outlook. This process allows for market intelligence to be directly incorporated into the sales forecast.

Once complete, the energy forecast of each utility is converted from a billed to calendar basis and adjusted for Company use and losses. Monthly energy requirements are then associated with a typical load profile to generate hourly demand forecasts for each utility and for the combined company.

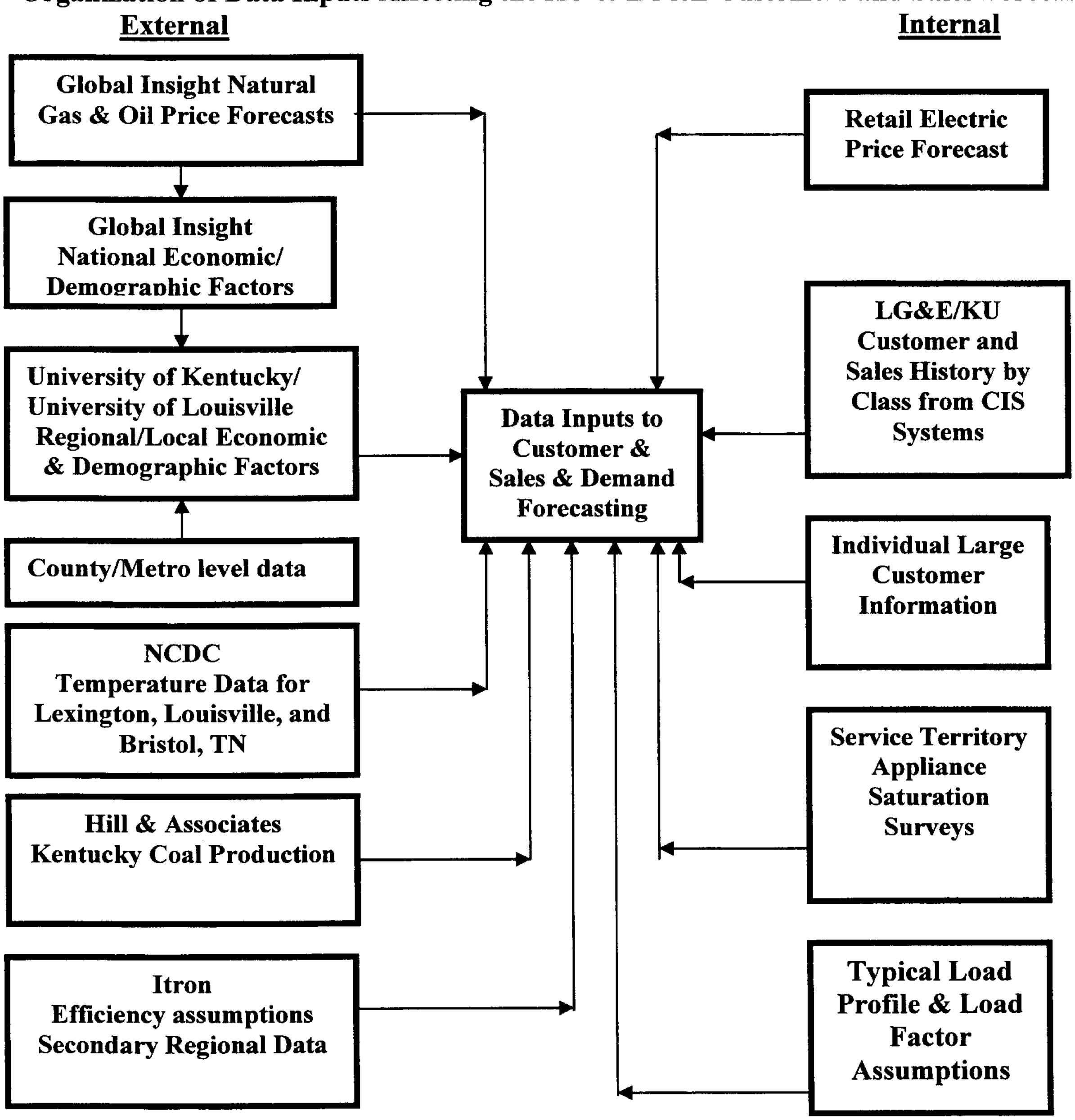
A more detailed description of the forecasting models, methods, and data used to develop the forecast is contained in Section 7 of this report and in Technical Appendices 1 and 2 of Volume II.

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, consumer prices, and industrial productivity are key determinants of the economic environment within which KU and LG&E must operate. Local influences are population, households, employment, personal income, weather, and the price of electricity. The utilities have contracted with Global Insight ("GI") to provide national macroeconomic data, while the Gatton Center for Business and Economic Research ("CBER") at the University of Kentucky ("UK") utilizes the GI data to generate local economic and demographic forecasts. Weather data is received from the National Climatic Data Center ("NCDC"), a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. New York Mercantile Exchange ("NYMEX") futures prices for oil and natural gas are utilized in rate class choice modeling in the KU forecast. A coal production forecast is obtained from Hill & Associates for use in modeling KU Mine Power tariff sales. Itron provides regional databases that support the modeling of appliance saturation and efficiency trends and customer choice. The retail electric price forecast, historical appliance saturations and efficiency trends, and load profile/load factor data for both utilities are determined internally.

