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

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## VOLUME I

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# 4. FORMAT

## 4.(1) Organization

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

The format of the report is outlined below.

I. Volume I

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

II. Volume II. Technical Appendix

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

III. Volume III. Technical Appendix

1) Recommendations in PSC Staff Report on the Last IRP Filing
2) 2014 Reserve Margin Study
3) 2014 Resource Assessment
4) Appendix to Sections 8 and 9 – Scenario Data
5) Transmission Information

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

Chris Balmer, Director Transmission Strategy and Planning

Kyle Burns, Manager Generation Engineering

Michael Hornung, Manager Energy Efficiency Planning and Development

David Huff, Director Customer Energy Efficiency, Smart Grid Strategy

Tom Jessee, VP Transmission

Delyn Kilpack, Manager Transmission Strategy and Planning

Gregory Lawson, Manager Sales Analysis and Forecasting

Rick E. Lovekamp, Manager Regulatory Affairs

John Malloy, VP Customer Services

John Moffett, Manager Research and Development

Steve Noland, Manager Environmental Air Section

Gary Revlett, Director Environmental Affairs

Eileen Saunders, Director Generation Services

Charles R. Schram, Director Energy Planning, Analysis and Forecasting

Michael Sebourn, Manager Economic Analysis

David S. Sinclair, VP Energy Supply and Analysis

Edwin R. Staton, VP State Regulation and Rates

Allyson Sturgeon, Senior Corporate Attorney

John Voyles, VP Transmission/Generation Services

Stuart Wilson, Manager Generation Planning

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# 5. PLAN SUMMARY

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

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") are investor-owned public utilities supplying electricity and natural gas to customers primarily in Kentucky. Both LG&E and KU are subsidiaries of LG&E and KU Energy LLC ("LKE"), which is a subsidiary of PPL Corporation (NYSE: PPL). As the owners and operators of interconnected electric generation, transmission, and distribution facilities, LG&E and KU (the "Companies") achieve economic benefits through operation as a single interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities.

The mandate for the Companies' Integrated Resource Plan ("IRP") is to meet future energy requirements within their service territories at the lowest reasonable cost consistent with reliable supply. Serving more than 940,000 electricity customers via an electric transmission and distribution network consisting of more than 27,000 miles of lines and conduit, the Companies have a joint net summer generation capacity of 7,906 megawatts ("MW") as shown in Table 5.(1)-1. Based in Lexington, KU serves 543,000 electric customers in an area that covers approximately 4,800 non-contiguous square miles and includes 77 counties in Kentucky, five counties in southwest Virginia, and five customers in Tennessee.[1] KU also sells wholesale electricity for resale to twelve municipalities in Kentucky. LG&E, an electric and natural gas

[1] The five counties in southwest Virginia are serviced by Old Dominion Power Company ("ODP"), the name under which KU operates in Virginia.

utility, serves 321,000 natural gas and 397,000 electric customers in an area that covers approximately 1,300 square miles and includes Louisville and sixteen surrounding counties.

The Companies’ goals are to provide safe, adequate and reliable service to their customers at the lowest reasonable cost, and to achieve equitable cost allocation between customers based on the costs of providing service. Each of the Companies' retail customers is included in one of 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, the manufacture of electrical and other machinery, and the manufacture of paper and paper products.

The Companies' power generating system consists of eighteen coal-fired units, eleven hydro units, and twenty simple-cycle combustion turbines (“SCCTs”) that are predominantly gas-fired.[2] The coal-fired units are located at the E.W. Brown, Cane Run, Ghent, Green River, Mill Creek, and Trimble County generating stations. Several of these stations also contain SCCTs to supplement the system during peak periods. SCCTs are located at the E.W. Brown, Cane Run, Trimble County, Paddy’s Run, Zorn, and Haefling generation stations. The Companies’ hydroelectric facilities are located at the Dix Dam and Ohio Falls stations. The generation portfolio for KU and LG&E is summarized by fuel type in Table 5.(1)-1. (See Table 8.(3)(b) in Section 8 for a detailed listing of generating units.)

[2] Several of the Companies’ SCCTs have duel fuel capabilities and can be fired with oil.

**Table 5.(1)-1**
**Generating Unit Totals**

| | 2014 Summer Net Capacity (MW) | 2014/15 Winter Net Capacity (MW) |
|---|---|---|
| **KU** | | |
| Coal | 3,220 | 3,251 |
| Gas | 1,442 | 1,608 |
| Hydro | 24 | 24 |
| **Total KU** | **4,685** | **4,883** |
| | | |
| **LG&E** | | |
| Coal | 2,523 | 2,537 |
| Gas | 644 | 725 |
| Hydro | 54 | 35 |
| **Total LG&E** | **3,221** | **3,297** |
| | | |
| **Total** | | |
| Coal | 5,742 | 5,787 |
| Gas | 2,086 | 2,333 |
| Hydro | 78 | 59 |
| **Total** | **7,906** | **8,180** |

The Companies' net summer generating capacity in 2014 is planned to be 7,906 MW. In addition to company-owned resources, the Companies have purchase agreements in place with Ohio Valley Electric Corporation ("OVEC"). In total, the Companies currently receive 8.13 percent of the OVEC capacity and energy for an additional 172 MW at the time of summer peak. Further description of the OVEC sponsorship is contained in Section 5.(4).

The Companies' highest combined system peak demand of 7,175 MW occurred on August 4, 2010, at hour ending 15:00 EST. At that time, LG&E experienced its highest peak demand of 2,852 MW. The Companies' highest combined system *winter* peak demand of 7,114 MW occurred on January 6, 2014, at hour ending 21:00 EST. KU experienced its highest peak demand of 5,068 MW during this hour.

In 2011, the Companies announced plans to retire approximately 800 MW of coal-fired capacity to comply with the U.S. EPA's National Ambient Air Quality Standards and Mercury and Air Toxics Standards. In February 2013, the Companies retired Tyrone 3; the IRP assumes the three Cane Run and two Green River coal units will be retired in 2015. To offset this loss of energy and capacity, the Companies proposed to construct a 640 MW 2x1 natural gas combined cycle ("NGCC") unit at their Cane Run site to be online in 2015 ("Cane Run 7" or "CR7") and purchase the existing LS Power Bluegrass facility in LaGrange, Kentucky (495 MW of simple-cycle combustion turbines ("SCCTs")).

The construction of Cane Run 7 is underway and on schedule. However, the Companies were unable to purchase the Bluegrass facility after receiving an unfavorable Federal Energy Regulatory Commission ("FERC") ruling in May 2012. After preparing a new load forecast in the summer of 2012, it was confirmed that without the Bluegrass facility, additional resources would be required as early as 2015 in order to reliably serve customers' capacity and energy needs.

To meet the long-term need for capacity and energy, the Companies issued an RFP in September 2012. Based on the analysis of RFP responses, self-build alternatives, and DSM programs, the Companies submitted an application for Certificates of Public Convenience and Necessity ("CPCN") in January 2014 to the Kentucky Public Service Commission for the construction of (a) a solar photovoltaic ("PV") facility at the E.W. Brown station in 2016 and (b) a NGCC unit at the Green River station in 2018.[3] The CPCN does not address the Companies' need for capacity and energy in 2015 through 2017. The Companies plan to address this need by exploring all available options, including (but not limited to) alternatives from parties that provided responses to the September 2012 RFP and extending the life of Green River units 3 and 4.[4] Cane Run 7, the short-term capacity additions in 2015 through 2017, and the proposed solar PV and NGCC facilities complete the Companies' expansion plan through 2018. The purpose of the IRP is to update the Companies' forecasted expansion plan beyond 2018.

The Companies' integrated resource planning process consists of the following activities: 1) assessment of demand-side options, 2) development of a robust forecast of system energy requirements and peak demands, 3) determination of a target reserve margin criterion, 4) adequacy assessment of existing generating units and purchase power agreements, and 5) assessment of supply-side options. The impact of the Companies' demand-side management programs are reflected in the forecast of energy requirements and peak demands. Then, the

[3] See Case No. 2014-00002

[4] Based on compliance requirements and date in the MATS regulations, Green River units 3 and 4 cannot be operated after April of 2015 without additional emission controls. The regulations do provide for extensions of 1 or 2 years from that date, if granted by the permitting authority. At this time, the Companies have not sought extension of the compliance date, but are analyzing this option.

Companies' resource assessment combines key elements of the remaining activities into a plan for meeting future energy requirements at the lowest reasonable cost.

The Companies continually evaluate their resource needs. The IRP represents a snapshot of this ongoing resource planning process using current business assumptions and assessment of risks. Because the planning process is constantly evolving, the Companies' least-cost expansion plan may be revised as conditions change and as new information becomes available. Even though the IRP represents the Companies' analysis of the best options to meet customer needs at this given point in time, this plan is reviewed, re-evaluated, and assessed against other market available alternatives prior to commitment and implementation.

The Companies considered the Commission Staff Report on the 2011 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company dated March 2013 (Case No. 2011-00140) 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. Decisions regarding 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 for 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 utilized in developing the energy and demand forecast for the 2014 IRP.

***Demand and Energy Forecast - Models and Methods***

The Companies' forecasting approach is based on econometric modeling of energy sales by customer class, but also incorporates specific intelligence on the prospective energy requirements of the utility's largest customers. Econometric modeling captures the (observed) statistical relationship between energy consumption – the dependent variable – and one or more independent explanatory variables such as the number of households or the level of economic activity in the service territory. Forecasts of electricity sales are then derived from a projection of the independent variable(s). The model-based forecasts are then adjusted to reflect the impact of the Companies' demand side management programs on demand and energy. Further discussion of the Companies' demand side management evaluation process and specific programs is provided below and in Section 8.(3)(e).

This widely-accepted approach can readily accommodate the influences of national, regional and local (service territory) drivers of electricity sales. This approach may be applied to forecast the number of customers, 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 2013 was: 87 percent Kentucky-retail; 4 percent Virginia-retail; and 9 percent wholesale. Within each jurisdiction, the forecast typically distinguishes several classes of customers including residential, commercial, and industrial.

The econometric models used to produce the forecast passed two critical tests. First, the explanatory variables of the models were theoretically appropriate and have been widely used in electricity sales 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 to be theoretically and empirically robust to explain the historical behavior of the Companies' customers.

Sales to several of the Companies' 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 utilization 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 – that recognize expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

Once complete, the Companies' energy forecasts are converted from a billed to calendar basis and associated with class-specific load profiles to create hourly sales forecasts. These hourly sales forecast are then adjusted for company uses and losses to produce a forecast of hourly energy requirements.

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

***Demand and Energy Forecast – Data***

Data inputs to the forecasting process come from a variety of external and internal sources. The national outlook for U.S Gross Domestic Product ("GDP"), industrial production and consumer prices are key macro-level variables that establish the broad market environment within which the Companies 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 (IHS Global Insight).

Weather data for each service territory is provided by the National Climatic Data Center ("NCDC"), a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. Itron provides regional databases with information from the Energy Information Administration ("EIA") that supports the modeling of appliance saturation and efficiency trends. 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 the Companies are forecast based on information provided by these customers to the Companies. Historical sales data for these customers and for the respective class forecasts are obtained via extracts from the Companies' Customer Care System ("CCS"). Figure 5.(2)-1 illustrates the external and internal data sources used to derive the Companies' forecasts.

**Figure 5.(2)-1**
**Data Inputs to the Companies' Customer, Sales, and Demand Forecasts**

| External | Internal |
|---|---|
| IHS Global Insight<br>National Economic/ Demographic Factors | Retail Electric Price Forecast |
| IHS Global Insight<br>County & State Economic/ | The Companies' Customer and Sales History by Rate Class from CCS |
| NCDC<br>Temperature Data for Lexington, Louisville, and Bristol, TN | Individual Large Customer Information |
| Itron/EIA<br>Appliance Efficiency & Saturation | Service Territory Appliance Saturation Surveys |
| | Demand-Side Management Programs |
| | Class-Specific Load Profiles from Load Research Data & Load Factor Assumptions |

***Demand and Energy Forecast – Key Assumptions***

To create reliable forecasts of energy consumption, the Companies must account for the socio-economic conditions surrounding the forecast period. The Companies subscribe to services provided by IHS Global Insight that include estimates of current economic conditions and predictions of future conditions. IHS Global Insight's 2013 Long-Term Macro Forecast and the Population and Household Forecast were considered in developing the 2014 IRP demand and energy forecast. Copies of the economic and demographic forecasts are attached as part of Technical Appendix, 'Supporting Documents,' in Volume II.

- *U.S. Macro-Economic Summary*

  The Companies utilized IHS Global Insight's baseline "trend scenario" to develop their demand and energy forecast. The baseline is a projection that assumes no recessions or booms between now and 2028. The projection is best described as depicting the mean of all possible paths the economy could follow, absent any major disruptions such as oil price shocks or major changes in policy.

  Growth in annual real U.S. GDP is forecasted to average 2.5 percent from 2013 to 2042, 0.2 percent below the 30-year historical average. This slower growth is driven by slower growth in the labor force with retirement of Baby Boomers. Real personal disposable income is forecasted to rise 2.4 percent annually over the next 30 years, 0.3 percent lower than the 30-year historical average. The baseline scenario demographics are built on Census Bureau data and forecast that the U.S. population will expand at an annual rate of 0.7 percent from 2013 to 2043.

- *Kentucky*

Kentucky's real GSP is forecast to grow at 2.0 percent annually over the next 30 years, slightly lower than the 2.2 percent annual growth from 1990-2007 (prior to the 2008 recession) 1990[5]. Kentucky real personal disposable income is forecasted to rise 2.2 percent annually over the next 30 years, slightly below the 30-year historical average of 2.4 percent. The Kentucky population is forecasted to expand at an annual rate of 0.5 percent from 2014 to 2028, lower than the prior 15-year growth rate of 0.6 percent. See Section 6 for additional comparisons of current economic inputs to those used in the prior 2011 IRP.

***Demand-Side Management Screening***

Prior to their inclusion in the load forecast for demand and energy, Demand-Side Management programs are evaluated to ensure their cost-effectiveness on multiple measures, including comparison to the avoided cost of new capacity. More detailed information on specific Demand-Side Management programs is provided in Section 8.(3)(e)(3).

The benefit/cost calculations for demand-side management programs were performed using DSMore, a PC-based software package developed by Integral Analytics, Inc. DSMore provides robust analytics surrounding weather and market conditions and a transparent platform to understand the underlying calculations associated with the benefit/cost tests. The Companies calculated the four benefit/cost tests contained in the California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects ("Manual").[6] These tests and their Manual definitions are:

[5] Kentucky RGSP data is available starting in 1990.

[6] The Manual is available online at: http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

- **The Participant Test:** The Participant Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.[7]

- **The Ratepayer Impact Measurement Test:** The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates and bills will go down if the change in revenue from the program is greater than the change in utility costs. Rates and bills will go up if revenue collected after program implementation is less than the total cost incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.[8]

- **The Total Resource Cost Test:** The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).[9]

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[7] Manual at 8.

[8] Manual at 13.

[9] Manual at 18.

- **The Program Administrator Cost Test (or "Utility Cost Test"):** The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC [Total Resource Cost] benefits. Costs are defined more narrowly.[10]

**Resource Assessment**

***Resource Assessment – Models, Methods, and Key Input Assumptions***

Both the economics and practicality of supply-side options are carefully examined to develop an IRP for reliably meeting future energy requirements at the lowest reasonable cost. The Companies' resource assessment was completed in two parts. First, the Companies performed a screening analysis of more than 50 generation technology options to determine a subset of the most competitive options. Then, this subset of generation technology options was incorporated into a detailed expansion planning analysis to determine the optimal expansion plans beyond 2018.

In the screening analysis, the levelized cost of the technology options was calculated at various levels of utilization. In addition to the level of utilization (i.e., capacity factor), the levelized cost of each technology option is impacted by the uncertainty in capital cost, fuel cost, unit efficiency, and $CO_2$ emissions. As a result, the technology options were evaluated over three capital cost scenarios, three heat rate scenarios, three fuel scenarios, two $CO_2$ scenarios, and ten capacity factors for a total of 540 cases. Given the uncertainty in REC prices and the availability of investment tax credits ("ITC") for renewable technologies, two iterations of 540 cases were evaluated:

[10] Manual at 23.

- No ITC or RECs: This iteration did not include an ITC for renewable technologies or wind and solar RECs.
- 10 percent ITC and RECs: This iteration incorporated a 10 percent ITC and current REC market prices for solar and wind technologies.

The Companies continue to use the Strategist® program for their detailed expansion planning analyses. Strategist® is a proprietary computer model developed by Ventyx, which integrates the supply-side and demand-side inputs to produce a ranked number of plans that meet the prescribed environmental compliance and reliability criteria. The detailed expansion planning analysis assumed that existing units would remain economic to operate provided their capacity factors do not consistently fall below 10 percent. A complete summary of the models and methodologies utilized in the resource assessment is included in the report titled *2014 Resource Assessment* contained in Volume III, Technical Appendix.

The list of generation technology types considered in the resource assessment includes natural gas, coal-fired, waste to energy, energy storage, renewable, and nuclear technologies. The cost and performance characteristics of these technology options were estimated by Burns & McDonnell, an engineering consulting firm. More information regarding these technology options is contained in the report titled *2014 Resource Assessment* contained in Volume III, Technical Appendix.

***Resource Assessment – Key Uncertainties***

The Companies evaluate long-term resource decisions under a number of possible futures to ensure that customers' energy needs are reliably met at the lowest reasonable cost. While there are a number of uncertainties that could have some impact on the Companies' resource decisions, the uncertainties in native load (demand and energy), natural gas prices, and greenhouse gas ("GHG") regulations are the most important to consider when evaluating long-term generating resources.

The only reason for the Companies to acquire new supply-side or demand-side resources is to reliably meet customers' future energy needs at the lowest reasonable cost. Therefore, the forecast of customers' demand and energy needs has a significant impact on the Companies' expansion plan. As discussed previously, the Companies utilized the best information available to develop a reasonable long-term "Base" load forecast. As with any long-term forecast, the uncertainty associated with it tends to grow through time. Therefore, "High" and "Low" load forecasts were also developed which reflect the statistical uncertainty about the Base load forecast..

Because of the Environmental Protection Agency's ("EPA's") proposed New Source Performance Standards ("NSPS") for GHG, natural gas has become the fuel of choice for new fossil generation. An abundance of natural gas supply resulting from advancements in natural gas drilling technologies has put downward pressure on prices and greatly improved the economics of NGCC technology. On the other hand, the impending nationwide retirement of coal units and the shift to NGCC units will increase the demand for natural gas and put upward pressure on prices. Additional upside price risk is associated with the possibility of regulations limiting the extraction of shale gas. The price of natural gas could have a significant impact on the Companies' optimal expansion plan; lower natural gas prices would favor natural gas technology options, while higher natural gas prices would make renewable generation more competitive. To address this long-term natural gas price uncertainty, the resource assessment considered "Low," "Mid," and "High" natural gas price scenarios.