Important information relative to growth prospects is also collected through discussions with the largest customers of KU and LG&E. These regular communications allow the Companies to directly adjust sales expectations given the first-hand knowledge of production outlook of these companies. Historical sales data on these customers and for the respective classes 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
Organization of Data Inputs Affecting the KU & LG&E Customers and Sales Forecasts



Key Assumptions

Following is a summary of key assumptions made in GI's Winter 2003 Long-Term Macro Forecast, used by the Companies as macroeconomic background for the energy sales forecast in the 2005 IRP. A copy of this forecast is attached as part of Technical Appendix 4, 'Supporting Documents,' in Volume II.

- *Trend Scenario*: GI assumed that the economy suffered no major mishaps or exogenous shocks. Economic output was forecast to grow smoothly, with actual output following potential output relatively closely.

- *Demographics*: The population projection in the GI trend scenario was consistent with the Census Bureau's 2000 "middle" projection for the U.S. population. Based on specific assumptions about immigration, fertility and mortality rates, U.S. population was forecast to achieve average annual growth of 0.9 percent from 2005 to 2019.

- *Energy*: Except for temporary spikes, GI forecasted that the average price of foreign oil would remain below $31 per barrel until 2009. In the longer term, GI projected that scarcity would begin to drive the real price of imported oil upward to $45 a barrel in 2019.

- *Output*: Growth in annual real U.S. Gross Domestic Product was projected to average 3.1 percent over the fifteen-year period from 2005 to 2019.

Economic and demographic assumptions were developed for each utility using the Kentucky State Econometric Model and the Companies' Service Territory Econometric Model ("STEM") to produce utility-specific forecast drivers. These assumptions are addressed in section 5.(3).

Resource Assessment and Acquisition Plan

In the planning decision-making process, the economics and practicality of supply-side and demand-side options are carefully examined to develop the IRP for meeting customers' expected needs. If, upon review, an alternative plan shows economic viability, a capacity expansion computer program is used to evaluate its operational characteristics and economics.

The Companies use New Energy Associates' Strategist® program for resource expansion studies. Strategist® contains several modules that can be executed in various ways to evaluate system resource expansion alternatives.

Two key assumptions and uncertainties associated with the development of the Companies' IRP are forecasted fuel prices and forecasted customer load requirements. As a part of the detailed resource assessment using Strategist®, sensitivity analyses were conducted on these variables.

Currently, three types of fuel are simulated in the resource optimization analysis: coal, oil, and natural gas. A major change in future oil, gas or coal prices can have a significant impact on the selection of new units and on the operation of existing units. Therefore, three fuel forecasts (Base, High, Low) are developed and analyzed as part of the development of the plan.

The load forecast (demand and energy forecast) is another significant factor influencing the Companies' resource plan. 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, a case in which system load growth exceeds expected growth, and a case in which system load growth is less than expected. The three load forecasts were analyzed as part of the IRP development.

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[1], and peak demand. On a Combined Company basis, native electric customers increased from 858,827 in 2000 to 903,834 in 2004, an average annual growth rate of 1.3 percent. Actual sales for KU and LG&E rose from 30,145 GWh in 2000 to 31,902 GWh in 2004, increasing at an average annual growth rate of 1.4 percent. On a weather-normalized basis, average sales growth was 1.6 percent over this period. Combined energy requirements grew from 32,058 GWh in 2000 to 33,796 GWh in 2004. Peak demand fluctuated over the 2000-2004 period. On an actual basis, peak demand fell from 6,317 MW in 2000 to 6,221 MW in 2001 only to increase to 6,513 MW in 2002. Further declines occurred in 2003 and 2004, which recorded peaks of 6,393 MW and 6,223 MW, respectively. However, on a weather-normalized basis, a slight increase in peak was recorded in 2003 over 2002 (6,448 MW vs. 6,429 MW) before declining to 6,362 MW in 2004. Because of the mild summer, weather-normalization added 139 MW to the 2004 peak.

1 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, 2000-2004

	2000	2001	2002	2003	2004
Customers	858,827	871,879	884,056	892,677	903,834
Sales (GWh)	30,145	29,856	31,369	30,999	31,902
Weather-Normalized Sales (GWh)	30,349	29,852	30,623	31,518	32,277
Energy Requirements (GWh) (actual)	32,058	31,749	33,254	32,778	33,796
Peak Demand (MW) [1]	6,317	6,221	6,513	6,393	6,223
Weather-Normalized Peak Demand (MW)	6,314	6,239	6,429	6,448	6,362

1 Includes impact of Interruptible and Curtailable loads

Combined Company Forecast

All forecasts of energy sales/requirements, peak demand, and use-per-customer assume normal weather – which is based on 20 years of average daily temperatures. Table 5.(3)-2 presents the forecast for Combined Company customer numbers, sales and energy requirements, together with forecast annual growth rates. From 2005 through 2009, Combined Company customers are forecast to grow at an average annual rate of 1.2 percent, while both sales and energy requirements are forecast to average 2.1 percent. By 2019, Combined Company customers are forecast to reach 1,062,741, averaging 1.1 percent growth over the full forecast horizon. The forecast calls for sales to reach 42,685 GWh in 2019, with annual growth averaging 2.0 percent.

Table 5.(3)-2
Combined Company: Forecast Customer Numbers, Sales, and Energy Requirements

Year	Combined Company Customers	% Growth in Customers	Combined Company Sales Forecast (GWh)	% Growth in Sales	Combined Company Requirements Forecast (GWh)
2005	909,469	0.6%[1]	32,490	0.7%[2]	34,468
2006	920,949	1.3%	33,133	2.0%	35,143
2007	932,352	1.2%	33,889	2.3%	35,954
2008	943,694	1.2%	34,651	2.2%	36,797
2009	955,020	1.2%	35,316	1.9%	37,462
2010	966,347	1.2%	35,957	1.8%	38,121
2011	977,264	1.1%	36,701	2.1%	38,931
2012	988,119	1.1%	37,373	1.8%	39,644
2013	998,879	1.1%	38,153	2.1%	40,493
2014	1,009,557	1.1%	38,898	2.0%	41,285
2015	1,020,186	1.1%	39,620	1.9%	42,033
2016	1,030,821	1.0%	40,294	1.7%	42,719
2017	1,041,457	1.0%	41,035	1.8%	43,524
2018	1,052,112	1.0%	41,870	2.0%	44,424
2019	1,062,741	1.0%	42,685	1.9%	45,306

1 Based on Combined Company customers of 903,834 in 2004
2 Based on Weather-normalized sales of 32,278 GWh in 2004

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 curtailments is forecast to grow from 6,696 MW in 2005 to 7,272 MW in 2009, a growth of 576 MW with an average annual growth rate of 2.1 percent. By 2019, Combined Company demand reaches 8,794 MW for a total increase from 2005 of 2,098 MW, with growth averaging 1.9 percent per year over the full forecast period. Combined Company curtailable load is estimated to be 100 MW for each summer period during the forecast. From

2005 through 2009, the winter peak increases by 495 MW for an average growth rate of 2.1 percent. By 2019, the winter peak is forecast to increase by 1,708 MW with growth averaging 1.9 percent per year. Curtailable load impacts in winter are 38 MW per year.

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

Year	Combined Company Summer Peak Demand (MW) [1]	Percent Growth	Year	Combined Company Winter Peak Demand (MW) [2]	Percent Growth
2005	6,696	5.3%[3]	2004/05	5,647	3.5%[3]
2006	6,811	1.7%	2005/06	5,754	1.9%
2007	6,951	2.1%	2006/07	5,896	2.5%
2008	7,125	2.5%	2007/08	5,974	1.3%
2009	7,272	2.1%	2008/09	6,142	2.8%
2010	7,383	1.5%	2009/10	6,223	1.3%
2011	7,556	2.3%	2010/11	6,388	2.7%
2012	7,662	1.4%	2011/12	6,500	1.8%
2013	7,859	2.6%	2012/13	6,574	1.1%
2014	7,993	1.7%	2013/14	6,768	3.0%
2015	8,159	2.1%	2014/15	6,890	1.8%
2016	8,292	1.6%	2015/16	6,972	1.2%
2017	8,430	1.7%	2016/17	7,134	2.3%
2018	8,587	1.9%	2017/18	7,287	2.1%
2019	8,794	2.4%	2018/19	7,355	0.9%

1 Includes impact of Combined Company Summer Interruptible and Curtailable load of 100 MW per year.

2 Includes impact of Combined Company Winter Interruptible and Curtailable load of 38 MW per year.

3 2005 growth based on normalized 2004 peaks of 6,362 MW and 5,454 MW for summer and winter, respectively.

Kentucky Utilities

History

From 2000 to 2004, KU billed sales grew at an average annual rate of 2.2 percent on a weather-normalized basis. Recent growth has been most pronounced in the Residential class (3.3 percent on average since 2000) followed by the Industrial (2.2 percent), Commercial (1.9 percent), and Municipal (1.5 percent) classes. Within the Residential category, the All-Electric ("FERS") class experienced the highest average growth rate of 4.1 percent on a weather-normalized basis. For the balance of KY Residential sales (the "RS" class), growth over that same period was 2.4 percent. Virginia retail sales averaged 1.8 percent growth since 2000. 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)

	2000	2001	2002	2003	2004
SYSTEM BILLED SALES:					
Recorded	18,612	18,618	19,488	19,470	20,074
Weather Normalized	18,735	18,639	19,114	19,702	20,458
SYSTEM USED SALES:					
Recorded	18,818	18,478	19,558	19,496	20,178
Weather Normalized	18,939	18,500	19,186	19,803	20,534
ENERGY REQUIREMENTS:					
Recorded	20,056	19,710	20,751	20,654	21,317
Weather Normalized	20,178	19,733	20,379	20,961	21,673
SALES BY CLASS (recorded):					
Residential Heating (FERS)	2,722	2,729	2,964	2,978	3,058
Residential Non-Heating (RS)	2,581	2,537	2,799	2,594	2,682
	--------	--------	--------	--------	--------
TOTAL RESIDENTIAL	5,303	5,266	5,763	5,572	5,740
Commercial	4,726	4,751	4,952	5,004	5,156
Industrial	5,983	5,648	5,933	6,027	6,312
Utility Use and Other	83	83	82	84	85
	--------	--------	--------	--------	--------
KENTUCKY Retail	16,095	15,748	16,730	16,687	17,293
Requirement Sales for Resale	1,843	1,842	1,926	1,903	1,959
	--------	--------	--------	--------	--------
TOTAL KENTUCKY	17,938	17,590	18,656	18,590	19,252
VIRGINIA Retail	880	888	902	906	926
TOTAL KU SALES	18,818	18,478	19,558	19,496	20,178
SYSTEM LOSSES	1,238	1,232	1,193	1,158	1,138
ENERGY REQUIREMENTS	20,056	19,710	20,751	20,654	21,317

KU Forecast

KU's long-term forecast drivers are produced by the STEM model. Key economic assumptions underlying the KU sales forecast are as follows.