GHG regulation could have a significant impact on the Companies' optimal expansion plan by making renewable generation more competitive and potentially resulting in the economic retirement of existing units, which would accelerate the need for additional generating resources. Because the exact nature of future GHG regulations, should they occur, remains unknown, the Companies utilized two approaches to evaluate their potential impact. The first approach puts a price on each ton of $CO_2$ emitted; the second places a cap on $CO_2$ mass emissions.

The analysis considered "Mid" and "Zero" $CO_2$ price scenarios. The Mid $CO_2$ price scenario was prepared by Synapse Energy Economics, Inc., a consulting firm that does a significant amount of work for various environmental groups such as the Sierra Club and Natural Resources Defense Council. In the Mid $CO_2$ price scenario, $CO_2$ prices begin in 2020. Because future GHG regulation on existing units is by no means assured, a Zero $CO_2$ price scenario was analyzed assuming that there is never a price on future $CO_2$ emissions.

The second approach for evaluating the potential impact of GHG regulations places a cap on annual $CO_2$ mass emissions. In June 2013, the President released his Climate Action Plan which includes his intention to reduce $CO_2$ emissions from 2005 levels by 17 percent. For this reason, in the "CO2 mass emissions cap" scenario, annual $CO_2$ mass emissions for the Companies are limited to 29.4 million tons of $CO_2$ per year beginning in 2020.

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

**Combined Company**

***Combined Company Forecast***

Table 5.(3)-1 presents the Combined Company forecasts for the number of customers, sales, and energy requirements. The forecasts of sales and energy requirements reflect the impact of the Companies' demand-side management programs, as further detailed in Section

8.(3)(e). In addition, all forecasts of energy sales/requirements, peak demand, and use-per-customer assume normal weather – based on the 20-year period (through 2012) average of daily temperatures in each month.

From 2014 to 2018, the number of customers for the Combined Company is forecasted to grow at an annual rate of 0.8 percent. From 2014 through 2028, the number of customers is forecasted to grow at an annual rate of 0.6 percent. Combined Company sales and energy requirements are expected to grow at an annual rate of 0.7 percent from 2014 to 2028.

**Table 5.(3)-1**
**Combined Company: Forecasts of Customers , Sales, and Energy Requirements**

| Year | Combined Company Customers* | % Growth in Customers | Combined Company Sales Forecast (GWh)* | % Growth in Energy Sales | Combined Company Requirements Forecast (GWh)* | % Growth in Energy Requirements |
|---|---|---|---|---|---|---|
| **2013** | 936,208 | | 32,994 | | 34,874 | |
| **2014** | 947,671 | 1.2% | 33,679 | 2.1% | 35,716 | 2.4% |
| **2015** | 954,801 | 0.8% | 33,845 | 0.5% | 35,892 | 0.5% |
| **2016** | 962,243 | 0.8% | 34,093 | 0.7% | 36,153 | 0.7% |
| **2017** | 969,693 | 0.8% | 34,307 | 0.6% | 36,383 | 0.6% |
| **2018** | 977,123 | 0.8% | 34,594 | 0.8% | 36,684 | 0.8% |
| **2019** | 983,593 | 0.7% | 34,889 | 0.9% | 36,998 | 0.9% |
| **2020** | 989,345 | 0.6% | 35,134 | 0.7% | 37,260 | 0.7% |
| **2021** | 994,861 | 0.6% | 35,347 | 0.6% | 37,479 | 0.6% |
| **2022** | 999,513 | 0.5% | 35,554 | 0.6% | 37,704 | 0.6% |
| **2023** | 1,003,470 | 0.4% | 35,758 | 0.6% | 37,922 | 0.6% |
| **2024** | 1,007,731 | 0.4% | 36,054 | 0.8% | 38,235 | 0.8% |
| **2025** | 1,012,177 | 0.4% | 36,284 | 0.6% | 38,478 | 0.6% |
| **2026** | 1,016,718 | 0.4% | 36,522 | 0.7% | 38,731 | 0.7% |
| **2027** | 1,021,386 | 0.5% | 36,774 | 0.7% | 38,990 | 0.7% |
| **2028** | 1,026,103 | 0.5% | 37,038 | 0.7% | 39,279 | 0.7% |

*Number of customers in 2013 is an actual value. Sales and energy requirement values in 2013 are weather-normalized actual values. Sales and Energy Requirements have been reduced for DSM programs.

Table 5.(3)-2 presents the Combined Company forecast for summer and winter season peak demands. The Combined Company demand forecast reflects the coincident peak of both utilities (KU and LG&E); the individual company peaks are not necessarily coincident. The Combined Company peak demand is forecasted to grow from 6,972 MW in 2014 to 7,199 MW in 2018, an annual growth rate of 0.8 percent. By 2028, the Combined Company demand forecast reaches 7,766 MW. Over the full forecast period, the annual growth rate in Combined Company summer peak demand is 0.8 percent; the annual growth rate in Combined Company winter peak demand is 0.7 percent.

**Table 5.(3)-2**
**Combined Company Seasonal Peak Demand Forecast after DSM**

| Combined Company Summer Peak Demand | | | Combined Company Winter Peak Demand | | |
|---|---|---|---|---|---|
| **Year** | **MW*** | **Percent Growth** | **Year** | **MW** | **Percent Growth** |
| **2013** | 6,434 | | **2012/13** | 5,907 | |
| **2014** | 6,972 | 8.4% | **2013/14** | 5,977 | 1.2% |
| **2015** | 7,028 | 0.8% | **2014/15** | 6,022 | 0.7% |
| **2016** | 7,085 | 0.8% | **2015/16** | 6,091 | 1.2% |
| **2017** | 7,142 | 0.8% | **2016/17** | 6,112 | 0.3% |
| **2018** | 7,199 | 0.8% | **2017/18** | 6,141 | 0.5% |
| **2019** | 7,257 | 0.8% | **2018/19** | 6,193 | 0.9% |
| **2020** | 7,315 | 0.8% | **2019/20** | 6,235 | 0.7% |
| **2021** | 7,374 | 0.8% | **2020/21** | 6,318 | 1.3% |
| **2022** | 7,433 | 0.8% | **2021/22** | 6,337 | 0.3% |
| **2023** | 7,488 | 0.7% | **2022/23** | 6,369 | 0.5% |
| **2024** | 7,542 | 0.7% | **2023/24** | 6,398 | 0.5% |
| **2025** | 7,598 | 0.7% | **2024/25** | 6,436 | 0.6% |
| **2026** | 7,653 | 0.7% | **2025/26** | 6,494 | 0.9% |
| **2027** | 7,709 | 0.7% | **2026/27** | 6,565 | 1.1% |
| **2028** | 7,766 | 0.7% | **2027/28** | 6,595 | 0.4% |

* The 2013 actual summer peak occurred in September while forecasted peaks are assumed to occur in July/August as is typically the case.

**Kentucky Utilities Company**

***KU Customer Growth and Energy Sales***

Table 5.(3)-3 summarizes the five- and fifteen-year growth rates for each class of sales along with each class's relative share of 2013 sales.

KU's retail residential sales in Kentucky are forecasted to grow at a 0.7 percent annual rate from 2014 to 2018 and a 0.9 percent annual growth rate from 2014 to 2028. Residential sales growth is driven by the growth in the number of residential customers; residential use-per-customer is forecasted to grow only slightly over the forecast period. Retail commercial sales in Kentucky are forecast to increase at a 0.7 percent annual rate from 2014 to 2018. The KU Commercial class also contains some larger customers that are more industrial in nature. These customers result in a higher annual growth rate for the KU Commercial class than would otherwise be the case. Retail industrial sales in Kentucky are projected to grow at 0.6 percent annually. Growth by some of the larger industrial customers and customers in the automotive sector creates a modest medium-term growth outlook for the industrial sector. As the mining industry continues to struggle, KU's sales in Virginia are forecasted to grow at only 0.1 percent annually from 2014 to 2018.

Wholesale sales, as forecasted by the municipal customers, are forecasted to grow at an annual rate of 1.2 percent from 2014 to 2018 and at 1.0 percent from 2014 to 2028. This growth rate is higher than the overall KU growth rate. If wholesale sales grew at the rate of overall KU sales, this would result in a 8 MW reduction in the Companies' forecasted peak demand by 2018 and a 19 MW reduction in the Companies peak demand forecast by 2028.

**Table 5.(3)-3**
**KU/ODP: Sales Structure and Forecast Growth Rates by Class**

| Class | Percent of 2013 Sales | Percent Annual Growth Rate 2014-2018 | Percent Annual Growth Rate 2014-2028 |
|---|---|---|---|
| **RETAIL** | **91.2%** | | |
| **Kentucky** | **86.7%** | **0.6%** | **0.6%** |
| Residential | 29.0% | 0.7% | 0.9% |
| Commercial | 18.3% | 0.7% | 0.7% |
| Industrial | 32.0% | 0.6% | 0.4% |
| Public Authorities | 7.2% | 0.2% | 0.3% |
| Lighting | 0.2% | 0.6% | 0.2% |
| **Virginia** | **4.4%** | **0.1%** | **0.4%** |
| **WHOLESALE** | **8.8%** | **1.2%** | **1.0%** |
| **TOTAL COMPANY** | **100%** | **0.6%** | **0.6%** |

KU's forecast of total customers and energy sales is summarized in Table 5.(3)-4.

**Table 5.(3)-4**
**Total KU/ODP Customer and Calendar Sales Forecasts (GWh)**

| Year | Customers* | % Growth in Customers | Baseline Energy Sales Forecast after DSM (GWh)* | % Growth in Energy Sales |
|---|---|---|---|---|
| **2013** | 540,895 | | 21,262 | |
| **2014** | 542,922 | 0.4% | 21,773 | 2.4% |
| **2015** | 546,812 | 0.7% | 21,860 | 0.4% |
| **2016** | 550,895 | 0.7% | 22,015 | 0.7% |
| **2017** | 555,008 | 0.7% | 22,158 | 0.6% |
| **2018** | 559,114 | 0.7% | 22,342 | 0.8% |
| **2019** | 562,673 | 0.6% | 22,538 | 0.9% |
| **2020** | 565,830 | 0.6% | 22,699 | 0.7% |
| **2021** | 568,856 | 0.5% | 22,834 | 0.6% |
| **2022** | 571,401 | 0.4% | 22,959 | 0.5% |
| **2023** | 573,557 | 0.4% | 23,077 | 0.5% |
| **2024** | 575,884 | 0.4% | 23,258 | 0.8% |
| **2025** | 578,368 | 0.4% | 23,398 | 0.6% |
| **2026** | 580,940 | 0.4% | 23,546 | 0.6% |
| **2027** | 583,629 | 0.5% | 23,692 | 0.6% |
| **2028** | 586,360 | 0.5% | 23,838 | 0.6% |

*Number of customers in 2013 is an actual value. Energy sales in 2013 are weather-normalized actual values.

### *Kentucky Utilities Peak Demand Forecast*

KU's forecasts of energy requirements and summer peak demand are summarized in Table 5.(3)-5. KU's energy requirements are forecasted to grow at an annual rate of 0.6 percent from 2014 to 2028. KU's summer peak demand is forecasted to grow by 450 MW from 2014 to 2028, an annual growth rate of 0.7 percent.

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

| Year | Energy Requirements, GWh* | Percent Growth in Energy Requirements | Summer Peak, MW* | Percent Growth in Summer Peak |
|---|---|---|---|---|
| **2013** | 22,595 | | 3,943 | |
| **2014** | 23,122 | 2.3% | 4,334 | 9.9% |
| **2015** | 23,213 | 0.4% | 4,360 | 0.6% |
| **2016** | 23,377 | 0.7% | 4,391 | 0.7% |
| **2017** | 23,530 | 0.7% | 4,425 | 0.8% |
| **2018** | 23,723 | 0.8% | 4,462 | 0.8% |
| **2019** | 23,934 | 0.9% | 4,505 | 1.0% |
| **2020** | 24,105 | 0.7% | 4,538 | 0.7% |
| **2021** | 24,244 | 0.6% | 4,577 | 0.9% |
| **2022** | 24,378 | 0.6% | 4,602 | 0.5% |
| **2023** | 24,505 | 0.5% | 4,628 | 0.6% |
| **2024** | 24,701 | 0.8% | 4,670 | 0.9% |
| **2025** | 24,849 | 0.6% | 4,709 | 0.8% |
| **2026** | 25,002 | 0.6% | 4,742 | 0.7% |
| **2027** | 25,154 | 0.6% | 4,767 | 0.5% |
| **2028** | 25,312 | 0.6% | 4,784 | 0.4% |

* Energy requirement in 2013 is a weather-normalized actual value.  Peak demand in 2013 is an actual value.

**Louisville Gas and Electric Company**

***LG&E Customer Growth and Energy Sales***

Table 5.(3)-6 summarizes the five- and fifteen-year growth rates for each LG&E class of sales, along with each class's share of 2013 sales.

LG&E's residential sales are forecasted to grow at a 1.1 percent annual growth rate from 2014 to 2018 and a 1.3 percent annual growth rate from 2014 to 2028. Residential sales growth is driven by an increase in use-per-customer as well as growth in the number of customers. Retail commercial sales are forecasted to grow at only a 0.1 percent rate over the 2014-2018 period. Recent use-per-customer for small commercial customers from 2011 to 2013 was flat or declining as economic growth remained low. Industrial sales are forecasted to be stronger, growing at an annual rate of 1.5 percent from 2014-2018 and 0.9 percent annually from 2014-2028, driven by larger industrial customers. The Public Authority sector is projected to decline at a rate of 0.5 percent, primarily driven by one large government related customer.

**Table 5.(3)-6**
**LG&E: Sales Structure and Forecast Growth Rates by Class**

| Class | Percent of 2013 Sales | Percent Annual Growth Rate 2014-2018 | Percent Annual Growth Rate 2014-2028 |
|---|---|---|---|
| Residential | 35.6% | 1.1% | 1.3% |
| Commercial | 31.5% | 0.1% | 0.1% |
| Industrial | 23.1% | 1.5% | 0.9% |
| Public Authority | 9.7% | -0.5% | 0.0% |
| Lighting | 0.2% | 0.0% | 0.0% |
| LG&E Total | 100.0% | 0.7% | 0.7% |

Table 5.(3)-7 summarizes LG&E's forecast of total customers and sales through 2028.

**Table 5.(3)-7**
**LG&E: Forecasts of Customers and Calendar Sales (GWh)**

| Year | Customers* | % Growth in Customers | Energy Forecast after DSM (GWh)* | % Growth in Energy Sales |
|---|---|---|---|---|
| 2013 | 395,313 | | 11,732 | |
| 2014 | 404,750 | 2.4% | 11,906 | 1.5% |
| 2015 | 407,989 | 0.8% | 11,985 | 0.7% |
| 2016 | 411,348 | 0.8% | 12,078 | 0.8% |
| 2017 | 414,685 | 0.8% | 12,149 | 0.6% |
| 2018 | 418,008 | 0.8% | 12,252 | 0.8% |
| 2019 | 420,920 | 0.7% | 12,351 | 0.8% |
| 2020 | 423,514 | 0.6% | 12,435 | 0.7% |
| 2021 | 426,004 | 0.6% | 12,513 | 0.6% |
| 2022 | 428,112 | 0.5% | 12,595 | 0.7% |
| 2023 | 429,912 | 0.4% | 12,681 | 0.7% |
| 2024 | 431,847 | 0.5% | 12,796 | 0.9% |
| 2025 | 433,809 | 0.5% | 12,886 | 0.7% |
| 2026 | 435,779 | 0.5% | 12,976 | 0.7% |
| 2027 | 437,757 | 0.5% | 13,082 | 0.8% |
| 2028 | 439,743 | 0.5% | 13,200 | 0.9% |

*The number of customers in 2013 is an actual value. Energy in 2013 is a weather-normalized actual value.

***LG&E Peak Demand Forecast***

Table 5.(3)-8 contains LG&E's forecasted energy requirements and summer peak demand. LG&E's energy requirements are forecasted to grow at an average annual rate of 0.7 percent from 2014 to 2028. Over the same period, LG&E's summer peak demand is forecasted to grow by 327 MW, an annual growth rate of 0.8 percent.

**Table 5.(3)-8**
**LG&E: Forecast Energy Requirements and Peak Demand after DSM**

| Year | Energy Requirements, GWh* | Percent Growth | Summer Peak, MW* | Percent Growth |
|---|---|---|---|---|
| **2013** | 12,279 | | 2,529 | |
| **2014** | 12,594 | 2.6% | 2,655 | 5.0% |
| **2015** | 12,679 | 0.7% | 2,679 | 0.9% |
| **2016** | 12,776 | 0.8% | 2,693 | 0.5% |
| **2017** | 12,853 | 0.6% | 2,720 | 1.0% |
| **2018** | 12,961 | 0.8% | 2,737 | 0.6% |
| **2019** | 13,064 | 0.8% | 2,752 | 0.5% |
| **2020** | 13,155 | 0.7% | 2,779 | 1.0% |
| **2021** | 13,236 | 0.6% | 2,798 | 0.7% |
| **2022** | 13,326 | 0.7% | 2,832 | 1.2% |
| **2023** | 13,417 | 0.7% | 2,860 | 1.0% |
| **2024** | 13,534 | 0.9% | 2,873 | 0.5% |
| **2025** | 13,629 | 0.7% | 2,888 | 0.5% |
| **2026** | 13,729 | 0.7% | 2,912 | 0.8% |
| **2027** | 13,836 | 0.8% | 2,943 | 1.1% |
| **2028** | 13,967 | 0.9% | 2,982 | 1.3% |

* Energy requirement in 2013 is a weather-normalized actual value.  Peak demand in 2013 is an actual value.

**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**

As previously discussed, the Companies' IRP focuses on resource needs from 2019 through 2028 assuming that short-term capacity purchases in 2015-17 and the construction of Green River NGCC and Brown Solar Facility will meet incremental capacity needs through 2018.

The Companies' resource assessment was completed in two parts. First, the Companies performed a screening analysis of more than 50 generation technology options to determine a subset of the most competitive options. Then, this subset of generation technology options was incorporated into a detailed expansion planning analysis to determine optimal expansion plans beyond 2018.

Table 5.(4)-1 lists the technology options identified in the screening analysis as the most competitive options. The 2x1 NGCC G/H-Class option had the lowest levelized cost for capacity factors exceeding 20 percent and is the best option for meeting intermediate and base load energy needs. The option to install three F-Class SCCT units ("SCCT F-Class – Three Units"), was least cost for capacity factors below 20 percent and the best choice for meeting peak energy needs. When tax incentives and the value of selling renewable energy credits were included for renewable technology options, the solar PV and wind technology options were among the most competitive options.

**Table 5.(4)-1**
**List of Technology Options Evaluated in Expansion Planning Analysis**

| 2014 IRP Generation Technology Options |
|---|
| 2x1 NGCC G/H-Class |
| 1x1 NGCC G/H-Class |
| SCCT F Class – Three Units |
| SCCT F Class – One Unit |
| Solar Photovoltaic |
| Wind |

The screening analysis considered F-Class NGCC options in addition to the G/H-Class options. Potential GHG regulation and uncertainty in gas prices make the added efficiency of the G/H-Class option more cost-effective than the F-Class option. Additionally, the capital and fixed costs for the G/H-Class option are lower on a per-kilowatt ("kW") basis. For these reasons, the G/H-Class options were more competitive than the F-Class options.

The list of generation technology options in Table 5.(4)-1 is very similar to the list of technology options that passed the screening analysis for the 2011 IRP. Notable exceptions include the 3x1 NGCC technology option and the supercritical pulverized coal ("PC") technology option. The 3x1 NGCC was excluded from the analysis due to its size; it is difficult for the Companies to recover from the loss of such a large unit given the relatively small size of their generating portfolio. The supercritical PC technology option was not ranked among the least-cost technology options due primarily to its high capital cost and a lower forecast of natural gas prices.[11] In addition, currently proposed federal NSPS for GHG regulations would require

[11] Compared to the 2x1 NGCC G/H-Class option, the capital cost for the supercritical PC option is more than five times higher. The price spread between the Mid natural gas price forecast and the coal price forecast is more than 70% lower in the 2014 IRP compared to the 2011 IRP.

coal units to eventually be equipped with unproven and uneconomic $CO_2$ capture and sequestration technology.

As discussed in the Companies' *2014 Reserve Margin Analysis* (see Volume III, Technical Appendix), the Companies target a minimum 16 percent reserve margin (above peak load after adjusting for DSM programs) for the purpose of developing expansion plans. In the Base load forecast scenario, after the NGCC unit is added at the Green River Station in 2018, the Companies' reserve margin remains above the minimum target level until 2025 (assuming no other changes to the Companies' generation portfolio).

In the Base load forecast scenario, peak demand grows by approximately 800 MWs over the 15-year planning period. While meeting customers' peak demand is critical, it is also vital to reliably serve their energy needs all year round at the lowest reasonable cost. In the Base load forecast scenario, energy requirements are forecasted to grow by 3.6 TWh over the next 15 years even after reductions for DSM.

In the detailed expansion planning analysis, the Companies developed optimal expansion plans using the technology options in Table 5.(4)-1 over multiple natural gas price, load, and $CO_2$ scenarios. The results of the analysis for the Base load scenarios are summarized in Table 5.(4)-2.

**Table 5.(4)-2**
**Optimal Expansion Plans (Base Load Scenarios)[12]**

| $CO_2$ | 0C | 0C | 0C | MC | MC | MC | Cap | Cap | Cap |
|---|---|---|---|---|---|---|---|---|---|
| **Load** | **BL** | **BL** | **BL** | **BL** | **BL** | **BL** | **BL** | **BL** | **BL** |
| **Gas Price** | **LG** | **MG** | **HG** | **LG** | **MG** | **HG** | **LG** | **MG** | **HG** |
| 2014 | | | | | | | | | |
| 2015 | CR7 | CR7 | CR7 | CR7 | CR7 | CR7 | CR7 | CR7 | CR7 |
| 2016 | BRS | BRS | BRS | BRS | BRS | BRS | BRS | BRS | BRS |
| 2017 | | | | | | | | | |
| 2018 | GR5 | GR5 | GR5 | GR5 | GR5 | GR5 | GR5 | GR5 | GR5 |
| 2019 | | | | | | | | | |
| 2020 | | | | Ret BR1-2<br>1x1G(1) | Ret BR1-2<br>1x1G(1) | Ret BR1-2<br>2x1G(1) | Ret BR1-2<br>2x1G(1) | Ret BR1-2<br>2x1G(1) | Ret BR1-2<br>2x1G(1) |
| 2021 | | | | | | | | | |
| 2022 | | | | 2x1G(1) | 2x1G(1) | | | | |
| 2023 | | | | | | | | | |
| 2024 | | | | | | | | | |
| 2025 | 2x1G(1) | SCCT(1) | 2x1G(1) | | | | | | |
| 2026 | | | | | | | | | |
| 2027 | | SCCT(1) | | | | | | | |
| 2028 | | | | | | | | | Wind(4) |

$CO_2$: Zero (0C), Mid (MC), Mass Emissions Cap (Cap)   Load: Base (BL)   Gas Price: Low (LG), Mid (MG), High (HG)

In the Zero $CO_2$ price scenarios, the addition of new capacity (in 2025) coincides with the Companies' need for capacity, as expected. In the Mid $CO_2$ price and $CO_2$ mass emissions cap scenarios, new capacity is added in 2020. Two factors drive this result. First, the system benefits from low $CO_2$-emitting generation in a carbon-constrained world, even when the capacity and energy may not be needed to maintain the target reserve margin; the production cost savings associated with low $CO_2$-emitting generation more than offsets the increased cost of building new generation sooner. Second, in these scenarios, average capacity factors of Brown 1 and 2 were consistently less than 10 percent; therefore, these two units were assumed to be retired in 2020 in these scenarios.

Because NGCC capacity is added first in eight of the nine scenarios in Table 5.(4)-2, a natural gas unit will likely be included in the Companies' least cost plan to meet future load

[12] In Table 5.(4)-2, the value in parentheses following the technology option's reference name indicates the number of units added in a given year.

requirements beyond 2018. In the Zero $CO_2$ price scenarios, NGCC capacity is added to meet customers' growing need for energy (as well as capacity). In the Mid $CO_2$ price and $CO_2$ mass emissions cap scenarios, NGCC capacity is added to meet the need for low-emitting $CO_2$ resources (as well as customers' energy needs). Generally speaking, more NGCC capacity is added sooner in the $CO_2$ mass emissions cap scenarios compared to the Mid $CO_2$ price scenarios. Without this additional capacity, the system cannot economically meet the $CO_2$ mass emissions cap.

In the High gas, $CO_2$ emissions cap scenario, wind capacity is added to the Companies' portfolio in 2028. In the High gas price scenario, gas prices exceed $8/mmBtu beyond 2025. High gas prices coupled with the $CO_2$ mass emissions cap makes wind competitive in this scenario.

A complete discussion of the Companies' resource assessment is included in Volume III, Technical Appendix (see report titled 2014 Resource Assessment).

**Generation Efficiency Improvements**

The plan described in Table 5.(4)-2 did not evaluate the potential for future generation efficiency improvements. However, the Companies continue to evaluate economic improvements to their existing generation fleet, with consideration of the environmental rules for such modifications. Additional details are provided in Section 8.(2)(a).

***Rehabilitation of Hydroelectric Stations***

## OHIO FALLS

The Companies have evaluated and will continue to evaluate the sustainable long-term generation and modernization needs and opportunities for the Ohio Falls Hydroelectric Power Station ("Ohio Falls Station"). The Ohio Falls Station was granted a 40-year operational license by the FERC effective October 25, 2005. 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 and Unit 6 in October 2006 and January 2008, respectively. The rehabilitation project was delayed until 2011 when work began on the next unit. Rehabilitation was completed on Unit 5 and Unit 3 in May 2012 and July 2013, respectively. Rehabilitation work on Unit 1 began in 2013 and the remaining three units are planned to be completed by the end of 2017.

Total rehabilitation of all eight units will result in increasing the expected summer net 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 a potential increase of 187 GWh in annual energy production. The impact of the rehabilitation program is reflected in all of the expansion plan analyses in this IRP.

**DIX DAM**

At the Dix Dam hydro site, Units 1 and 2 underwent complete overhauls in 2011 and 2012, respectively. This included refurbishment of the turbines and generators as well as the wicket gates for both units. Additionally, Unit 2 had the inlet ‘Johnson’ valve replaced due to the likelihood of failure to this vintage of valve. Significant work was also completed to remediate leakage through the face slab joints of the dam. All these efforts improve the reliability and efficiency of the Dix Dam Hydro site. The impact of the rehabilitation program is reflected in all of the expansion plan analyses in this IRP.

In addition to the rehabilitation efforts at the Ohio Falls and Dix Dam Stations, the Companies continue to monitor potential hydro opportunities. However, sites for additional conventional hydro facilities on the Ohio River are limited and no hydro options were identified in this IRP.

**Demand Side Programs**

Demand Side Programs are evaluated for cost effectiveness prior to inclusion in the energy and peak demand forecasts. See Section 8.(3)(e) for a detailed description of DSM programs.

The Companies received approval for their current portfolio of energy efficiency ("EE") programs from the Commission on November 9, 2011, in Case No. 2011-00134. The Companies requested, and the Commission approved, a seven-year plan for programs in light of the significant investment in time and resources required to initiate operations, obtain participants, and achieve the projected demand and energy savings. The two years since the approval of these programs has granted greater insight into program modification opportunities. As a result of the lessons learned, the Companies filed Case No. 2014-00003 with the Commission on January 17, 2014. In this filing, the Companies presented their 2015-2018 DSM/EE Program Plan. The Companies are seeking approval for enhancements to programming in their currently approved portfolio from Case No. 2011-00134, the continuation of one program in approved Case No. 2007-00139, and a new Automated Meter Systems effort. The enhancements of programming being sought will take into account aspects of certain programming that is set to expire December 31, 2014 in Case No. 2007-00139. In this filing, the Companies sought enhancement to the following programs: Commercial Load Management; Residential Incentives; Commercial Conservation; and Residential Conservation.

Moreover, the programs the Commission approved in Case No. 2011-00134 not included in Case No. 2014-00003 that will remain unchanged include: Smart Energy Profile Program, Residential Load Management / Demand Conservation Program, Residential Refrigerator Removal Program, and the Residential Low Income Weatherization Program (WeCare). The Companies propose to continue these existing programs through 2018 as these programs are currently operating satisfactorily within the approved program designs, and therefore do not warrant enhancements at this time.

The proposed program enhancements to the Companies' DSM/EE portfolio will operate through December 31, 2018 and allow the Companies to achieve 500 MW of demand reduction by 2018. See Section 6 for a discussion of DSM included in the load forecast for the 2014 IRP compared to the 2011 IRP.

**New Power Plants**

In 2011, the Companies announced plans to retire approximately 800 MW of coal-fired capacity to comply with the U.S. EPA's National Ambient Air Quality Standards and Mercury and Air Toxics Standards. In February 2013, the Companies retired Tyrone 3; the IRP assumes the three Cane Run and two Green River coal units will be retired in 2015. To offset this loss of energy and capacity, the Companies proposed to construct a 640 MW 2x1 NGCC unit at their Cane Run site ("Cane Run 7" or "CR7") to be online in 2015 and purchase the existing LS Power Bluegrass facility in LaGrange, Kentucky (495 MW of SCCTs).[13]

[13] See Case No. 2011-00375, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined-cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple-cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky* (Kentucky Public Service Commission ("KY PSC") May 3, 2012).

The construction of Cane Run 7 is underway and on schedule. However, the Companies were unable to purchase the Bluegrass facility after receiving an unfavorable Federal Energy Regulatory Commission ("FERC") ruling in May 2012.[14] To acquire the Bluegrass facility, the Companies needed authorization from FERC to complete the transaction under section 203 of the Federal Power Act. Therefore, in November 2011, the Companies and Bluegrass Generation Company, a subsidiary of LS Power, filed an application with FERC requesting authorization to complete the transaction. In its review of the application, FERC found that the proposed transaction resulted in significant screen failures in the horizontal market power analysis. As a result, FERC conditionally authorized the transaction, subject to the Companies proposing adequate mitigation to remedy the identified screen failures.

After reviewing the regulatory, operational, and economic impacts of the mitigation measures, the Companies determined that the mitigation measures were not acceptable because they would have resulted in higher costs to the Companies' customers. Therefore, in June 2012, the Companies terminated their agreement to purchase the Bluegrass facility.[15]

After the Companies prepared their 2013 Load Forecast ("2013 LF") in the summer of 2012, it was clear that additional resources would be required as early as 2015 to reliably serve customers' capacity and energy needs. To meet this need for capacity and energy, the Companies issued a request for proposals ("RFP") in September 2012 for capacity and energy. In addition to the RFP responses, the Companies also evaluated new demand-side management programs and self-build alternatives. As a result of this analysis, the Companies applied for

[14] Order Conditionally Authorizing Disposition and Acquisition of Jurisdictional Facilities and Acquisition of Generating Facilities, Docket No. EC12-29-000, May 4, 2012, 139 FERC ¶ 61,094. For the Order, see http://www.ferc.gov/EventCalendar/Files/20120504160345-EC12-29-000.pdf.

[15] On June 18, 2012, the Companies sent a letter to KY PSC informing them of the decision not to proceed with the Bluegrass acquisition.

Certificates of Public Convenience and Necessity ("CPCN") in January 2014 for a 10 MW solar PV project in 2016 at the E.W. Brown station ("Brown Solar") and a 670 MW 2x1 NGCC unit in 2018 at the Green River station ("Green River 5" or "GR5"). The CPCN does not address the Companies' need for capacity and energy in 2015 through 2017. The Companies plan to address this need by exploring all available options, including (but not limited to) alternatives from parties that provided responses to the September 2012 RFP and extending the life of Green River units 3 and 4. As mentioned previously, Cane Run 7, the short-term capacity additions in 2015 through 2017, and the proposed solar PV and NGCC facilities complete the Companies' expansion plan through 2018.

**Non-Utility Sources of Generation**

With the addition of Brown Solar, the Companies will continue to have a reserve margin shortfall in 2015 to 2017. The Companies are pursuing negotiations for a short-term PPA to address capacity and energy needs in these years.

**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**

LG&E and KU have purchase power arrangements with OVEC to provide additional sources of capacity. OVEC was originally formed for the purpose of providing electric power requirements projected for the uranium enrichment complex being built near Portsmouth, Ohio.

In 1993, the United States Enrichment Corporation was formed to lease the uranium enrichment facilities from the United States Department of Energy ("DOE") and assume the responsibility for uranium enrichment services for the U.S. The DOE gave notice of reductions in its contract demand for electricity, with power and energy no longer requested after Aug. 31, 2001. The power and energy thus released from the plants became available to the sponsoring companies under the Inter-Company Power Agreement ("ICPA"). OVEC's Kyger Creek Plant at Cheshire, Ohio, and Indiana-Kentucky Electric Corporation's Clifty Creek Plant at Madison, Indiana have net summer generating capacities of 956 MW and 1,164 MW, respectively.

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

Beginning in April 2006, LG&E's portion of the power participation benefits became 5.63 percent pursuant to the Amended and Restated ICPA dated as of March 13, 2006, filed with and approved by the KPSC in Case No. 2004-00396. KU retained its 2.5 percent ownership. During the 2014 summer peak, the Companies plan to receive 172 MW net and varying capacities during the remaining months due to unit maintenance schedules on the OVEC system. The owners of OVEC and various regulatory bodies including the KPSC have approved an extension of the ICPA to 2040 in order to improve the financing of existing debt associated with environmental compliance equipment at both Kyger and Clifty Creek plants.

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

**Resource Assessment**

Based on this resource assessment, the earliest the Companies would need additional generation capacity is 2020, and then only if $CO_2$ regulations on existing units would require the retirement of Brown 1 and 2 and the addition of low carbon generation. Otherwise, new generation capacity will not be needed until 2025. As part of implementing this plan during the next three years, the Companies will closely monitor the development of environmental regulations and will undertake all studies and other long lead activities necessary to make decisions regarding existing and future generating resources.

**Demand-Side Management**

Upon approval of their January 17, 2014 DSM filing (Case No. 2014-0003), the Companies will implement all approved enhancements as quickly as reasonably possible. The remaining unchanged programs in the portfolio will operate as previously approved through 2018.

As the programs are implemented, the Companies will perform ongoing impact evaluation focusing on quantifying the energy and demand savings and other economic benefits of the enhanced, new and existing /unchanged programs in the DSM/EE portfolio. The proposal in front of the Commission will allow the Companies to align its DSM/EE portfolio with all programs approval ending in 2018. This methodology will allow the Companies an opportunity to review its portfolio holistically in conjunction with a market place perspective as well as the utility cost perspective, thus allowing the Companies to evaluate additional programming with potentially new energy efficiency technologies as they become economically viable.

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

### Environmental Regulations Uncertainty

The Companies future expansion plan is highly dependent on whether or not there are regulations of GHG emissions on existing generating units. GHG regulation could have a significant impact on the Companies' optimal expansion plan by making low carbon generation more competitive and potentially resulting in the economic retirement of existing units, which would accelerate the need for additional generating resources.

### 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 2014 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 after DSM (GWh)**

| Year | Base Energy Requirements | High Energy Requirements | Low Energy Requirements |
|---|---|---|---|
| **2014** | 35,716 | 37,379 | 34,053 |
| **2015** | 35,892 | 37,621 | 34,164 |
| **2016** | 36,153 | 37,935 | 34,371 |
| **2017** | 36,383 | 38,232 | 34,535 |
| **2018** | 36,684 | 38,604 | 34,765 |
| **2019** | 36,998 | 39,005 | 34,992 |
| **2020** | 37,260 | 39,369 | 35,151 |
| **2021** | 37,479 | 39,696 | 35,263 |
| **2022** | 37,704 | 40,027 | 35,381 |
| **2023** | 37,922 | 40,350 | 35,495 |
| **2024** | 38,235 | 40,766 | 35,705 |
| **2025** | 38,478 | 41,122 | 35,833 |
| **2026** | 38,731 | 41,490 | 35,972 |
| **2027** | 38,990 | 41,865 | 36,115 |
| **2028** | 39,279 | 42,272 | 36,285 |

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

| Year | Base Peak | High Peak | Low Peak |
|---|---|---|---|
| **2014** | 6,972 | 7,294 | 6,651 |
| **2015** | 7,028 | 7,362 | 6,694 |
| **2016** | 7,085 | 7,429 | 6,741 |
| **2017** | 7,142 | 7,499 | 6,784 |
| **2018** | 7,199 | 7,570 | 6,828 |
| **2019** | 7,257 | 7,645 | 6,869 |
| **2020** | 7,315 | 7,723 | 6,907 |
| **2021** | 7,374 | 7,804 | 6,944 |
| **2022** | 7,433 | 7,885 | 6,982 |
| **2023** | 7,488 | 7,960 | 7,015 |
| **2024** | 7,542 | 8,035 | 7,050 |
| **2025** | 7,598 | 8,114 | 7,081 |
| **2026** | 7,653 | 8,193 | 7,114 |
| **2027** | 7,709 | 8,272 | 7,147 |
| **2028** | 7,766 | 8,351 | 7,180 |

Energy and peak demand grow at similar rates in each of the three load scenarios. The Low load scenario reflects an environment where a significant portion of the Companies' load is lost. Compared to the Base load scenario, peak demand in the Low load scenario is approximately 300 MWs lower in 2014. The High load scenario reflects an environment where a significant amount of load is gained. Compared to the Base load scenario, peak demand in the High load scenario is approximately 300 MWs higher in 2014.

**DSM Implementation**

Due to the voluntary nature of the DSM/EE programs offered by the Companies, the amount of customer participation directly impacts the energy and demand reduction of the designed programs. The enhanced programming in their Demand Side Management/Energy Efficiency filing attempts to address instances where customer participation has fallen below projected levels by including modification of financial incentives and additional opportunities for customers to participate in programming that provide the most energy and demand savings for the Companies. However, for purposes of preparing the IRP, there is no additional uncertainty related to the achievement of DSM expect as reflected in the overall load forecast uncertainty described above.