Key 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 0.8 percent over the next five years and 0.9 percent nationally. This is a continuation of past trends where population growth in Kentucky has lagged the national average. Kentucky population was forecast to increase at an average rate of 0.8 percent over the fifteen-year forecast period through 2019. Furthermore, aging of the population leads to fewer people per household. The number of households was forecast to increase at a 1.3 percent annual rate for the next five years, and at a 1.1 percent rate over the fifteen-year forecast horizon.

- *Output:* Industrial value-added *(a measure of economic activity in this sector)* in the KU service territory was forecast to grow by 5.2 percent annually over the next five years. This rapid average rate of growth was particularly pronounced in 2005 and 2006 as the manufacturing industry was projected to continue to recover. Over the fifteen-year forecast horizon, Industrial value-added was forecast to increase at an average annual rate of 3.7 percent.

- *Employment:* Commercial employment was forecast to grow at 2.1 percent per year over the next five years and at a rate of 2.0 percent annually over the fifteen-year horizon.

- *Personal Income:* Real total personal income in the KU service territory was forecast to grow at a 3.4 percent average annual rate for the first five years, and at 3.6 percent annually over the fifteen-year horizon.

KU Customer Growth and Energy Sales

Total KU energy sales over the first five years (2005 to 2009) of the forecast are projected to rise at a 2.4 percent average annual rate. The forecast averages 2.0 percent growth over the fifteen-year forecast horizon. 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 2004 sales.

Kentucky Retail Residential sales are forecast to increase at a 1.7 percent annual rate from 2005 to 2009. 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 3.2 percent annual rate from 2005 to 2009, while Kentucky Retail Industrial sales are projected to average 2.6 percent growth. Significant growth by some of the larger Industrial customers creates a relatively strong medium-term growth outlook for the Industrial sector. A relatively unfavorable outlook for total coal production in Western Kentucky results in a forecast annual growth rate for energy sales under the Mine Power rate of 0.8 percent. Wholesale sales are forecast to grow at an average rate of 2.2 percent, generally in line with but slower than Kentucky Retail sales. Virginia sales are expected to increase only moderately, with 1.3 percent average growth.

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

Class	Percent of 2004 Sales	Percent Annual Growth 2005-2009	Percent Annual Growth 2005-2019
RETAIL	**90.4**	**2.4**	**2.1**
Kentucky	**85.9**	**2.5**	**2.1**
Residential	29.2	1.7	1.9
RS	13.6	0.5	0.9
FERS	15.5	2.8	2.7
Commercial	27.4	3.2	2.5
Industrial	26.7	2.4	1.8
General Industrial	16.1	3.5	2.8
Major Industrials	10.6	1.1	0.3
Coal Mining (MP, LMP)	2.0	0.8	0.6
Lighting (COLT, St. Lt.)	0.6	2.9	2.3
Virginia	**4.5**	**1.3**	**1.2**
WHOLESALE	**9.6**	**2.2**	**2.0**
TOTAL KU	**100.0**	**2.4**	**2.0**

Table 5.(3)-6 presents the 2005 KU forecast values for total customers and sales with their corresponding annual growth rates through 2019. Over the 2005-2009 period, sales are projected to grow at an average growth rate of 2.4 percent. Through the entire forecast horizon, annual growth is projected to be 2.0 percent.

Table 5.(3)-6
KU: Forecast Customer Numbers and Billed Sales (GWh)

Year	Customers	% Growth in Customers	Energy Sales Forecast (GWh)	% Growth in Energy Sales
2005	518,045	0.7%[1]	20,506	0.2[2]
2006	524,417	1.2%	20,945	2.1%
2007	530,617	1.2%	21,558	2.9%
2008	536,646	1.1%	22,102	2.5%
2009	542,598	1.1%	22,551	2.0%
2010	548,544	1.1%	22,968	1.8%
2011	554,169	1.0%	23,444	2.1%
2012	559,781	1.0%	23,868	1.8%
2013	565,346	1.0%	24,357	2.0%
2014	570,884	1.0%	24,829	1.9%
2015	576,422	1.0%	25,281	1.8%
2016	581,980	1.0%	25,697	1.6%
2017	587,541	1.0%	26,160	1.8%
2018	593,109	0.9%	26,687	2.0%
2019	598,697	0.9%	27,198	1.9%

[1] Based on 2004 Customers of 511,514 that excludes lighting

[2] Based on 2004 weather-normalized sales of 20,458 GWh

KU Peak Demand

KU's actual and weather-normalized peak demand over 2000-2004 are displayed in Table 5.(3)-7. On a weather-normalized basis and after curtailment, KU's summer and winter peaks in 2000 were 3,772[1] MW and 3,975 MW respectively. In 2004, the weather-normalized summer peak was 3,800 MW. The weather-normalized KU winter peaks have ranged from 3,975 MW in 2000 to 3,660 MW in 2002. In 2004, the winter peak was 3,771 MW.