**Aging Units**

Post 2015, the two oldest steam generating units in the system are Brown Units 1 and 2. Each of these units is over 50 years old. Some of the oldest combustion turbines are the smaller LG&E combustion turbines and the KU Haefling combustion turbines ("CTs"). Each of these units is over 30 years of age, which is considered the typical design life for small frame combustion turbines. Table 5.(6)-3 lists the ages of the oldest units.

**Table 5.(6)-3**
**Aging Units**

| Fuel | Plant Name | Unit | Summer Net Capacity | In Service Year | Age (2014) |
|---|---|---|---|---|---|
| Coal | Brown | 1 | 106 | 1957 | 57 |
| Coal | Brown | 2 | 166 | 1963 | 51 |
| Gas | Cane Run | 11 | 14 | 1968 | 46 |
| Gas | Paddy's Run | 11 | 12 | 1968 | 46 |
| Gas | Paddy's Run | 12 | 23 | 1968 | 46 |
| Gas | Zorn | 1 | 14 | 1969 | 45 |
| Gas | Haefling | 1,2 | 24 | 1970 | 44 |

The Companies periodically perform high-level condition and performance assessments on their generating units. Additionally, the Black and Veatch performed a remaining life assessment on Brown 1 and 2 in 2012. The assessment concluded that these units could operate reliably for the foreseeable future provided that the units continued to be appropriately operated and maintained.

The economics surrounding the continued operation of the Companies' older units will continue to be reviewed periodically to ensure the efficiency of the overall system. More stringent environmental regulations could result in the retirement of these units even without a significant mechanical failure.

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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 2011 Joint IRP of LG&E and KU. Several significant changes have taken place since that filing. These changes are described in the sections that follow.

## RESOURCE ASSESSMENT

The resource assessment 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 the uncertainty associated with various economic and environmental factors. Just as in the 2011 plan, natural gas-fired combined cycle technology continues to be the preferred supply-side resource in the 2014 plan even though the size and timing has changed.

In the 2011 plan, three 3x1 combined cycle combustion turbines (one in 2016, one in 2018, and one in 2025) were the lowest reasonable cost technologies selected to meet the future energy needs of the Companies' customers. The 2014 plan reflects the construction of the 2x1 Cane Run 7 NGCC and the proposed 2x1 Green River NGCC. Beyond that, the Companies developed expansion plans over multiple load, gas price, and $CO_2$ scenarios. The $CO_2$ scenarios include: 1) a Zero $CO_2$ price scenario, where there is never a price on future $CO_2$ emissions; 2) a Mid $CO_2$ price scenario, where a price on each ton of $CO_2$ begins in 2020; and 3) a $CO_2$ mass emissions cap scenario, where $CO_2$ emissions are limited to 29.4 million tons per year beginning in 2020. In the Zero $CO_2$ price scenarios, NGCC capacity is added to meet customers' growing need for energy (as well as capacity). In the Mid $CO_2$ price and $CO_2$ mass emissions cap scenarios, NGCC capacity is added to meet the need for low-emitting $CO_2$ resources (as well as customers' energy needs). In this analysis, the Companies did not consider one scenario to be more likely than another.

## LOAD FORECAST

### *Combined Company*

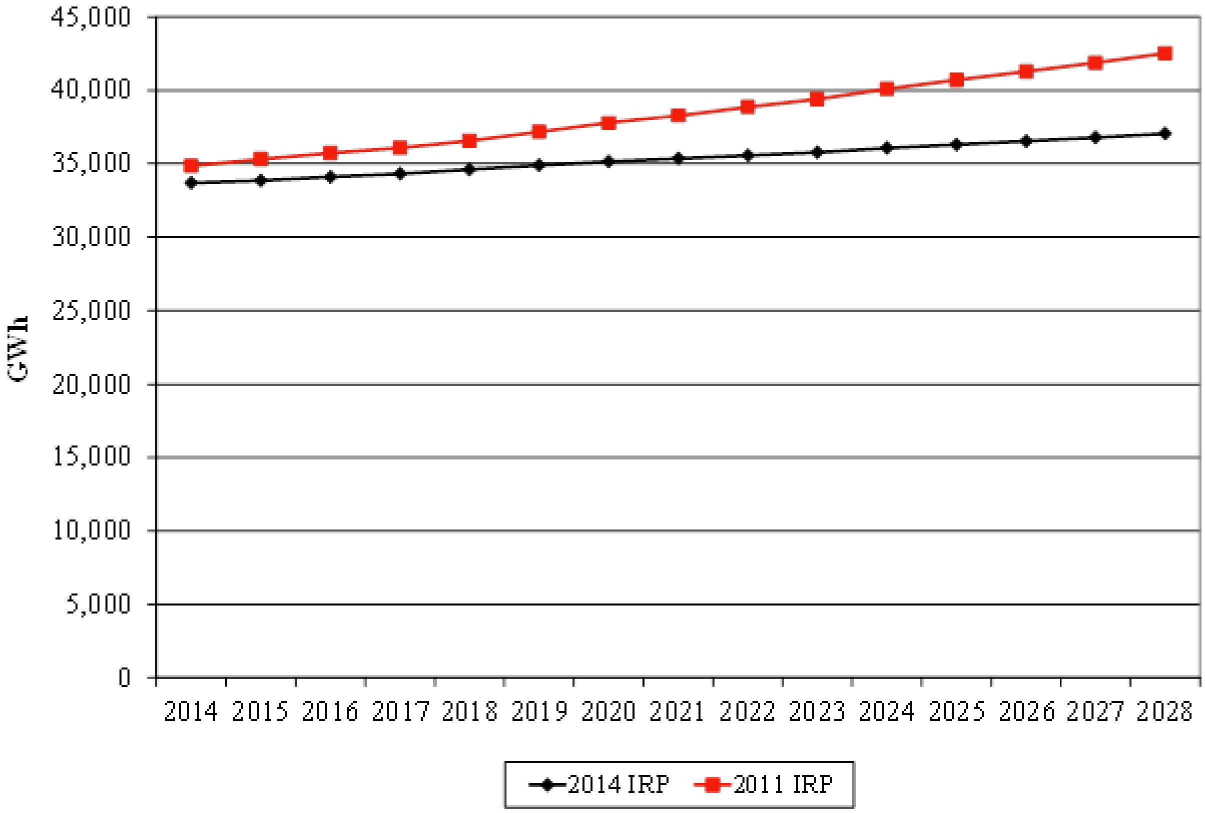
The changes to the 2014 IRP load forecast compared to the 2011 IRP are significant. Typically, energy sales return to prior growth rates quickly after a recession. In the 2011 IRP, the forecasts produced by Global Insight predicted higher economic growth and a "V-shaped" recovery. In actuality, the recovery has been described as "L-shaped" because of a much slower return of jobs and economic growth. As a result, the Companies reevaluated their econometric models and began using employment indices in addition to RGSP and income as drivers in the 2014 IRP. In particular, Residential and Commercial sales have been slow to recover. Customer growth in the Residential class stalled over the 2010-2013 period as the housing market struggled and household growth stalled. The Commercial class experienced a continued decline in sales after the recession ended as the loss in jobs directly impacted disposable income and Commercial sales. When the recession ended in 2009, Industrial sales began to recover and larger industrial companies resumed some hiring. In summary, the stronger economic recovery associated with the Global Insight forecast of economic attributes used in the 2011 IRP load forecast did not occur. The Companies have adjusted the 2014 IRP load forecast accordingly, resulting in significant reductions in energy requirements and associated demand.

The load forecast for energy and demand is presented after the inclusion of the Companies' DSM programs. See Section 8.(3)(e)(3) for further discussion of DSM programs. The Companies are forecasting both a downward shift in forecasted sales in the near-term years, as well as a continuing lower-than-historical growth rate in the latter years of the period. The change in sales for each year is shown in Table 6.(1)-1 and in Graph 6.(1)-1. Compared to the 2011 IRP, the 2014 IRP Combined Companies' sales forecast for the 2014-2018 period has been reduced by an average of 1,587 GWh per year (-4.4 percent). The forecasted annual growth rate in sales during this period is also lower (0.7 percent versus 1.2 percent). By 2028, the lower forecasted growth rate results in sales projected to be 12.9 percent below the 2011 IRP level for 2028. With annual growth rates for 2014-2028 at one half the level of the 2011 IRP, the sales level previously forecasted to be reached in 2018 is now forecasted for 2027. The 2014 IRP incorporates the ongoing trend of slower growth in energy requirements evident since the 2008-2009 recession. Recent results from 2011 to 2013 continue this trend. Economic forecasts since the 2011 IRP have consistently been adjusted downward. In the 2011 IRP, Kentucky RGSP was forecasted to grow 2.6 percent annually from 2011 to 2013 compared to an actual annual growth rate of 1.8 percent. Class-specific discussions of the variances between the 2014 IRP and 2011 IRP forecasts for energy sales are discussed in the individual utility sections below.

**Table 6.(1)-1**
**Combined Companies' 2014 and 2011 IRP Calendar Sales Forecasts after DSM**

| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| **2014** | 33,681 | 34,841 | -1,160 | -3.3% |
| **2015** | 33,845 | 35,298 | -1,453 | -4.1% |
| **2016** | 34,092 | 35,709 | -1,617 | -4.5% |
| **2017** | 34,307 | 36,061 | -1,754 | -4.9% |
| **2018** | 34,593 | 36,544 | -1,951 | -5.3% |
| **2019** | 34,888 | 37,152 | -2,264 | -6.1% |
| **2020** | 35,135 | 37,768 | -2,633 | -7.0% |
| **2021** | 35,348 | 38,275 | -2,928 | -7.6% |
| **2022** | 35,554 | 38,873 | -3,319 | -8.5% |
| **2023** | 35,758 | 39,411 | -3,652 | -9.3% |
| **2024** | 36,054 | 40,105 | -4,051 | -10.1% |
| **2025** | 36,286 | 40,708 | -4,423 | -10.9% |
| **2026** | 36,522 | 41,285 | -4,762 | -11.5% |
| **2027** | 36,773 | 41,879 | -5,107 | -12.2% |
| **2028** | 37,037 | 42,529 | -5,492 | -12.9% |
| **2014-2018 AVG** | 0.7% | 1.2% | -1,587 | -4.4% |
| **2014-2028 AVG** | 0.7% | 1.4% | -3,104 | -7.9% |

**Graph 6.(1)-1**
**Combined Company Calendar Sales after DSM - 2014 vs. 2011 IRP Forecasts (GWh)**

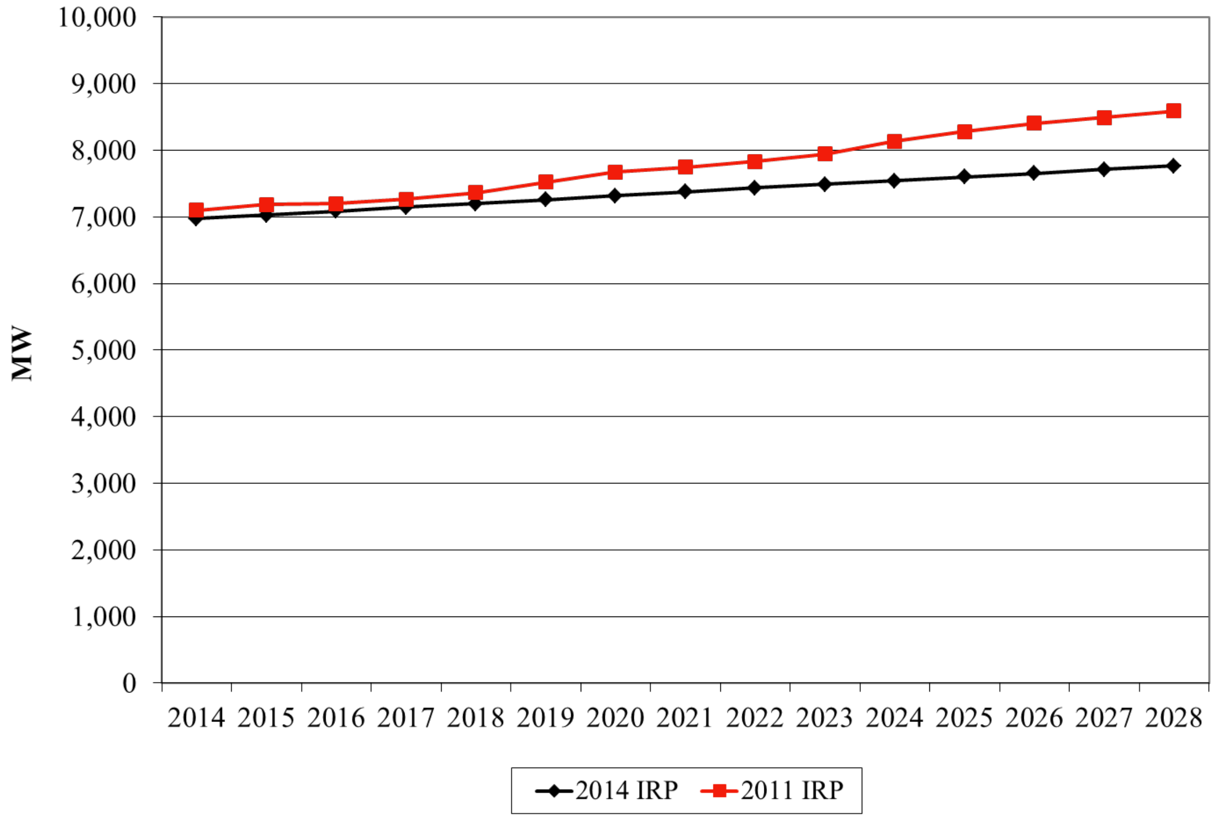



Combined company peak demand in the 2014 IRP is 9.6 percent lower than the 2011 IRP by 2028. After accounting for the changes in DSM since the 2011 IRP (see the Demand Side Management Discussion later in Section 6 and Table 6.(1)-23), the overall reduction in the peak demand forecasted in the 2014 IRP is consistent with the change in forecasted energy sales from 2014-2028. The forecasted annual growth rate in peak demand from 2014-2028 is 0.8 percent versus 1.4 percent in the 2011 IRP. The change in peak demand for each year is shown in Table 6.(1)-2 and in Graph 6.(1)-2.

**Table 6.(1)-2**
**Combined Companies' 2014 and 2011 IRP Peak Demand Forecasts after DSM**

| Year | 2014 IRP (MW) | 2011 IRP (MW) | Change (MW) | % Change |
|---|---|---|---|---|
| **2014** | 6,972 | 7,099 | -127 | -1.8% |
| **2015** | 7,028 | 7,185 | -156 | -2.2% |
| **2016** | 7,085 | 7,196 | -111 | -1.5% |
| **2017** | 7,142 | 7,260 | -119 | -1.6% |
| **2018** | 7,199 | 7,359 | -160 | -2.2% |
| **2019** | 7,257 | 7,519 | -262 | -3.5% |
| **2020** | 7,315 | 7,672 | -357 | -4.6% |
| **2021** | 7,374 | 7,741 | -367 | -4.7% |
| **2022** | 7,433 | 7,829 | -396 | -5.1% |
| **2023** | 7,488 | 7,945 | -457 | -5.8% |
| **2024** | 7,542 | 8,133 | -591 | -7.3% |
| **2025** | 7,598 | 8,282 | -684 | -8.3% |
| **2026** | 7,653 | 8,403 | -750 | -8.9% |
| **2027** | 7,709 | 8,488 | -779 | -9.2% |
| **2028** | 7,766 | 8,589 | -823 | -9.6% |
| **2014-2018 AVG** | 0.8% | 0.9% | -134 | -1.9% |
| **2014-2028 AVG** | 0.8% | 1.4% | -409 | -5.1% |

**Graph 6.(1)-2**
**Combined Companies' Peak Demand – 2014 vs. 2011 IRP Forecasts after DSM (MW)**



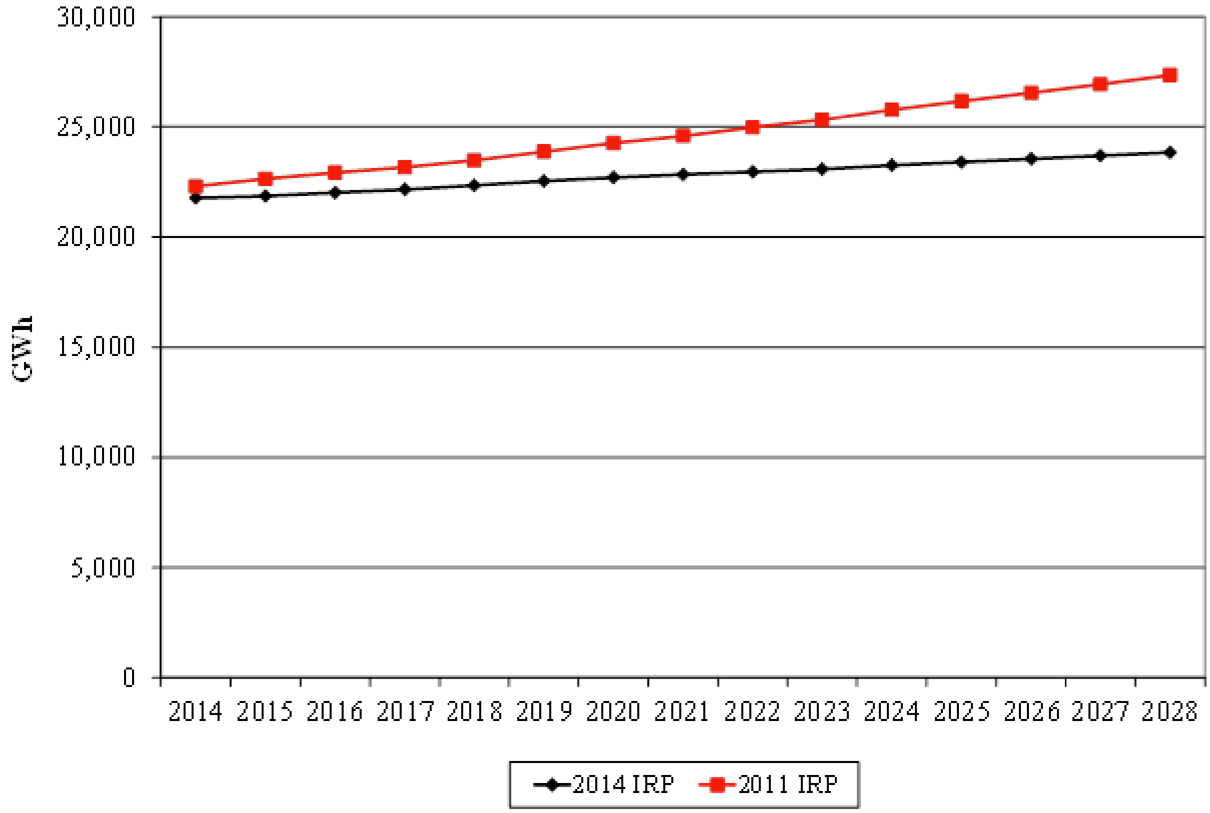

***Kentucky Utilities Company***

Compared to the 2011 IRP, the 2014 IRP forecast for KU sales for the 2014-2018 period has decreased by an average of 870 GWh per year (-3.8 percent). The forecasted growth rate for sales during this period has decreased from an annual growth rate of 1.3 percent in the 2011 IRP to 0.6 percent in the 2014 IRP. The forecasted growth rate for sales during 2014-2028 has also decreased, from an annual growth rate of 1.5 percent in the 2011 IRP to 0.6 percent in the 2014 IRP. The downward shift in sales projections is driven primarily by slower than forecasted economic recovery as well as the slower than forecasted future economic growth. As the recession ended in 2009, economic activity turned slowly positive but sales growth remained flat. Regression equations take into account relationships between series of data to develop coefficients of variables to forecast the future. The impact of three years of slow or flat growth with positive economic activity indicates a change in the relationship between energy sales and economic indices. As such, the forecast models in the 2014 IRP forecast slower growth associated with slightly positive economic activity. The change in KU sales for each year is shown in Table 6.(1)-3 and in Graph 6.(1)-3.

**Table 6.(1)-3**
**Comparison of KU's 2014 and 2011 IRP Calendar Sales Forecasts after DSM**

| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| **2014** | 21,774 | 22,302 | -528 | -2.4% |
| **2015** | 21,860 | 22,639 | -778 | -3.4% |
| **2016** | 22,016 | 22,919 | -903 | -3.9% |
| **2017** | 22,159 | 23,160 | -1,001 | -4.3% |
| **2018** | 22,340 | 23,476 | -1,136 | -4.8% |
| **2019** | 22,537 | 23,871 | -1,335 | -5.6% |
| **2020** | 22,700 | 24,260 | -1,560 | -6.4% |
| **2021** | 22,834 | 24,583 | -1,749 | -7.1% |
| **2022** | 22,958 | 24,973 | -2,014 | -8.1% |
| **2023** | 23,077 | 25,324 | -2,247 | -8.9% |
| **2024** | 23,259 | 25,783 | -2,525 | -9.8% |
| **2025** | 23,399 | 26,185 | -2,785 | -10.6% |
| **2026** | 23,545 | 26,561 | -3,016 | -11.4% |
| **2027** | 23,692 | 26,943 | -3,251 | -12.1% |
| **2028** | 23,837 | 27,361 | -3,524 | -12.9% |
| **2014-2018 AVG** | 0.6% | 1.3% | -870 | -3.8% |
| **2014-2028 AVG** | 0.6% | 1.5% | -1,890 | -7.4% |

**Graph 6.(1)-3**
**KU 2014 vs. 2011 IRP Calendar Sales Forecast Comparison after DSM (GWh)**




Compared to the 2011 IRP, the 2014 IRP KU Residential sales forecast for the 2014-2018 period (see Table 6.(1)-4) has decreased by an average of 160 GWh per year (2.3 percent). The forecasted growth rate for sales during this period has decreased from an annual growth rate of 1.3 percent in the 2011 IRP to 0.7 percent in the 2014 IRP, driven primarily by a decrease in use-per-customer growth. From 2014-2028, the annual growth rate in the 2014 IRP is 0.9 percent compared to 1.6 percent in the 2011 IRP.

While annual customer growth rates are generally consistent between the 2011 IRP and the 2014 IRP (see Table 6.(1)-5), the number of customers forecasted in the 2014 IRP for 2014 is 13,316 lower than forecasted in the 2011 IRP as a result of lower growth since 2011. Household forecasts indicate a return to positive growth after three years of little or no growth. In 2018, Residential sales are 230 GWh (-3.2 percent) lower in the 2014 IRP compared to the 2011 IRP. The difference is due to fewer customers in 2018 (172 GWh) and lower use per customer (58 GWh).

**Table 6.(1)-4**
**Comparison of KU's 2014 and 2011 IRP Residential Calendar Sales Forecasts after DSM**

| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| 2014 | 6,727 | 6,776 | -49 | -0.7% |
| 2015 | 6,744 | 6,873 | -128 | -1.9% |
| 2016 | 6,792 | 6,974 | -182 | -2.6% |
| 2017 | 6,834 | 7,045 | -211 | -3.0% |
| 2018 | 6,911 | 7,141 | -230 | -3.2% |
| 2019 | 6,996 | 7,260 | -264 | -3.6% |
| 2020 | 7,056 | 7,380 | -325 | -4.4% |
| 2021 | 7,119 | 7,487 | -367 | -4.9% |
| 2022 | 7,187 | 7,608 | -421 | -5.5% |
| 2023 | 7,241 | 7,717 | -476 | -6.2% |
| 2024 | 7,334 | 7,886 | -552 | -7.0% |
| 2025 | 7,397 | 8,022 | -625 | -7.8% |
| 2026 | 7,463 | 8,162 | -698 | -8.6% |
| 2027 | 7,529 | 8,302 | -772 | -9.3% |
| 2028 | 7,611 | 8,443 | -832 | -9.9% |
| **2014-2018 AVG** | 0.7% | 1.3% | -160 | -2.3% |
| **2014-2028 AVG** | 0.9% | 1.6% | -409 | -5.2% |

**Table 6.(1)-5**
**Comparison of KU's 2014 and 2011 IRP Residential Customer Forecasts**

| Year | 2014 IRP | 2011 IRP | Change | % Change |
|---|---|---|---|---|
| 2014 | 450,199 | 463,515 | (13,316) | -2.9% |
| 2015 | 454,059 | 467,047 | (12,989) | -2.8% |
| 2016 | 458,065 | 470,765 | (12,700) | -2.7% |
| 2017 | 462,047 | 474,180 | (12,133) | -2.6% |
| 2018 | 465,996 | 477,622 | (11,626) | -2.4% |
| 2019 | 469,411 | 481,075 | (11,664) | -2.4% |
| 2020 | 472,425 | 484,471 | (12,046) | -2.5% |
| 2021 | 475,308 | 487,796 | (12,488) | -2.6% |
| 2022 | 477,709 | 491,030 | (13,321) | -2.7% |
| 2023 | 479,722 | 494,363 | (14,641) | -3.0% |
| 2024 | 481,905 | 497,529 | (15,624) | -3.1% |
| 2025 | 484,246 | 500,723 | (16,477) | -3.3% |
| 2026 | 486,674 | 503,946 | (17,272) | -3.4% |
| 2027 | 489,220 | 507,089 | (17,869) | -3.5% |
| 2028 | 491,808 | 510,182 | (18,375) | -3.6% |
| **2014-2018 AVG** | 0.9% | 0.8% | (12,553) | -2.7% |
| **2014-2028 AVG** | 0.6% | 0.7% | (14,169) | -2.9% |

Compared to the 2011 IRP, the 2014 IRP KU Commercial sales forecast (see Table 6.(1)-6) for the 2014-2018 period has decreased by an average of 859 GWh per year (16.6 percent). The forecasted growth rate for sales during this period has decreased from an annual growth rate of 1.4 percent in the 2011 IRP to 0.7 percent in the 2014 IRP. The KU Commercial class also contains some larger customers that are more industrial in nature. These customers result in a higher annual growth rate for the KU Commercial class than would otherwise be the case. The 2014 IRP's forecast for 2014 sales is 15 percent lower than in the 2011 IRP. KU Commercial sales were slow to recover after the recession in 2008 and 2009 as some Large Commercial customers closed their businesses. In addition, by late 2011, 137 customers changed from a Commercial to an Industrial classification, further lowering the base line for the 2014 IRP forecast. For 2014-2028, commercial sales are forecasted to grow at an annual rate of 0.6 percent compared to a forecast of 1.6 percent in the 2011 IRP.

In 2018, Commercial sales are 937 GWh (17.7 percent) lower in the 2014 IRP compared to the 2011 IRP. Approximately 184 GWh of the decrease is due to customers switching from the Commercial to Industrial class, approximately 608 GWh is due to significantly reduced growth in the historical data series, and 145 GWh is attributable to the inclusion of employment indices as a key forecast input.

**Table 6.(1)-6**
**Comparison of KU's 2014 and 2011 IRP Commercial Calendar Sales Forecasts after DSM**

| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| 2014 | 4,257 | 5,020 | -763 | -15.2% |
| 2015 | 4,272 | 5,103 | -831 | -16.3% |
| 2016 | 4,307 | 5,178 | -870 | -16.8% |
| 2017 | 4,337 | 5,231 | -894 | -17.1% |
| 2018 | 4,370 | 5,307 | -937 | -17.7% |
| 2019 | 4,398 | 5,406 | -1,007 | -18.6% |
| 2020 | 4,428 | 5,509 | -1,080 | -19.6% |
| 2021 | 4,448 | 5,584 | -1,136 | -20.3% |
| 2022 | 4,468 | 5,685 | -1,217 | -21.4% |
| 2023 | 4,490 | 5,767 | -1,277 | -22.1% |
| 2024 | 4,525 | 5,878 | -1,353 | -23.0% |
| 2025 | 4,555 | 5,978 | -1,423 | -23.8% |
| 2026 | 4,584 | 6,054 | -1,469 | -24.3% |
| 2027 | 4,617 | 6,136 | -1,519 | -24.8% |
| 2028 | 4,650 | 6,240 | -1,591 | -25.5% |
| **2014-2018 AVG** | 0.7% | 1.4% | -859 | -16.6% |
| **2014-2028 AVG** | 0.6% | 1.6% | -1,158 | -20.4% |

Compared to the 2011 IRP, the 2014 IRP KU Industrial sales forecast for the 2014-2018 period (see Table 6.(1)-7) has increased by an average of 475 GWh per year (7.0 percent). The forecasted growth rate for sales during this period has decreased from an annual growth rate of

1.5 percent in the 2011 IRP to 0.6 percent in the 2014 IRP driven primarily by slower growth in retail and wholesale employment growth, and Industrial Production. However, major Industrial customers increased production in 2011-2013, and 137 customers changed from Commercial to Industrial classification. Approximately, 138 GWh of sales per year switched from the Commercial to the Industrial class between August 2010 and August 2011. Both of these factors contributed to the 9.1 percent increase in the base line for the 2014 IRP's forecast for 2014 sales. Over the 2014-2028 period, the KU industrial class is forecasted to grow at an annual rate of 0.4 percent in the 2014 IRP versus 1.6 percent in the 2011 IRP, driven primarily by slower growth in retail and wholesale employment growth, and Industrial Production.

**Table 6.(1)-7**
**Comparison of KU's 2014 and 2011 IRP Industrial Calendar Sales Forecasts**

| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| 2014 | 7,188 | 6,590 | 597 | 9.1% |
| 2015 | 7,226 | 6,715 | 511 | 7.6% |
| 2016 | 7,268 | 6,792 | 476 | 7.0% |
| 2017 | 7,307 | 6,879 | 428 | 6.2% |
| 2018 | 7,350 | 6,987 | 363 | 5.2% |
| 2019 | 7,404 | 7,116 | 288 | 4.0% |
| 2020 | 7,451 | 7,237 | 214 | 3.0% |
| 2021 | 7,482 | 7,338 | 144 | 2.0% |
| 2022 | 7,500 | 7,458 | 42 | 0.6% |
| 2023 | 7,519 | 7,574 | -55 | -0.7% |
| 2024 | 7,546 | 7,702 | -156 | -2.0% |
| 2025 | 7,568 | 7,823 | -255 | -3.3% |
| 2026 | 7,592 | 7,940 | -348 | -4.4% |
| 2027 | 7,614 | 8,054 | -441 | -5.5% |
| 2028 | 7,621 | 8,177 | -556 | -6.8% |
| **2014-2018 AVG** | 0.6% | 1.5% | 475 | 7.0% |
| **2014-2028 AVG** | 0.4% | 1.6% | 83 | 1.5% |

Compared to the 2011 IRP, the 2014 IRP KU Public Authority (primarily comprised of government entities) sales forecast for the 2014-2018 period (see Table 6.(1)-8) has decreased by an average of 255 GWh per year (13.5 percent). The forecasted growth rate for sales during this period has decreased from an annual growth rate of 1.0 percent in the 2011 IRP to 0.2 percent in the 2014 IRP. Since 2011, Public Authority sales have been lower than forecasted in the 2011 IRP. The 2014 IRP forecasts this lower growth rate to continue during the 2014-2028 period.

**Table 6.(1)-8**
**Comparison of KU's 2014 and 2011 IRP Public Authority Calendar Sales Forecasts after DSM**

| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| 2014 | 1,632 | 1,849 | -217 | -11.7% |
| 2015 | 1,624 | 1,874 | -249 | -13.3% |
| 2016 | 1,629 | 1,890 | -261 | -13.8% |
| 2017 | 1,639 | 1,905 | -266 | -14.0% |
| 2018 | 1,646 | 1,925 | -279 | -14.5% |
| 2019 | 1,655 | 1,955 | -300 | -15.4% |
| 2020 | 1,662 | 1,986 | -324 | -16.3% |
| 2021 | 1,665 | 2,011 | -346 | -17.2% |
| 2022 | 1,667 | 2,041 | -374 | -18.3% |
| 2023 | 1,672 | 2,066 | -394 | -19.1% |
| 2024 | 1,680 | 2,098 | -418 | -19.9% |
| 2025 | 1,686 | 2,126 | -440 | -20.7% |
| 2026 | 1,693 | 2,150 | -458 | -21.3% |
| 2027 | 1,699 | 2,175 | -476 | -21.9% |
| 2028 | 1,703 | 2,205 | -502 | -22.8% |
| **2014-2018 AVG** | 0.2% | 1.0% | -255 | -13.5% |
| **2014-2028 AVG** | 0.3% | 1.3% | -354 | -17.3% |

KU receives sales forecasts from the Wholesale municipal customers. Compared to the 2011 IRP, the current KU Wholesale sales forecast for the 2014-2018 period (see Table 6.(1)-9) has decreased by an average of 71 GWh per year (3.4 percent). However, this is driven by a lower base line in 2014; the forecasted annual growth rate for sales during this period has increased from 0.6 percent in the 2011 IRP to 1.2 percent in the 2014 IRP. Over the 2014-2028 period, the Wholesale municipal forecast grows at an annual rate of 1.0 percent. This growth rate is higher than the overall KU growth rate. If wholesale sales grew at the rate of overall KU sales, this would result in a 8 MW reduction in the Companies' forecasted peak demand by 2018 and a 19 MW reduction in the Companies peak demand forecast by 2028.

**Table 6.(1)-9**
**Comparison of KU's 2014 and 2011 IRP Wholesale Calendar Sales Forecasts after DSM**

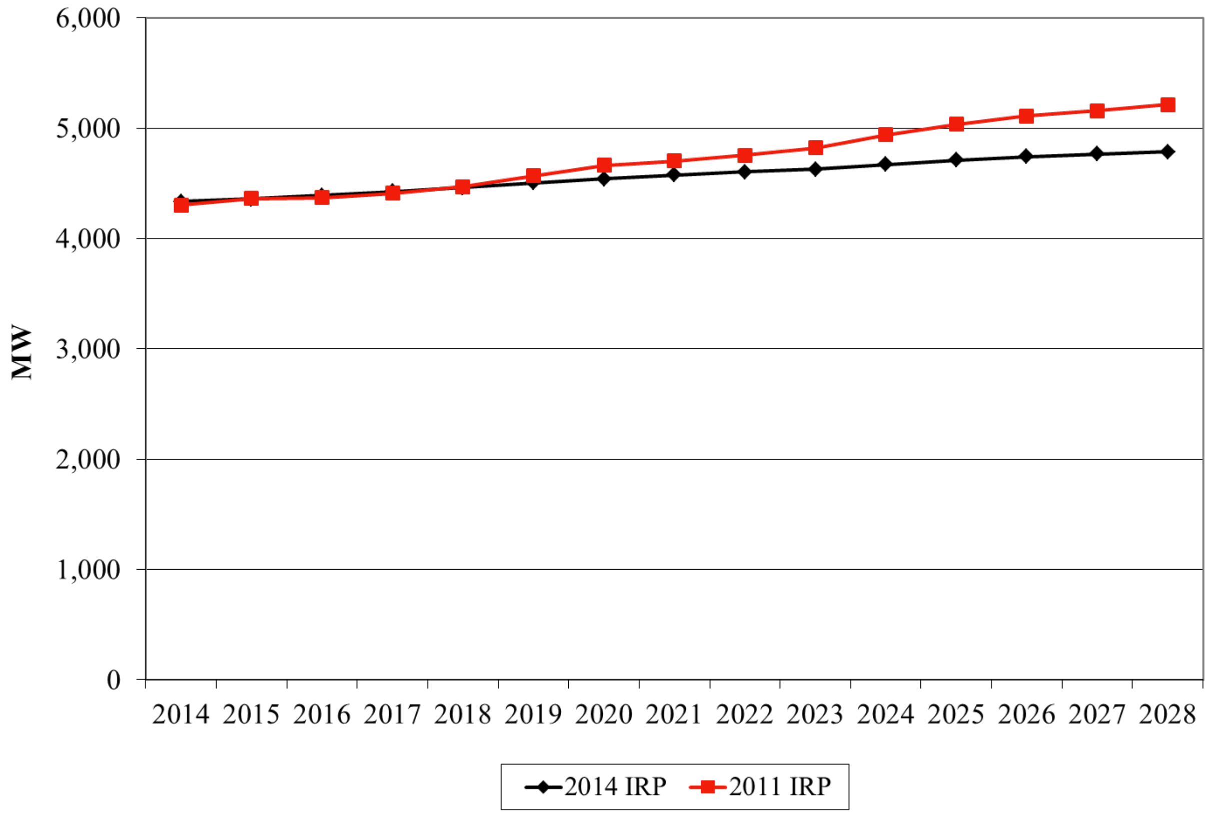
| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| 2014 | 1,969 | 2,066 | -97 | -4.7% |
| 2015 | 1,994 | 2,074 | -80 | -3.8% |
| 2016 | 2,019 | 2,085 | -66 | -3.2% |
| 2017 | 2,041 | 2,100 | -58 | -2.8% |
| 2018 | 2,063 | 2,116 | -53 | -2.5% |
| 2019 | 2,083 | 2,134 | -51 | -2.4% |
| 2020 | 2,103 | 2,148 | -45 | -2.1% |
| 2021 | 2,120 | 2,164 | -44 | -2.0% |
| 2022 | 2,137 | 2,181 | -44 | -2.0% |
| 2023 | 2,155 | 2,200 | -45 | -2.0% |
| 2024 | 2,174 | 2,219 | -45 | -2.0% |
| 2025 | 2,193 | 2,235 | -42 | -1.9% |
| 2026 | 2,213 | 2,255 | -42 | -1.9% |
| 2027 | 2,232 | 2,275 | -43 | -1.9% |
| 2028 | 2,252 | 2,295 | -43 | -1.9% |
| **2014-2018 AVG** | 1.2% | 0.6% | -71 | -3.4% |
| **2014-2028 AVG** | 1.0% | 0.8% | -53 | -2.5% |

Compared to the 2011 IRP, the 2014 IRP KU peak demand forecast is 430 MW lower by 2028. Consistent with the energy requirements forecast, the forecasted annual growth rate for peak demand during this period has decreased from 1.4 percent to 0.7 percent. The change in peak demand for each year is shown in Table 6.(1)-10 and in Graph 6.(1)-10.