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

	2000	2001	2002	2003	2004
SUMMER					
Recorded	3,775	3,699	3,899	3,810	3,744
Weather- Normalized	3.772	3,714	3,870	3,836	3,800
	99/00	**00/01**	**01/02**	**02/03**	**03/04**
WINTER					
Recorded	3,665	3,748	3,491	3,944	3,768
Weather- Normalized	3,975	3,886	3,660	3,930	3,771

KU Peak Demand Forecast

The KU summer peak demand is forecast to increase at an annual rate of 1.9 percent from 4,067 MW in 2005 to 5,393 MW in 2019, adding 1,326 MW over the period at an average of 95 MW per year. In the medium term, 2005 to 2009, the KU summer peak demand is forecast to increase from 4,067 MW to 4,472 MW (101 MW per year), which represents an average annual rate of 2.4 percent. For 2009 to 2019 the summer peak demand is forecast to increase at an

[1] Changes in weather-adjusted peaks reported in 2002 IRP are because of new normalization methodology.

average annual rate of 1.9 percent from 4,472 MW to 5,393 MW, adding 921 MW over the period at an average of 92 MW per year (Table 5.(3)-8).

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

Year	Energy Requirements (GWh)	Percent Growth	Summer Peak (MW) [2]	Percent Growth
2005	21,812	0.2%[1]	4,067	7.0% [3]
2006	22,273	2.1%	4,153	2.1%
2007	22,930	2.9%	4,275	2.9%
2008	23,530	2.6%	4,387	2.6%
2009	23,983	1.9%	4,472	1.9%
2010	24,399	1.7%	4,549	1.7%
2011	24,920	2.1%	4,646	2.1%
2012	25,376	1.8%	4,731	1.8%
2013	25,909	2.1%	4,830	2.1%
2014	26,420	2.0%	4,925	2.0%
2015	26,883	1.8%	5,012	1.8%
2016	27,298	1.5%	5,089	1.5%
2017	27,810	1.9%	5,184	1.9%
2018	28,377	2.0%	5,290	2.0%
2019	28,933	2.0%	5,393	1.9%

1 Based on 2004 weather-normalized value of 21,673 GWh
2 The peak demands include a reduction for Curtailable loads of 51 MW.
3 Based on 2004 weather normalized value of 3,800 MW

Louisville Gas & Electric

History

From 2000 to 2004, LG&E calendar sales grew at an average annual growth rate of about 1.0 percent on a weather-normalized basis. LG&E sales over this period are shown in Table 5.(3)-9.

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

	2000	2001	2002	2003	2004
SYSTEM BILLED SALES:					
Recorded	11,209	11,360	11,798	11,448	11,698
Weather Normalized	11,289	11,335	11,456	11,655	11,735
SYSTEM USED SALES:					
Recorded	11,329	11,377	11,810	11,503	11,724
Weather Normalized	11,409	11,352	11,436	11,715	11,744
ENERGY REQUIREMENTS:					
Recorded	12,003	12,038	12,503	12,123	12,532
Weather Normalized	12,083	12,013	12,129	12,335	12,552
SALES BY CLASS:					
Residential Heating	732	724	732	723	740
Residential Non-Heating	2,990	3,058	3,303	3,111	3,184
	---------	---------	---------	---------	---------
TOTAL RESIDENTIAL	3,722	3,782	4,036	3,835	3,924
General Service	1,364	1,388	1,404	1,379	1,395
Large Commercial	2,855	2,904	2,987	2,995	3,028
Large Power	3,318	3,253	3,314	3,225	3,308
Street Lighting	70	70	69	69	69
	---------	---------	---------	---------	---------
TOTAL LG&E SALES	11,329	11,397	11,810	11,503	11,724
SYSTEM LOSSES	674	641	692	620	756
ENERGY REQUIREMENTS	12,003	12,038	12,503	12,123	12,480

LG&E Forecast

The LG&E electric sales forecast is developed from a macroeconomic background produced by the STEM. Key economic assumptions underlying the LG&E sales forecast are as follows.

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 0.5 percent over the next five years and 0.6 percent over the fifteen-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 - 0.8 percent per year on average over the next five years and over the full fifteen-year forecast horizon.

- *Output:* Industrial Value-Added was forecast to increase at a 2.3 percent average annual rate over the next five years and over the fifteen-year horizon. However, a base of large, mature Industrial customers - accounting for a significant portion of Industrial load - was forecast to exhibit much slower growth in electric consumption in response to process efficiency initiatives and excess capacity.

- Personal *Income:* Real total personal income was forecast to increase at a 3.1 percent average annual rate over the first five years, and at a 3.5 percent growth rate over the fifteen-year forecast horizon.

LG&E Customer Growth and Energy Sales

Table 5.(3)-10 presents the five and fifteen-year average annual sales growth rates for each class along with their relative share of 2004 sales. Over the first five years of the energy forecast, sales growth by sector is forecast to be strongest in the Residential and Large Commercial sectors (2.2 and 2.0 percent respectively). Similarly, Small Commercial, Industrial and Street Lighting are projected to grow annually at 1.9, 0.3 and 0.4 percent respectively. Over the fifteen-year period, sales to the Residential sector exhibit the highest sustained growth at 2.3 percent, followed by Commercial (both Large and Small) at 1.9 percent. Industrial sales are projected to increase by 1.2 percent over the 2005-2019 period.

Table 5.(3)-10
LG&E: Sales Structure (2004) and Forecast Growth Rates by Class

Class	Percent of 2004 Sales	Average Annual Growth 2005-2009	Average Annual Growth 2005-2019
Residential	33.6	2.2	2.3
Small Commercial	11.9	1.9	1.9
Large Commercial	25.8	2.0	2.0
Large Industrial	28.1	0.3	1.2
Street Lighting	0.5	0.4	0.4
LG&E Total	100.0	1.6	1.9

Total LG&E energy sales over 2005-2009 are forecast to rise at a 1.6 percent annual average rate. The forecast averages 1.9 percent growth over the fifteen-year forecast horizon.