**Table 6.(1)-10**
**Comparison of KU’s 2014 and 2011 IRP Peak Demand Forecasts after DSM**

| Year | 2014 IRP (MW) | 2011 IRP (MW) | Change (MW) | % Change |
|---|---|---|---|---|
| **2014** | 4,334 | 4,302 | 32 | 0.7% |
| **2015** | 4,360 | 4,363 | -4 | -0.1% |
| **2016** | 4,391 | 4,368 | 23 | 0.5% |
| **2017** | 4,425 | 4,409 | 16 | 0.4% |
| **2018** | 4,462 | 4,470 | -7 | -0.2% |
| **2019** | 4,505 | 4,567 | -62 | -1.4% |
| **2020** | 4,538 | 4,664 | -126 | -2.7% |
| **2021** | 4,577 | 4,703 | -125 | -2.7% |
| **2022** | 4,602 | 4,753 | -151 | -3.2% |
| **2023** | 4,628 | 4,821 | -193 | -4.0% |
| **2024** | 4,670 | 4,938 | -268 | -5.4% |
| **2025** | 4,709 | 5,036 | -327 | -6.5% |
| **2026** | 4,742 | 5,110 | -369 | -7.2% |
| **2027** | 4,767 | 5,159 | -393 | -7.6% |
| **2028** | 4,784 | 5,214 | -430 | -8.2% |
| **2014-2018 AVG** | 0.7% | 1.0% | 12 | 0.3% |
| **2014-2028 AVG** | 0.7% | 1.4% | -159 | -3.2% |

**Graph 6.(1)-10**
**KU 2014 vs. 2011 IRP Peak Demand Forecast Comparison after DSM (MW)**



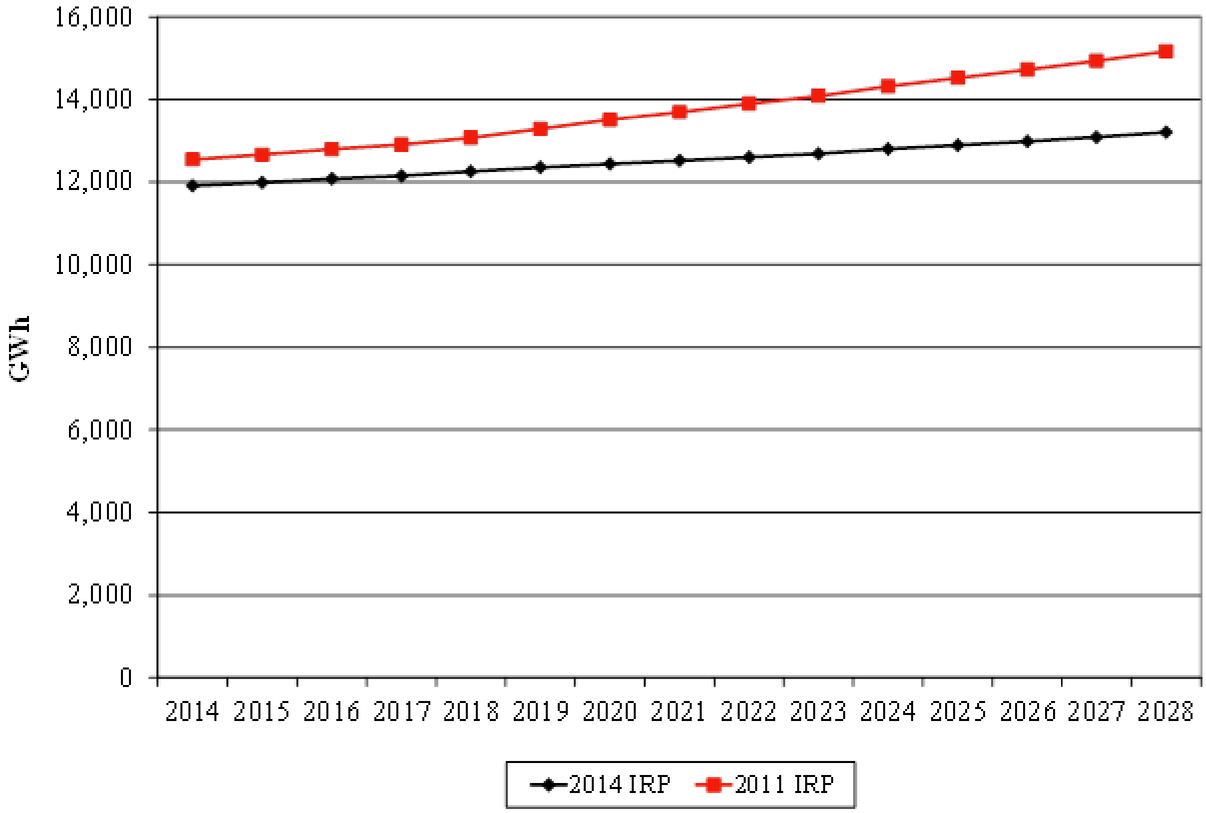

***Louisville Gas and Electric Company***

Compared to the 2011 IRP, the 2014 IRP LG&E sales forecast for the 2014-2018 period has decreased by an average of 717 GWh per year (-5.6 percent). The forecasted growth rate for sales during this period has decreased from an annual growth rate of 1.0 percent in 2011 IRP to 0.7 percent in the 2014 IRP. The change in LG&E sales for each year is shown in Table 6.(1)-11 and in Graph 6.(1)-11. The forecasted growth rate for sales during 2014-2028 has also decreased, from an annual growth rate of 1.4 percent in the 2011 IRP to 0.7 percent in the 2014 IRP. In the 2014 IRP, the downward revisions to the forecast are driven primarily by slower than forecasted economic growth. As the recession ended in 2009, economic activity turned positive but sales growth remained flat. Regression equations take into account relationships between series of data to develop coefficients of variables to forecast the future. The impact of three years of slow or flat growth with positive economic activity indicates a change in the relationship between energy sales and economic indices. As such, the forecast models in the 2014 IRP predict slower growth with slightly positive economic activity.

**Table 6.(1)-11**
**Comparison of LG&E's 2014 and 2011 IRP Calendar Sales Forecasts after DSM**

| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| **2014** | 11,908 | 12,540 | -632 | -5.0% |
| **2015** | 11,985 | 12,659 | -674 | -5.3% |
| **2016** | 12,077 | 12,790 | -713 | -5.6% |
| **2017** | 12,148 | 12,901 | -753 | -5.8% |
| **2018** | 12,253 | 13,068 | -815 | -6.2% |
| **2019** | 12,351 | 13,281 | -930 | -7.0% |
| **2020** | 12,435 | 13,508 | -1,073 | -7.9% |
| **2021** | 12,513 | 13,692 | -1,179 | -8.6% |
| **2022** | 12,596 | 13,901 | -1,304 | -9.4% |
| **2023** | 12,682 | 14,086 | -1,405 | -10.0% |
| **2024** | 12,795 | 14,322 | -1,527 | -10.7% |
| **2025** | 12,886 | 14,524 | -1,637 | -11.3% |
| **2026** | 12,977 | 14,724 | -1,747 | -11.9% |
| **2027** | 13,081 | 14,936 | -1,856 | -12.4% |
| **2028** | 13,201 | 15,168 | -1,968 | -13.0% |
| **2014-2018 AVG** | 0.7% | 1.0% | -717 | -5.6% |
| **2014-2028 AVG** | 0.7% | 1.4% | -1,214 | -8.7% |

**Graph 6.(1)-11**
**LG&E 2014 vs. 2011 IRP Calendar Sales Forecast Comparison after DSM (GWh)**




Compared to the 2011 IRP, the 2014 IRP LG&E Residential sales forecast for the 2014-2018 period (see Table 6.(1)-12) has increased by an average of 33 GWh per year (0.8 percent). The forecasted growth rate for sales during this period has increased from an annual growth rate of 0.9 percent in the 2011 IRP to 1.1 percent in the 2014 IRP, driven by a slight increase in use-per-customer growth. In 2014-2028, the annual growth rate in the 2014 IRP is 1.3 percent compared to 1.5 percent in the 2011 IRP. During this period, the use-per-customer annual growth rate increased from 0.6 percent in the 2011 IRP to 0.7 percent in the 2014 IRP. The annual customer growth rate from 2014-2028 in the 2014 IRP (see Table 6.(1)-13) is 0.3 percent lower than the 2011IRP.

In 2018, LG&E Residential sales are 60 GWh (1.4 percent) higher in the 2014 IRP compared to the 2011 IRP. The difference is due to fewer customers (35 GWh) offset by an increase in use-per-customer (95 GWh).

**Table 6.(1)-12**
**Comparison of LG&E's 2014 and 2011 IRP Residential Calendar Sales Forecasts after DSM**

| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| 2014 | 4,234 | 4,203 | 31 | 0.7% |
| 2015 | 4,252 | 4,235 | 17 | 0.4% |
| 2016 | 4,291 | 4,277 | 14 | 0.3% |
| 2017 | 4,349 | 4,305 | 44 | 1.0% |
| 2018 | 4,418 | 4,358 | 60 | 1.4% |
| 2019 | 4,492 | 4,435 | 57 | 1.3% |
| 2020 | 4,551 | 4,519 | 33 | 0.7% |
| 2021 | 4,613 | 4,583 | 29 | 0.6% |
| 2022 | 4,675 | 4,659 | 16 | 0.3% |
| 2023 | 4,732 | 4,733 | -1 | 0.0% |
| 2024 | 4,811 | 4,831 | -20 | -0.4% |
| 2025 | 4,873 | 4,898 | -25 | -0.5% |
| 2026 | 4,938 | 4,979 | -41 | -0.8% |
| 2027 | 5,008 | 5,063 | -56 | -1.1% |
| 2028 | 5,092 | 5,153 | -61 | -1.2% |
| **2014-2018 AVG** | 1.1% | 0.9% | 33 | 0.8% |
| **2014-2028 AVG** | 1.3% | 1.5% | 6 | 0.2% |

**Table 6.(1)-13**
**Comparison of LG&E's 2014 and 2011 IRP Residential Customer Forecasts**

| Year | 2014 IRP | 2011 IRP | Change | % Change |
|---|---|---|---|---|
| 2014 | 356,974 | 359,848 | (2,874) | -0.8% |
| 2015 | 360,034 | 363,093 | (3,059) | -0.8% |
| 2016 | 363,212 | 366,004 | (2,792) | -0.8% |
| 2017 | 366,369 | 369,245 | (2,876) | -0.8% |
| 2018 | 369,500 | 372,416 | (2,916) | -0.8% |
| 2019 | 372,208 | 375,716 | (3,508) | -0.9% |
| 2020 | 374,598 | 379,229 | (4,632) | -1.2% |
| 2021 | 376,884 | 382,818 | (5,935) | -1.6% |
| 2022 | 378,787 | 386,509 | (7,722) | -2.0% |
| 2023 | 380,384 | 390,036 | (9,652) | -2.5% |
| 2024 | 382,115 | 393,756 | (11,641) | -3.0% |
| 2025 | 383,872 | 397,401 | (13,528) | -3.4% |
| 2026 | 385,638 | 400,956 | (15,317) | -3.8% |
| 2027 | 387,412 | 404,538 | (17,126) | -4.2% |
| 2028 | 389,194 | 408,117 | (18,922) | -4.6% |
| **2014-2018 AVG** | 0.9% | 0.9% | (2,903) | -0.8% |
| **2014-2028 AVG** | 0.6% | 0.9% | (8,167) | -2.1% |

Compared to the 2011 IRP, the 2014 IRP LG&E Commercial sales forecast for the 2014-2018 period (see Table 6.(1)-14) has been reduced by an average of 475 GWh per year (-11.3 percent). The forecasted growth rate for sales during this period has decreased from an annual growth rate of 1.6 percent in the 2011 IRP to 0.1 percent in the 2014 IRP. LG&E Commercial sales have been flat or declining since 2010. Furthermore, sales to large commercial office space have remained stagnant, reinforcing the minimal growth rate in the overall Commercial class. For the smaller commercial customers, the use-per-customer annual growth rate decreased from 1.2 percent in the 2011 IRP to flat in the 2014 IRP for the 2014-2028 period, driven by lower growth in RGSP and Retail Trade Employment indices.

In 2018, LG&E Commercial sales are 600 GWh (13.9 percent) lower in the 2014 IRP compared to the 2011 IRP. Approximately 352 GWh is due to reduced growth in the Commercial sales historical data series, while approximately 248 GWh is due to the lower growth rate for sales due to the inclusion of employment indices as a key forecast input.

**Table 6.(1)-14**
**Comparison of LG&E's 2014 and 2011 IRP Commercial Calendar Sales Forecasts after DSM**

| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| 2014 | 3,695 | 4,046 | -352 | -8.7% |
| 2015 | 3,695 | 4,113 | -418 | -10.2% |
| 2016 | 3,700 | 4,177 | -477 | -11.4% |
| 2017 | 3,701 | 4,231 | -530 | -12.5% |
| 2018 | 3,706 | 4,305 | -600 | -13.9% |
| 2019 | 3,711 | 4,394 | -684 | -15.6% |
| 2020 | 3,718 | 4,488 | -770 | -17.2% |
| 2021 | 3,720 | 4,567 | -847 | -18.5% |
| 2022 | 3,724 | 4,659 | -936 | -20.1% |
| 2023 | 3,729 | 4,743 | -1,015 | -21.4% |
| 2024 | 3,738 | 4,845 | -1,107 | -22.9% |
| 2025 | 3,744 | 4,938 | -1,193 | -24.2% |
| 2026 | 3,749 | 5,017 | -1,268 | -25.3% |
| 2027 | 3,756 | 5,100 | -1,343 | -26.3% |
| 2028 | 3,763 | 5,194 | -1,430 | -27.5% |
| **2014-2018 AVG** | 0.1% | 1.6% | -475 | -11.3% |
| **2014-2028 AVG** | 0.1% | 1.8% | -865 | -18.4% |

Compared to the 2011 IRP, the 2014 IRP LG&E Industrial sales forecast for the 2014-2018 period (see Table 6.(1)-15) has increased by an average of 98 GWh per year (3.5 percent). The forecasted growth rate for sales during this period has increased from an annual growth rate of 0.3 percent in the 2011 IRP to 1.5 percent in the 2014 IRP, driven primarily by higher forecasts for Major Accounts. The Companies receive intelligence from Major Accounts to develop their forecasts. Outlooks for LG&E's major customers have improved since the 2011 IRP. Sales to LG&E's Major Account customers are forecasted to grow at a 1.5% annual rate over the next 5 years, driven by significant growth for two of the larger customers.

**Table 6.(1)-15**
**Comparison of LG&E's 2014 and 2011 IRP Industrial Calendar Sales Forecasts**

| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| 2014 | 2,823 | 2,812 | 12 | 0.4% |
| 2015 | 2,890 | 2,813 | 76 | 2.7% |
| 2016 | 2,946 | 2,821 | 124 | 4.4% |
| 2017 | 2,967 | 2,833 | 134 | 4.7% |
| 2018 | 2,995 | 2,850 | 146 | 5.1% |
| 2019 | 3,012 | 2,868 | 144 | 5.0% |
| 2020 | 3,029 | 2,890 | 140 | 4.8% |
| 2021 | 3,043 | 2,906 | 137 | 4.7% |
| 2022 | 3,059 | 2,918 | 141 | 4.8% |
| 2023 | 3,081 | 2,922 | 159 | 5.5% |
| 2024 | 3,105 | 2,929 | 176 | 6.0% |
| 2025 | 3,126 | 2,943 | 182 | 6.2% |
| 2026 | 3,146 | 2,958 | 188 | 6.3% |
| 2027 | 3,171 | 2,978 | 192 | 6.5% |
| 2028 | 3,197 | 2,996 | 201 | 6.7% |
| **2014-2018 AVG** | 1.5% | 0.3% | 98 | 3.5% |
| **2014-2028 AVG** | 0.9% | 0.5% | 144 | 4.9% |

Compared to the 2011 IRP, the 2014 IRP LG&E Public Authority sales forecast for the 2014-2018 period (see Table 6.(1)-16) has decreased by an average of 374 GWh per year (25 percent). A major customer's change in operation is the primary driver. The forecasted annual growth rate for sales for the 2014-2028 period in the 2014 IRP is flat, compared to a 1.5 percent annual growth rate forecasted in the 2011 IRP.

**Table 6.(1)-16**
**Comparison of LG&E's 2014 and 2011 IRP Public Authority Calendar Sales Forecasts after DSM**

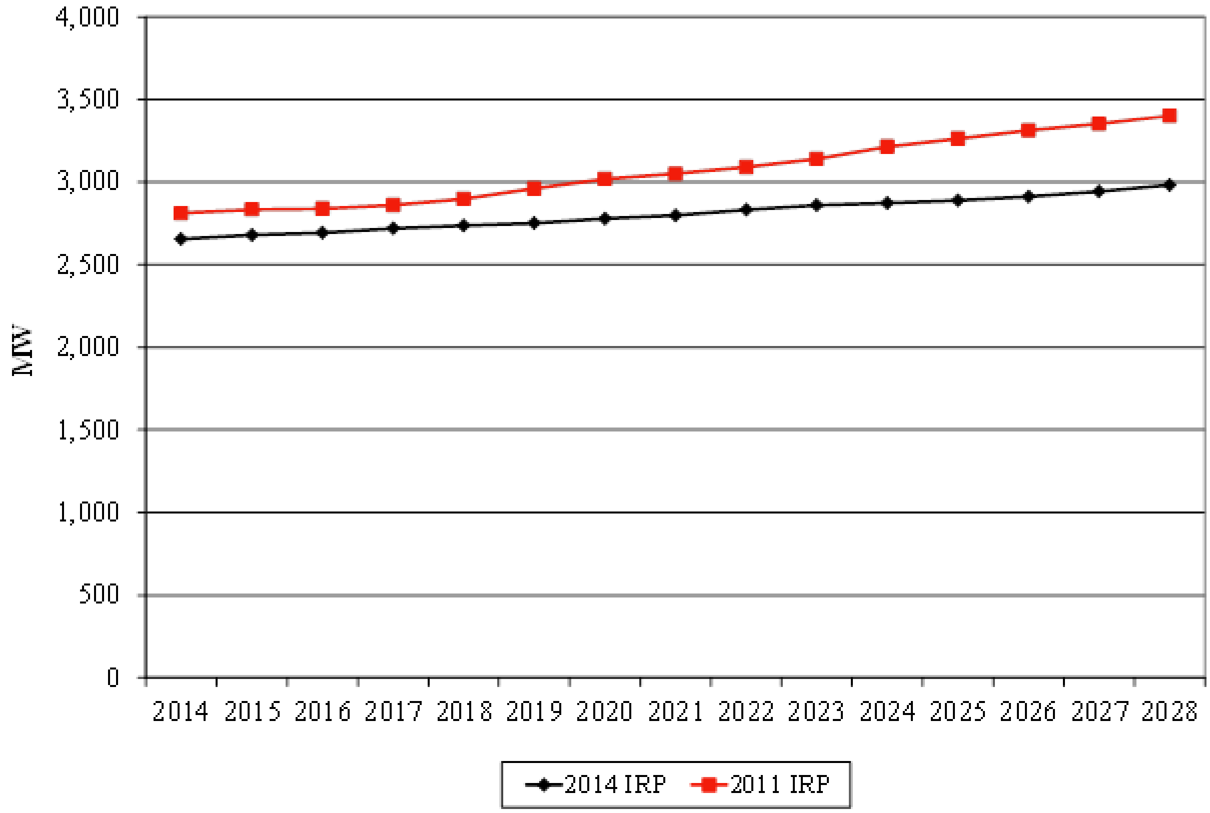
| Year | 2014 IRP (GWh) | 2011 IRP (GWh) | Change (GWh) | % Change |
|---|---|---|---|---|
| 2014 | 1,155 | 1,478 | -323 | -22% |
| 2015 | 1,148 | 1,497 | -349 | -23% |
| 2016 | 1,141 | 1,515 | -374 | -25% |
| 2017 | 1,132 | 1,532 | -400 | -26% |
| 2018 | 1,134 | 1,555 | -421 | -27% |
| 2019 | 1,135 | 1,583 | -447 | -28% |
| 2020 | 1,137 | 1,612 | -475 | -29% |
| 2021 | 1,138 | 1,636 | -499 | -30% |
| 2022 | 1,138 | 1,664 | -526 | -32% |
| 2023 | 1,140 | 1,688 | -548 | -32% |
| 2024 | 1,142 | 1,717 | -576 | -34% |
| 2025 | 1,143 | 1,745 | -602 | -34% |
| 2026 | 1,144 | 1,769 | -625 | -35% |
| 2027 | 1,146 | 1,795 | -649 | -36% |
| 2028 | 1,148 | 1,825 | -677 | -37% |
| **2014-2018 AVG** | -0.5% | 1.3% | -374 | -25% |
| **2014-2028 AVG** | 0.0% | 1.5% | -499 | -30% |

Compared to the 2011 IRP, the 2014 IRP LG&E peak demand forecast is 419 MW lower by 2028. Consistent with the energy requirements forecast, the forecasted annual growth rate for peak demand during the 2014-2028 period has decreased from 1.4 percent to 0.8 percent. The change in peak demand for each year is shown in Table 6.(1)-17 and in Graph 6.(1)-17.