Table 5.(3)-11 presents the 2005 LG&E Forecast for total customers and sales with their corresponding annual growth rates through 2019. Sales are projected to increase by 1.3 percent

in the medium term (2005-2009) as national and state economic conditions creates strong short-term growth, with a gradual slowdown in the longer-term trend. Sales are projected to increase by 1.2 percent over the 2005-2019 forecast horizon.

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

Year	Customers	% Growth in Customers	Energy Sales Forecast (GWh)	% Growth in Energy Sales
2005	391,424	0.6%[1]	11,983	2.1%[2]
2006	396,532	1.3%	12,188	1.7%
2007	401,735	1.3%	12,330	1.2%
2008	407,048	1.3%	12,549	1.8%
2009	412,422	1.3%	12,765	1.7%
2010	417,803	1.3%	12,988	1.8%
2011	423,095	1.3%	13,258	2.1%
2012	428,338	1.2%	13,506	1.9%
2013	433,533	1.2%	13,796	2.2%
2014	438,673	1.2%	14,069	2.0%
2015	443,764	1.2%	14,339	1.9%
2016	448,841	1.1%	14,597	1.8%
2017	453,916	1.1%	14,874	1.9%
2018	459,003	1.1%	15,183	2.1%
2019	464,044	1.1%	15,488	2.0%

1 Based on 2004 customer number of 389,196

2 Based on 2004 weather-normalized sales of 11,735 MWh

LG&E Peak Demand

On a weather-normalized basis and after curtailment, LG&E peak demand in 2000 was 2,542 MW. As shown in Table 5.(3)-12, LG&E's weather-normalized summer peak demand in 2004 (after curtailment) was 2,562 MW.

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

	2000	2001	2002	2003	2004
SUMMER					
Recorded	2,542	2,522	2,623	2,583	2,485
Normalized	2,542	2,525	2,559	2,612	2,562
	99/00	**00/01**	**01/02**	**02/03**	**03/04**
WINTER					
Recorded	1,670	1,818	1,660	1,824	1,750
Normalized	1,724	1,838	1,691	1,818	1,683

LG&E Peak Demand Forecast

Table 5.(3)-13 presents the LG&E summer peak demand and energy requirements forecasts. The LG&E summer peak demand is forecast to increase at an annual growth rate of 1.9 percent from 2,629 MW in 2005 to 3,401 MW in 2019, adding 772 MW over the period at an average of 55 MW per year. Between 2005 and 2009, the summer peak demand is forecast to increase from 2,629 MW to 2,800 MW, at an annual rate of 1.6 percent, adding 171 MW over the four-year period at an average of 43 MW per year. For the 2009 to 2019 period, the summer peak demand is projected to increase at an annual rate of 2.0 percent from 2,800 MW to 3,401 MW, adding 601 MW over the period at an average of 60 MW per year.

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

Year	Energy Requirements (GWh)	Percent Growth	Summer Peak (MW)	Percent Growth
2005	12,657	1.3%[1]	2,629	2.6%[2]
2006	12,870	1.7%	2,673	1.7%
2007	13,024	1.2%	2,705	1.2%
2008	13,266	1.9%	2,756	1.9%
2009	13,478	1.6%	2,800	1.6%
2010	13,722	1.8%	2,850	1.8%
2011	14,011	2.1%	2,910	2.1%
2012	14,269	1.8%	2,964	1.9%
2013	14,584	2.2%	3,029	2.2%
2014	14,865	1.9%	3,088	1.9%
2015	15,151	1.9%	3,147	1.9%
2016	15,421	1.8%	3,203	1.8%
2017	15,713	1.9%	3,264	1.9%
2018	16,047	2.1%	3,333	2.1%
2019	16,374	2.0%	3,401	2.0%

1 Based on 2004 Energy Requirements of 12,500 GWh

2 Based on a weather-normalized 2004 summer peak of 2,562 MW

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 Resource Acquisitions

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 12% to 14% 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%. 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, *2005 Optimal Expansion Plan Analysis* (January 2005) contained in Volume III, Technical Appendix. The in-service years for the units shown assume the Companies' Base Load Forecast.

Table 5.(4)
Recommended 2005 Integrated Resource Plan

Year	Resource
2005	1.9 MW New DSM Initiatives
2006	4.9 MW New DSM Initiatives (cumulative totals)
2007	8.8 MW New DSM Initiatives (cumulative totals)
2008	13.4 MW New DSM Initiatives (cumulative totals)
2009	18.5 MW New DSM Initiatives (cumulative totals)
2010	549 MW (75% of 732 MW) Trimble County Unit 2 Supercritical Coal 23.7 MW New DSM Initiatives (cumulative totals)
2011	28.8 MW New DSM Initiatives (cumulative totals)
2012	
2013	148 MW Greenfield CT Unit 1
2014	WV Hydro Purchase Power Agreement
2015	148 MW Greenfield CT Unit 2 148 MW Greenfield CT Unit 3
2016	148 MW Greenfield CT Unit 4
2017	148 MW Greenfield CT Unit 5
2018	148 MW Greenfield CT Unit 6
2019	750 MW Greenfield Supercritical Coal Unit

Note: Unit Ratings are Proposed Summer Net Ratings

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 detailed resource planning computer models included the following supply-side options:

Supercritical Pulverized Coal unit at Trimble County Station (TC2)
WV Hydro Purchase Power Agreement ("PPA")
Supercritical Pulverized Coal, High Sulfur – 750 MW
Run of River-Ohio Falls Expansion (Units 9 and 10)
Combustion Turbines at a Greenfield Site
Combined Cycle Combustion Turbine (Un-Phased)

Along with these supply-side options, DSM programs are included in the integrated analysis. The optimal Integrated Resource Plan recommends the construction of a second coal unit at Trimble County, six Greenfield combustion turbines, the Purchase Power Agreement ("PPA") with W.V. Hydro, Inc., and one supercritical Greenfield coal unit. Also, there is the implementation of five new DSM programs which ramp up to a combined amount of 28.8 MW annually in 2011.

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 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 Hydro generating station. This evaluation has considered several economic options and continues to be an ongoing process.

Currently, the Ohio Falls Station has a 30-year operational license granted by the Federal Energy Regulatory Commission ("FERC") which will expire November 10, 2005. LG&E filed an Application for License Renewal with FERC on October 7, 2003. The relicensing process is underway with the current relicensing schedule anticipating a FERC decision in October 2005. On March 3, 2005, LG&E officially requested that the new license from FERC have a term of 40 years.

Ohio Falls has been in service since the 1920's with no significant rehabilitation efforts having taken place. A rehabilitation project to be implemented in three phases over a number of years began in 2001 with Phase 1 and Phase 2 now complete. Phase 3 entails the most significant scope of work including the rehabilitation of the turbine/generator units. Subject to FERC approval, Phase 3 of the rehabilitation will take place during the low water season in the latter six months of each year beginning in 2005. Current plans call for one unit to be repaired each year thereafter until all eight units are complete in 2012. This rehabilitation will increase the expected capacity output of the Ohio Falls Station to 64 MW from the current planned value (time of summer peak) of 48 MW and provide a potential for 187 GWh of additional annual energy production.

The Companies continually evaluate resources available to meet load obligations, including the options at the Ohio Falls station. Current plans to rehabilitate all eight units beginning with one unit will be continually evaluated as more detailed rehabilitation estimates become available and as the Companies learn from the actual condition of the units as the rehabilitation progresses one unit at a time. Further discussion is contained in Section 6.

Demand Side Management

The plan described in Table 5.(4) includes the implementation of 5 new programs, labeled collectively as New DSM Initiatives. Additional detail on the DSM alternative in the plan is contained in the report titled *Screening of Demand-Side Management (DSM) Options* (April 2005) contained in Volume III, Technical Appendix.

Non-Utility Generation

The plan described in Table 5.(4) includes some non-utility generation. On April 1, 2003 the Companies sent out a Request for Proposals ("RFP") in conjunction with Trimble County Unit 2 ("TC2") supply alternatives. One of these proposals was a renewable resource from W.V. Hydro, Inc. with a Purchase Power Agreement ("PPA"). Their most current offer dated October 14, 2004 consists of three 80 MW hydroelectric projects based on conventional hydro technology. The average summer output during the peak month is 181 MW. Pursuing this PPA to commence in 2013 after construction of TC2 lowers the overall revenue requirements. On occasion, the Companies receive inquiries from Independent Power Producers ("IPPs") and will continue to evaluate all bid proposals received with the goal of determining the least cost generation resources for meeting the needs of customers.

Location of Exempt Wholesale Generators ("EWGs") near or within the Companies' service territory may continue as the deregulated wholesale power marketplace evolves. The Companies anticipate receiving offers on occasion from EWG's to supply capacity needs and thus will include EWG's in any Requests for Proposals for purchased power that may be issued by the Companies in the future.

New Power Plants

The plan described in Table 5.(4) calls for Trimble County Unit 2, six new Greenfield combustion turbines and one Greenfield supercritical high sulfur coal unit. Clearly, new power plants are the most significant component 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 Projects.*

Bulk Power Purchase and Sales and Interchange

The Companies have purchase power arrangements with Owensboro Municipal Utilities ("OMU"), Ohio Valley Electric Corporation ("OVEC") and Electric Energy, Inc. ("EEInc.") 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 megawatts). For 2005, the Companies expect to receive 196 megawatts of capacity from OMU. For each year after 2005, the expected capacity available to KU is projected to decrease due to the increases in OMU's customer load.

On May 11, 2004 the City of Owensboro, Kentucky and Owensboro Municipal Utilities filed suit against Kentucky Utilities Company in Daviess County, Kentucky 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. Kentucky Utilities 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.

OVEC was formed for the purpose of providing electric power requirements projected for the uranium enrichment complex being built near Portsmouth, Ohio. However, beginning August 31, 2001, the power and energy from these plants was released from the original purpose and became available to the sponsoring companies. The Companies currently have access to 9.5% of the capacity and energy, which is approximately 225 MW of the installed capacity or approximately 209 MW reliably during the summer peak and varying capacity during the remaining months due to unit maintenance schedules. However, the Inter-Company Power Agreement ("ICPA") was renewed in 2004 and the Companies combined sponsorship will be 8.13% beginning in April 2006. Further details about OVEC and the Companies' sponsorship are contained in Section 6.