**Table 6.(1)-17**
**Comparison of LG&E's 2014 and 2011 IRP Peak Demand Forecasts after DSM**

| Year | 2014 IRP (MW) | 2011 IRP (MW) | Change (MW) | % Change |
|---|---|---|---|---|
| **2014** | 2,655 | 2,811 | -156 | -5.6% |
| **2015** | 2,679 | 2,833 | -154 | -5.4% |
| **2016** | 2,693 | 2,838 | -145 | -5.1% |
| **2017** | 2,720 | 2,860 | -140 | -4.9% |
| **2018** | 2,737 | 2,898 | -161 | -5.5% |
| **2019** | 2,752 | 2,960 | -209 | -7.1% |
| **2020** | 2,779 | 3,017 | -239 | -7.9% |
| **2021** | 2,798 | 3,050 | -252 | -8.3% |
| **2022** | 2,832 | 3,090 | -258 | -8.4% |
| **2023** | 2,860 | 3,139 | -280 | -8.9% |
| **2024** | 2,873 | 3,213 | -340 | -10.6% |
| **2025** | 2,888 | 3,262 | -373 | -11.4% |
| **2026** | 2,912 | 3,312 | -400 | -12.1% |
| **2027** | 2,943 | 3,351 | -409 | -12.2% |
| **2028** | 2,982 | 3,401 | -419 | -12.3% |
| **2014-2018 AVG** | 0.8% | 0.8% | -151 | -5.3% |
| **2014-2028 AVG** | 0.8% | 1.4% | -262 | -8.4% |

**Graph 6.(1)-17**
**LG&E 2014 vs. 2011 IRP Peak Demand Forecast Comparison after DSM (MW)**




***Recent Sales Trends***

## Combined Company

On a Combined Company basis, weather-normalized calendar sales for 2011-2013 were 3.3 percent to 4.5 percent below the 2011 IRP forecast (see Table 6.(1)-18). Sales grew at a 0.6 percent annual rate from 2011 to 2013, less than half of the 1.3 percent annual growth forecasted for this period in the 2011 IRP. Overall, the 2011 IRP forecasted more robust economic growth for the 2011-2013 period. RGSP was forecasted to grow 2.6 percent annually from 2011 to 2013, 0.8 percent higher than the actual annual growth rate of 1.8 percent during this period.

**Table 6.(1)-18**
**Combined Company Calendar Sales (GWh)**
**Variance to 2011 IRP Forecast**

| Year | 2011 IRP | W/N Actuals | Difference | % Difference |
|---|---|---|---|---|
| 2011 | 33,675 | 32,578 | -1,097 | -3.3% |
| 2012 | 34,113 | 32,991 | -1,122 | -3.3% |
| 2013 | 34,555 | 32,994 | -1,561 | -4.5% |

## Kentucky Utilities Company

KU's weather-normalized calendar sales were lower than the 2011 IRP's forecasted levels between 2011 and 2013 (see Table 6.(1)-19). The 2011 IRP forecast was prepared in early 2010 after an initial "bounce" after the recession ended. However, economic activity was stagnant in the Residential and Commercial sectors over the following three years from 2011 to 2013. From 2011 to 2013, KU sales were mixed as Industrial sales increased by 3.0 percent, but Commercial and Public Authority sales decreased by -2.2 percent and -0.7 percent, respectively. Residential sales grew slightly at 0.3%. Virginia sales decreased by -4.1 percent from 2011 to 2013, primarily due to lower sales to the mining sector. Over the 2011-2013 period, sales to the mining sector for KU, including Virginia, have declined an estimated 671 GWh, or 30 percent, compared to the 2011 IRP forecast. Also see KU Section 7 Table 7.(2)(b) for a further breakdown of recent weather-normalized sales by class.

**Table 6.(1)-19**
**Kentucky Utilities Company Calendar Sales (GWh)**
**Variance to 2011 IRP Forecast**

| Year | 2011 IRP | W/N Actuals | Difference | % Difference |
|---|---|---|---|---|
| 2011 | 21,388 | 21,133 | -254 | -1.2% |
| 2012 | 21,741 | 21,216 | -526 | -2.4% |
| 2013 | 22,083 | 21,262 | -821 | -3.7% |

## Louisville Gas and Electric Company

LG&E's weather-normalized calendar sales were also below the 2011 IRP's forecasted levels between 2011 and 2013 (see Table 6.(1)-20). The 2011 IRP forecast was prepared in early 2010 after an initial "bounce" after the recession ended. However, economic activity was stagnant in the Residential and Commercial sectors over the following three years from 2011 to 2013. Growth from 2010 to 2011 did not materialize as forecasted in the 2011 RIP. However, while starting from a lower base line in 2011, the 2011-2013 annual growth rate for LG&E sales (1.3 percent) was higher than forecasted in the 2011 IRP (0.7 percent). From 2011 to 2013, Residential sales grew by 0.8 percent, Commercial sales grew by 0.5%, while Public Authority sales declined by -2.5 percent. Industrial sales grew by 5.5 percent over the period, impacted primarily by sales to major customers. Also see LG&E Table 7.(2)(b) for a breakdown of recent weather-normalized sales by class.

**Table 6.(1)-20**
**Louisville Gas and Electric Company Calendar Sales (GWh)**
**Variance to 2011 IRP Forecast**

| Year | 2011 IRP | W/N Actuals | Difference | % Difference |
|---|---|---|---|---|
| 2011 | 12,287 | 11,444 | -843 | -6.9% |
| 2012 | 12,372 | 11,775 | -597 | -4.8% |
| 2013 | 12,471 | 11,732 | -739 | -5.9% |

***Updates to Weather Assumptions***

For both KU and LG&E, the most recent 20-year average of heating degree days (HDDs) and cooling degree days (CDDs) is used to represent the weather conditions that are likely to be experienced on average over the forecast horizon. Average weather in the 2014 IRP forecast is based on the weather in the 20-year period ending in 2012; the weather in the 2011 IRP was based on the weather in the 20-year period ending in 2009. NOAA weather data for Louisville and Lexington, Kentucky, as well as Bristol, Tennessee, are used to represent the weather in the LG&E, KU and ODP service territories, respectively. HDDs and CDDs use a 65 degree Fahrenheit base.

Table 6.(1)-22 compares the annual CDDs and HDDs from the 2014 IRP and the 2011 IRP. The differences are minor: slightly cooler summers and warmer winters in the KU service territory and slightly warmer summers and winters in the LG&E service territory. These updates do not contribute to material changes in the forecast for energy and peak demand.

**Table 6.(1)-22**
**Comparison of Annual CDDs and HDDs**

| | KU | | LG&E | | ODP | |
|---|---|---|---|---|---|---|
| | **2014 IRP** | **2011 IRP** | **2014 IRP** | **2011 IRP** | **2014 IRP** | **2011 IRP** |
| CDDs | 1,196 | 1,208 | 1,462 | 1,446 | 1,051 | 1,047 |
| HDDs | 4,565 | 4,574 | 4,183 | 4,261 | 4,208 | 4,145 |

**Service Territory Economic and Demographic Forecasts**

In both the 2014 IRP and 2011 IRP, service-territory-level economic and demographic forecasts were developed based on county-level forecasts provided by IHS Global Insight. The service-territory-level forecasts were consistent with the national-level forecasts from Global Insight.

The following is a summary of changes in key assumptions made in Global Insight's 2013 Long-Term Macro Forecast and Population and Household Forecast for Kentucky, used by the Companies as inputs to the energy sales forecast in the 2014 IRP. Copies of the economic and demographic forecasts are attached as part of the Technical Appendix in Volume II.

- In the 2014 IRP, Kentucky Real Gross State Product (RGSP) is forecasted to grow at an annual rate of2.1 percent from 2014-2028 versus 2.2 percent for the same period in the 2011 IRP. Growth is forecasted to be relatively stronger in the near-term. In the 2014 IRP, RGSP is forecasted to grow at an annual rate of 2.7 percent from 2014-2018 compared to 2.4 percent in the 2011 IRP. However, in the 2019-2028 period, RGSP is forecasted to slow to a 1.9 percent annual growth rate in the 2014 IRP compared to 2.0 percent in the 2011 IRP.
- Kentucky Real Personal Income is forecasted to grow 2.5 percent annually from 2014-2028 compared to the 2.9 percent growth rate in the 2011 IRP. The level of

Real Personal Income in 2014 is also forecasted to be about 4.5 percent lower, or about 1.5 years of growth, than in the 2011 IRP.

- The Kentucky Industrial Production Index (IPI) is forecasted to grow at a 2.6 percent annual rate from 2014-2018, only slightly lower than the 2.7 percent annual rate used in the 2011 IRP. However, the absolute level of the IPI forecasted for 2014 is now 14 percent lower than in the 2011 IRP. The 2011 IRP forecasted level for 2014 is now forecasted to be reached in 2019.
- The Kentucky Households growth of 0.8 percent from 2014-2028 is consistent with the forecasted growth used in the 2011 IRP. However, the 2014 forecast for number of households is 2.3 percent lower than what was forecasted for 2014 in the 2011 IRP, or about two years of typically forecasted growth.

***Changes in Methodology***

Minor changes in forecasting methodology were incorporated in the 2014 IRP forecasts. These changes were made as part of on-going processes to increase the accuracy of the energy forecast. The following changes were made:

- In the 2011 IRP, the company used class-specific load profiles to develop its hourly demand forecasts in an effort to better reflect demand-side management programs that impact the load profile of specific classes. In the 2014 IRP, the company further improved this process by using historical hourly shapes by company, month, and day of week with different weather ranges to better reflect load shapes for different temperature ranges.
- In the 2011 IRP, home appliance saturation surveys of both LG&E and KU customers provided responses that were used to develop assumptions for the

residential forecasting models. In the 2014 IRP, the home appliance saturation surveys continued to be used in the residential forecasting models. In addition, commercial end-use surveys were conducted and used to develop assumptions for small commercial forecasting models.

- RGSP was used as the primary economic driver of the small commercial sales forecast in the 2011 IRP. In the 2014 IRP, the Companies also used Kentucky retail employment as a key driver in the small commercial forecast.
- In the 2014 IRP, the KU Wholesale forecast used the forecasts provided by the twelve municipal customers. In the 2011 IRP, the Companies forecasted the Wholesale municipal customers with input from the municipal forecasts received and a function of households and weather.

## DEMAND-SIDE MANAGEMENT

### DSM Revisions in 2014 IRP

The 2014 IRP uses a lower amount of peak DSM compared to the 2011 IRP, based on results from existing DSM programs. Table 6.(1)-23 compares the cumulative peak DSM reductions in the most recent DSM filing, the 2011 IRP, and the 2014 IRP.

**Table 6.(1)-23**
**Demand Side Management Reductions (MW)**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak DSM in (2014-2018) DSM Filing | 340 | 388 | 425 | 463 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Peak DSM in 2011 IRP | 344 | 388 | 429 | 469 | 480 | 480 | 480 | 480 | 480 | 480 | 480 | 480 | 480 | 480 | 480 |
| Peak DSM in 2014 IRP | 306 | 336 | 365 | 394 | 423 | 406 | 406 | 406 | 406 | 406 | 406 | 406 | 406 | 406 | 406 |

The 2014 IRP peak DSM reductions are lower compared to the 2011 IRP due to customers electing to install higher efficiency AC units, thus reducing the amount of peak energy reduction achieved per load control device in the DSM Load Management/Demand Conservation program.

The remaining difference between the DSM reductions in the 2014 DSM filing and the 2014 IRP is related to adjustments to ensure that the IRP DSM reductions are properly calibrated to the peak summer demand hour. The 2014 DSM filing and prior DSM filings present DSM reductions based on customer participation levels at yearend, while the IRP load forecasts use a mid-year convention to correspond to summer peak load conditions. Thus, the IRP DSM reductions are lower based on the mid-year convention.

## RELIABILITY CRITERIA

In the 2014 IRP, the Companies continue to target a minimum 16 percent reserve margin for the purpose of developing resource expansion plans. The Companies' 2014 Reserve Margin Study is contained in Volume III, Technical Appendix.

## UPGRADES TO HYDROELECTRIC STATIONS

### Ohio Falls

Since the 2011 IRP, LG&E has continued with Phase 3 of the project to rehabilitate the eight units at the Ohio Falls Station. Rehabilitation of each unit will result in a nameplate capacity rating increase from 10 MW to 12.58 MW per unit. However, the Ohio Falls Station is a run-of-river facility that is subject to river flow. This project is expected to increase the planned summer capacity of this station from 48 MW to 64 MW. Rehabilitation of Ohio Falls Units 3, 5, 6, 7 has already been completed. Rehabilitation of Ohio Falls Units 3 and 5 have been completed since 2011.

### Dix Dam

Since the 2011 IRP, KU has also completed a project to overhaul the remaining two units at the Dix Dam Hydroelectric Station. The project involved rewinding the generators, refurbishing the turbines, and replacing the controls. Additionally, Unit 2 had the turbine inlet valve refurbished due to the vintage of the valve. The overhauls to Unit 1 and 2 were completed in 2013 and 2012, respectively, which increased the capacity of each unit from 8 to 10 MW, for a total increase of 4 MW at the current lake level target range.

## TRANSMISSION SYSTEM OPERATOR

During July 2006, the KPSC and FERC authorized the Companies to exit MISO. Upon exiting MISO, the Southwest Power Pool ("SPP") served as the Independent Transmission Operator ("ITO") and TVA served as the reliability coordinator for the Companies. SPP and the Companies terminated the ITO contract, effective August 31, 2012. Prior to this termination, the Companies entered into a new ITO contract with TranServ International, Inc. ("TranServ") for TranServ to perform the role of the ITO, effective September 1, 2012. The initial term of the contract with TranServ is three years, with two automatic one-year renewals.

## RESERVE SHARING GROUP

In May 2013, Eastern Kentucky Power Cooperative ("EKPC") exited the reserve sharing group ("RSG") that Tennessee Valley Authority ("TVA") and the Companies had created after the Companies' exit of MISO in 2006. This increased the Companies' contingency reserve requirement from 238 MW to 253 MW.

## RESEARCH AND DEVELOPMENT

### FutureGen

In the 2011 IRP, it was discussed that the DOE declined to renew the agreement with the FutureGen Industrial Alliance and instead, executed a new FutureGen 2.0 agreement with Ameren to repower an existing pulverized coal unit using Babcock and Wilcox oxy-combustion technology. On September 28, 2010 the FutureGen Industrial Alliance signed a new agreement with the Department of Energy to build the FutureGen 2.0 $CO_2$ pipeline network and $CO_2$ storage site. Since the Companies joined the FutureGen Alliance, the Environmental Protection Agency has issued numerous stricter regulations impacting the Companies' generation facilities and the Companies' primary focus has shifted to the more than $3 billion in construction projects in order to comply with the federal environmental mandates. The Companies continue to support the vision embodied in the FutureGen program, but the Companies had to reprioritize and dedicate the Companies' resources to meet the demands caused by these large construction projects.

**Greenhouse Gas Research**

In the 2011 IRP, it was mentioned that the Companies were supporting efforts at the University of Kentucky's Center for Applied Energy Research ("CAER"), the University of Texas at Austin, and 3H Company. The study with 3H Company has concluded with a final report expected in 2014. The efforts with the University of Texas at Austin have changed in scope and cost ($75,000/year) to include both modeling efforts for $CO_2$ capture along with a pilot testing facility. The research being conducted at CAER through the Carbon Management Research Group (CMRG) has grown with the addition of a $14.5 million DOE grant in 2011. The grant allows the CMRG to leverage the Companies contribution and install a carbon capture slip-stream pilot demonstration system at the Companies' E.W. Brown plant. The process will take a small portion of the flue gas and use an amine based solvent to capture $CO_2$.

The Companies continue to support research with the Electric Power Research Institute ("EPRI") in their "Carbon Capture and Storage" program along with specific projects to answer many unanswered questions regarding the feasibility of the technology.

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

**Other Generation Resource Research**

With the increased pressures on coal generation along with the reduced cost of natural gas and declining cost of renewable and distributed generation, the Companies are also supporting research efforts in natural gas combined cycle generation and renewable/distributed technologies. Vendors are providing new designs for combined cycle natural gas power plants every year that are not vetted in the field and their operations are transitioning from peak load units to possible base load units depending on the cost of natural gas. The Companies support research efforts within EPRI through their "Combined Cycle Turbomachinery" and "Heat Recovery Steam Generator and Balance of Plant" programs to better understand the technologies entering the market along with the ensuring the plants that are built are operated in a safe and cost effective manner.

The use of renewable and distributed energy resources are on the rise but generally are not currently economical in Kentucky. With the downward trend in some of their cost projections however, the technology development must be tracked (i.e. solar). As the economics improve and deployment of these technologies grows, the impacts on the reliability and safety of the grid need to be considered. The Companies are staying abreast of development advances through support of EPRI's renewable programs including "Economics and Technology Assessments", "Solar", and "Biomass" along with their "Energy Storage" program.