The EEInc. Power Supply Agreement ("PSA") expires December 31, 2005. Because KU has an ownership interest of only 20 percent while Ameren has an ownership interest of 80 percent, the disposition of the PSA after the expiration date is not certain at this time. For the purpose of this analysis, the Companies assume that the PSA will be extended in its current form for the entire study period. The PSA permits KU to take its 20% share in the output of six coal-fired, baseload units with combined capacity of approximately 1,000 megawatts. The Companies continue to schedule their 20 percent contract right to the 200 megawatts from EEInc.

5.(5) Steps to be taken during the next three (3) years to implement the plan;

As part of implementing the plan over the next three years, the Companies have submitted an application to the Commission for appropriate certificates for the installation of the second coal-fired unit at Trimble County (Case No. 2004-00507). However, the Companies currently do not have the Certificate of Public Convenience and Necessity ("CCN") from the Commission. Once certification is received, and once approvals for other state agencies are secured as applicable, construction will begin on this unit. Additional measures that Demand Side Management ("DSM") will be taking are outlined below.

Demand-Side Management

The DSM alternatives included in the 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 program and the expected lost revenue for the program.

As a final step, a Request for Proposal ("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 program.

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 2005 IRP, these scenarios were based on probabilistic simulation of the historical volatility exhibited by each utility's weather-normalized year-over-year sales trend (see KU or LG&E Technical Appendices in Volume II for a complete description).

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, High and Low Energy Requirements Forecast (GWh)

Year	Base Energy Requirements	High Energy Requirements	Low Energy Requirements
2005	34,468	34,731	34,087
2006	35,143	35,582	34,579
2007	35,954	36,589	35,180
2008	36,797	37,637	35,805
2009	37,462	38,485	36,283
2010	38,121	39,325	36,763
2011	38,931	40,341	37,352
2012	39,644	41,246	37,875
2013	40,493	42,309	38,489
2014	41,285	43,317	39,072
2015	42,033	44,269	39,613
2016	42,719	45,146	40,108
2017	43,524	46,163	40,698
2018	44,424	47,294	41,350
2019	45,306	48,402	41,991

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

Year	Base Peak	High Peak	Low Peak
2005	6,696	6,748	6,623
2006	6,811	6,898	6,703
2007	6,951	7,074	6,803
2008	7,125	7,288	6,935
2009	7,272	7,471	7,044
2010	7,383	7,618	7,122
2011	7,556	7,831	7,250
2012	7,662	7,974	7,321
2013	7,859	8,215	7,470
2014	7,993	8,390	7,565
2015	8,159	8,597	7,689
2016	8,292	8,768	7,785
2017	8,430	8,947	7,882
2018	8,587	9,148	7,991
2019	8,794	9,402	8,149

Purchased Power

The unprecedented purchased power price volatility, which began in 1998, has not been repeated 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 which reached $239/MWh in 1997 and then rose as high as $7,500/MWh in 1998 have steadily dropped to $2000/MWh in 1999, and as low as $60/MWh in 2002. However, recent trends in the last two years have contributed to an increase in next day prices in 2003 and 2004 to as high as $129/MWh. These market price trends (which are difficult to predict) are significant relative to the Companies' need to address native load growth and expansion in a cost-effective manner.

The forward prices in the market for purchased power change frequently. Such a change 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 DSM alternatives included in the 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

The generating units in the Companies fleet continue to age. The two oldest steam generating units in the system are Tyrone Units 1 and 2. Each of these is over fifty 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, otherwise referred to by the Companies as Group 3 units.

Having operated past their design lives, units run a greater risk of catastrophic failure than other units. As evaluations indicated such, Green River Units 1 and 2 were operationally retired December 31, 2003 for economic reasons. Further details of their retirement are described in Section 6 of this IRP.

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. This plan has a sensitivity done with these units retiring in 2010, the first year that Clean Air Interstate Rule ("CAIR") goes into effect. This is covered in more details in the *2005 Optimal Expansion Plan Analysis* (January 2005) contained in Volume III, Technical Appendix. Any decision to retire generation would change the future capacity needs.

Table 5.(6)-4
Aging Units

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2005)
Steam	Tyrone	1	27	1947	58
Steam	Tyrone	2	31	1948	57
CT	Waterside	7	11	1964	41
CT	Waterside	8	11	1964	41
CT	Cane Run	11	14	1968	37
CT	Paddy's Run	11	12	1968	37
CT	Paddy's Run	12	23	1968	37
CT	Zorn	1	14	1969	36
CT	Haefling	1,2,3	36	1970	35

Midwest Independent Transmission System Operator

The Midwest Independent Transmission System Operator Inc. ("MISO") is in the process of developing transmission and generation resource adequacy proposals. As members of the MISO, the Companies continue to closely monitor and participate. The impact of these MISO initiatives is difficult to gauge at this time.

As described in Section 6, MISO Day 2 markets, i.e. Day Ahead and Real-Time energy markets with LMPs, will impact the very nature of the wholesale power market in the Midwest. The expected costs and benefits associated with the Companies' membership in MISO are the subject of a Commission investigation in Case No. 2003-00266 and are not explicitly incorporated as a significant change to the 2005 IRP relative to the 2002 IRP due to the on-going nature of that proceeding.

In December 2004, the Companies notified MISO of their intent to withdraw from MISO at the end of 2005. The outcome of the aforementioned proceeding and any subsequent proceedings related to the Companies' membership in MISO may ultimately impact the analyses included in the 2005 IRP. It is not possible to detail those potential impacts at this time.