## ENVIRONMENTAL REGULATIONS

As an update to the 2011 IRP, there have been a large amount of significant changes in the environmental regulation arena. These regulations are discussed in detail in Sections 8.(5)(b) and 8.(5)(f).

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

As an update to the 2011 IRP, the impacts of cooling water intakes on fish populations were further studied. EPA is currently drafting a revised 316(b) regulation which is anticipated to be finalized in early 2014. The Companies expect both industry and environmental groups will utilize the court system to again challenge the new rule and possibly delay implementation deadlines. The regulation will address both impingement and entrainment impacts for aquatic species, thus possibly affecting all Company intake water facilities, including those already equipped with closed cycle cooling (cooling towers).

### Clean Water Act – Effluent Limitation Guidelines

As an update to the 2011 IRP, EPA further studied the issue and in 2009, EPA determined that it would revise the steam-electric industry effluent standards. In June 2010, EPA issued a very detailed questionnaire to over 500 utilities across the nation that was aimed at assisting EPA in revising the standards. Based on the depth of the questionnaire, it is anticipated that it will take EPA several years to digest the information. Draft regulations were proposed by EPA in May 2013 with final promulgation due in May 2014; but, that timeframe may be extended to 2015. Those potential regulations could require capital investments for process water treatment facilities within the time period of this IRP document.

**Clean Air Interstate Rule/ Cross-State Air Pollution Rule**

As an update to the 2011 IRP, the Clean Air Interstate Rule ("CAIR") $NO_x$ reduction program began in 2009 and the $SO_2$ program began in 2010 and included a Phase II beginning in 2015 to further reduce $NO_x$ and $SO_2$ allowances and associated emissions that can be transported across state lines. However, the CAIR was remanded back to EPA on July 11, 2008 by the D.C. Circuit Court for further reconsideration.

The original proposed efforts by EPA to replace CAIR were referred to as the Clean Air Transport Rule ("CATR"). On August 6, 2011, the EPA published in the federal register the final version under the title of Cross-State Air Pollution Rule ("CSAPR"). The CSAPR included limitations on interstate trading and prescribed a new trading program for $SO_2$ allowances that did not allow for previously banked allowances to be used in this new program. The reductions prescribed by the CSAPR were similar for the Companies as CAIR reductions. The CSAPR included a two-phase program for both $NO_x$ and $SO_2$, with less reduction of $NO_x$ required by the Companies by 2012 and somewhat less reduction required for 2014 and beyond. The reduction under the CSAPR for $SO_2$ compared with the CAIR would be somewhat less in 2012 and somewhat more in 2014 and beyond.

Due to subsequent petitions against the CSAPR primarily concerning issues with EPA methodology of allocations for alleviating states' contributions to downwind Ozone and $PM_{2.5}$ issues, the CSAPR was stayed by the D.C. Circuit court in December of 2011. On August 12, 2012 the D.C. Court of Appeals vacated the CSAPR, remanded it to EPA for rewriting, and ordered EPA to continue to administer the CAIR rule until the rewrite is complete and promulgated.

The EPA and a number of environmental groups, states, and others petitioned the D.C. Circuit Court of Appeals for a full court re-hearing of the CSAPR. The petition was denied on

August 12, 2012. A similar appeal was then filed with the Supreme Court. In June of 2013, the Supreme Court agreed to rehear arguments to re-instate the CSAPR. The initial arguments were heard in December of 2013 with a final decision expected in the spring of 2014. The CAIR rule will continue to be implemented until a decision by the Supreme Court directs otherwise or a separate action by EPA to address transport of emissions affecting downstream NAAQS attainment is promulgated.

**Hazardous Air Pollutant Regulations**

Since the 2011 IRP, the EPA developed final rules to establish National Emission Standards for Hazardous Air Pollutants for the coal- and oil- fired electric utility industry. The Mercury Air Toxics Standards ("MATS") rule was published in the Federal Register on February 16, 2012 that set emission limits for mercury, acid gases, toxic metals, and organics including dioxins and furans based on the maximum achievable control technology ("MACT") for the industry. The emission standards within this rule have instigated multiple installations of pulse jet fabric filters for additional control of particulate matter containing trace amounts of certain toxic metals and shutdown of older coal-fired generation, some of which is to be replaced with new natural gas combined cycle generation. The compliance date is April 16, 2015; however, the rule allows the permitting authority to grant up to a one year extension based on submittal of a justifiable request.

To meet emissions compliance limitations with the MATS rule, the Companies are in the process of installing pulse jet fabric filter systems (PJFF) on all coal-fired units with the exception of Trimble County Unit 2 and E.W. Brown Units 1 and 2. The Trimble County Unit 2 currently includes a PJFF as original equipment and E.W. Brown Units 1 and 2 will utilize additives to assist with mercury removal and average their emissions with the emissions of E.W.

Brown Unit 3. Dry sorbent injection systems will be installed on each unit that receives a PJFF system for the purpose of protecting the materials of construction. Powdered activated carbon injection systems will be added to enhance removal of mercury emissions. Emissions of mercury and acid gases will further be reduced at all coal-fired units with the existing wet flue gas desulfurization (WFGD) systems and with new WFGD systems at Mill Creek Units 1 through 4.

**National Ambient Air Quality Standards**

***$SO_2$***

As an update to the 2011 IRP, EPA has set the implementation process and timeline relative to the one-hour standard published as a final rule in June of 2010. The 2010 NAAQS for $SO_2$ is a 1-hour primary (i.e., health based) $SO_2$ standard of 75 parts per billion ("ppb"), based on the three year average of the fourth highest of the 1-hour maximum concentrations. Kentucky made their $SO_2$ attainment recommendations in January 2013 and the initial non-attainment designations approved by EPA were published in the Federal Register in October, 2013. The historical 3-hour ambient monitoring $SO_2$ data (2009 – 2011) at the Watson Lane monitor location in Jefferson County was utilized by the state and local air agencies to designate the area adjacent to the Mill Creek Generating Station in non-attainment of the new standard. Kentucky must submit a state implementation plan ("SIP") that will contain enforceable emission limitations or control measures on sources contributing to non-attainment by April, 2015 in order to achieve attainment by October, 2018. The new FGDs currently underway at the Mill Creek facility should allow for emission levels to be achieved as needed for compliance.

***$NO_2$***

The status of the NAAQS for $NO_2$ has not changed since the 2011 IRP in which it was noted that EPA published a final rule which revised the primary NAAQS for $NO_2$ on February 9, 2010. It became effective on April 12, 2010. EPA adopted a new 1-hour standard of 100 ppb and retained the existing annual average standard of 53 ppb. Based on existing air quality data in Kentucky, all areas are currently well below these standards. However, the new rule stipulated the establishment of additional new air quality monitor locations. Emphasis is to be placed on locating these monitors near major roadways in large cities where the highest concentrations are expected; but additional monitors to represent community-wide air quality may also be required in large cities. The additional monitors are to be installed in phases between 2014 and 2017 and will be utilized in development of future revisions to the $NO_2$ standard.

EPA is also planning to evaluate whether changes to Prevention of Significant Deterioration ("PSD") air quality increments are needed. If so, this could place further limits on the allowable amount of increased emissions from a new or modified source.

Kentucky must incorporate this new NAAQS into its SIP. Additionally, the SIP must contain a plan to bring any non-attainment areas into attainment with the standard by June 2017.

***Ozone***

As an update to the 2011 IRP, Jefferson County was designated "moderate" non-attainment with the 2008 NAAQS for ozone of 0.075 parts per million ("ppm"). With record high temperatures during the summer of 2012, the Ozone standard remains in non-attainment with the inclusion of 2012 data. However, there were no exceedances monitored in Jefferson County in 2013. With consideration of the shutdown of three coal-fired units at the Cane Run Station in 2015 and additionally reductions of coal-fired generation (retirement of two coal-fired units) that has occurred at the Duke Energy-Gallagher Station in New Albany, Indiana, the Ozone non-attainment in Jefferson County is expected to be satisfactorily mitigated. As a result, additional reductions on the Companies' units to meet the 2008 Ozone standard are not expected. On January 7, 2010, EPA proposed an even lower primary ozone standard within a range of 0.060 and 0.070 ppm measured over eight hours. At the same time, EPA proposed a new seasonal secondary ozone standard in the range of 7 to 15 ppm. EPA withdrew their proposal due to insufficient data and is planning to propose a revision in 2014 that will likely become final in 2015. Once the final standard is promulgated, Kentucky will have up to three years to establish attainment status designations. Kentucky will then have one year to submit a SIP incorporating the new NAAQS and plans for bringing all areas into attainment with the new standard. EPA will then have one year to approve Kentucky's SIP submittal and typically, non-attainment areas will have at least three years (approximately until 2022) to obtain attainment status following EPA's approval.

***PM / $PM_{2.5}$***

As an update to the 2011 IRP, an audit was conducted by the Kentucky Division for Air Quality ("KyDAQ") in 2013 that found data quality issues with the $PM_{2.5}$ monitors operated by the Louisville Metropolitan Air Pollution Control District ("LMAPCD"). Although Jefferson County is still currently classified as non-attainment for the 1997 24-hr standard, the KyDAQ has recommended a status of attainment/unclassifiable based on valid 2011 to 2013 data and the general downward trend of ozone. Additionally, KyDAQ has recommended the use of data from monitors located near Jefferson County located in southern Indiana in support of attainment status. At this time, that process is still under review by EPA.

In addition, the EPA promulgated in December of 2012 a new NAAQS for $PM_{2.5}$ that lowered the 24-hour standard from 15 $\mu g/m^3$ to 12 $\mu g/m^3$. Based on monitoring data in Kentucky for 2010 – 2011, Jefferson County would not meet the lowered standard. Attainment designations have not been established at this time. However, as a result of the shutdown of coal-fired generation at the Cane Run facility in 2014 and the installation of pulse jet fabric filters on the Mill Creek coal-fired units by 2016, issues with attainment status are expected to be mitigated.

**Greenhouse Gases**

Since the 2011 IRP, President Obama announced his "Climate Action Plan" on June 25, 2013 which laid out a timeline and targets for regulatory development to reduce greenhouse gas ("GHG") emissions. In response, EPA issued a proposed new source performance standard ("NSPS") for GHG emissions from new fossil fuel fired electric generation sources. The proposal was published in the Federal Register on January 8, 2014 and establishes the effective date of applicability for the specific standards limiting $CO_2$ emissions from new fossil fuel fired electric generating facilities including coal fired, natural gas fired (if greater than 1/3 of the maximum potential generation is used on the grid), and integrated gas combined cycle ("IGCC") units. The currently proposed GHG NSPS establishes partial carbon collection and storage ("PCCS") as the best system of emission reduction. The proposal is expected to be promulgated by January of 2015.

With promulgation in of the GHG "Tailoring Rule" in March of 2010, effective July 2011 any new source with maximum potential emissions of $CO_2e$ greater than 100,000 tons per year or a modification to a new source that is evaluated to cause an increase in $CO_2e$ greater than 75,000 tons per year will trigger Prevention of Significant Deterioration ("PSD"). If triggered, the source must include an analysis of best available control technology ("BACT") during permitting activities. At this time, until the proposed GHG NSPS is promulgated, energy efficiency at an emission source is considered BACT. However, the currently proposed GHG NSPS establishes partial carbon collection and storage ("PCCS") as the best system of emission reduction for new units. If the proposed GHG NSPS is promulgated as is currently written, PCCS will become BACT.

Additionally, EPA is targeted to propose regulations by June of 2014 for GHG NSPS applicable to existing fossil fuel fired electric generating units. President Obama's Climate Action Plan targeted 17% economy-wide reductions from 2005 emissions by 2020. Until more information is provided, the potential impact of these rules is uncertain. The Companies will continue to monitor this issue.

**Coal Combustion Residuals**

As an update to the 2011 IRP, EPA has begun to investigate tightening regulation of coal combustion residuals ("CCR") from the electric utility industry. Within the next few years, regulatory changes are expected in the permitting and management practices for CCR from coal ash and flue gas desulphurization ("FGD") systems whether they are managed in ash treatment basins (ash ponds) or landfills.

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

EPA has not yet selected a final option and is not likely to do so before December 2014. When published, the regulation will likely have a five year implementation window. This means that existing CCR management facilities would require upgrade or closure.

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# 7. LOAD FORECASTS

## Kentucky Utilities Company

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

The data submissions in the following subsections conform to the specifications provided in Section 7.(1) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible. Energy and demand forecasts reflect the impact of the Companies' Demand Side Management (DSM) programs.

### 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. Energy and demand forecasts reflect the impact of the Companies' Demand Side Management (DSM) programs.

**7.(2)(a) KU Average Number of Customers by Class, 2009-2013**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Residential** | 420,028 | 422,858 | 421,253 | 417,748 | 420,223 |
| **Commercial** | 80,357 | 81,223 | 80,166 | 80,509 | 80,252 |
| **Industrial** | 1,957 | 2,172 | 2,281 | 2,547 | 2,734 |
| **Public Authority*** | 7,162 | 7,193 | 6,660 | 7,428 | 7,579 |
| **Public Street and Highway Lighting** | 1,376 | 1,381 | 1,230 | 1,307 | 1,353 |
| **Virginia Retail** | 29,738 | 29,624 | 29,249 | 28,922 | 28,742 |
| **Req. Sales for Resale** | 12 | 12 | 12 | 12 | 12 |
| **Total Customers** | 540,630 | 544,463 | 540,851 | 538,473 | 540,895 |

* Includes Municipal Pumping

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

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **SYSTEM BILLED SALES:** | | | | | |
| **Recorded** | 20,011 | 21,921 | 21,220 | 20,949 | 21,206 |
| **Weather Normalized** | 20,206 | 21,291 | 21,013 | 21,120 | 21,128 |
| **SYSTEM USED SALES:** | | | | | |
| **Recorded** | 20,260 | 21,938 | 21,163 | 20,955 | 21,269 |
| **Weather Normalized** | 20,398 | 21,234 | 21,133 | 21,216 | 21,262 |
| **ENERGY REQUIREMENTS:** | | | | | |
| **Recorded** | 21,476 | 23,467 | 22,179 | 22,177 | 22,602 |
| **Weather Normalized** | 21,613 | 22,764 | 22,149 | 22,438 | 22,595 |
| **RECORDED SALES BY CLASS:** | | | | | |
| **Residential** | 6,165 | 6,729 | 6,146 | 5,930 | 6,195 |
| **Commercial** | 4,319 | 4,365 | 4,107 | 3,970 | 3,906 |
| **Industrial** | 5,455 | 6,245 | 6,450 | 6,710 | 6,843 |
| **Lighting** | 52 | 54 | 49 | 43 | 41 |
| **Public Authorities** | 1,510 | 1,581 | 1,569 | 1,556 | 1,542 |
| **Requirement Sales for Resale** | 1,848 | 2,002 | 1,906 | 1,886 | 1,880 |
| | --------- | --------- | --------- | --------- | --------- |
| **KENTUCKY Retail** | 19,349 | 20,976 | 20,227 | 20,095 | 20,407 |

| | | | | | |
|---|---|---|---|---|---|
| **VIRGINIA Retail** | 911 | 962 | 936 | 860 | 862 |
| **SYSTEM LOSSES** | 1,191 | 1,507 | 994 | 1,201 | 1,311 |
| **Utility Use** | 25 | 23 | 22 | 21 | 22 |
| **ENERGY REQUIREMENTS** | 21,476 | 23,467 | 22,179 | 22,177 | 22,602 |
| **WEATHER NORMALIZED SALES BY CLASS:** | | | | | |
| **Residential** | 6,238 | 6,290 | 6,146 | 6,129 | 6,180 |
| **Commercial** | 4,362 | 4,241 | 4,086 | 3,992 | 3,908 |
| **Industrial** | 5,460 | 6,210 | 6,448 | 6,710 | 6,844 |
| **Lighting** | 52 | 54 | 49 | 43 | 41 |
| **Public Authorities** | 1,517 | 1,550 | 1,565 | 1,561 | 1,543 |
| **Requirement Sales for Resale** | 1,858 | 1,946 | 1,897 | 1,894 | 1,879 |
| **VIRGINIA Retail** | 912 | 909 | 943 | 886 | 867 |

**7.(2)(c) KU Coincident Peak Demands (MW)**

| | **2009** | **2010** | **2011** | **2012** | **2013** |
|---|---|---|---|---|---|
| **SUMMER Actual** | 3,888 | 4,323 | 4,102 | 4,138 | 3,919 |
| | **2008/2009** | **2009/2010** | **2010/2011** | **2011/2012** | **2012/2013** |
| **WINTER Actual** | 4,640 | 4,344 | 4,517 | 4,014 | 4,153 |

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

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Energy Sales (GWh)** | 18,941 | 20,451 | 19,591 | 19,457 | 19,749 |
| **Coincident Peak Demand (MW)** | 3,829 | 4,253 | 4,026 | 4,065 | 3,843 |

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

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Energy Sales (GWh)** | 408 | 525 | 636 | 638 | 658 |
| **Coincident Peak Demand (MW)** | 59 | 70 | 76 | 73 | 76 |

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

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Annual Energy Loss** | 1,191 | 1,507 | 994 | 1,201 | 1,311 |
| **Loss Percent of Energy Requirements** | 5.9% | 6.9% | 4.7% | 5.7% | 6.2% |

### 7.(2)(g) Impact of Existing Demand Side Programs (cumulative for KU and LG&E)

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Energy Savings (GWh)** | 89 | 206 | 362 | 483 | 671 |
| **Demand Savings (MW)** | 154 | 183 | 225 | 271 | 331 |

### 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. 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)**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Residential** | 14,678 | 15,913 | 14,590 | 14,195 | 14,742 |
| **Commercial** | 53,748 | 53,741 | 51,231 | 49,311 | 48,672 |
| **Industrial** | 2,787,430 | 2,875,230 | 2,827,707 | 2,634,472 | 2,502,926 |
| **Public Authority** | 210,835 | 219,797 | 235,586 | 209,478 | 203,457 |
| **Utility Use & Other** | 37,791 | 39,102 | 39,837 | 32,900 | 30,303 |

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

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Total Residential** | 32% | 32% | 31% | 29% | 30% |
| **Commercial** | 21% | 20% | 19% | 19% | 18% |
| **Industrial** | 27% | 28% | 30% | 32% | 32% |
| **Public Authority** | 7% | 7% | 7% | 7% | 7% |
| **Utility Use and Other** | 0% | 0% | 0% | 0% | 0% |
| **Virginia Retail** | 4% | 4% | 4% | 4% | 4% |
| **Req. Sales for Resale** | 9% | 9% | 9% | 9% | 9% |
| **Total Company** | 100% | 100% | 100% | 100% | 100% |

***KU Kentucky Retail Residential Sales***

Changes in KU's Kentucky retail residential sales are driven by changes in both average use-per-customer and incremental customer growth. Since 2009, the total number of residential customers has remained relatively flat, while weather-normalized sales decreased at an annual growth rate of -0.2 percent.

***KU Kentucky Retail Commercial Energy Sales***

KU's Kentucky retail commercial class has little growth in number of customers and declining use-per-customer. From 2009 to 2013, the total number of customers was virtually flat, while weather-normalized sales decreased at an annual rate of 2.7 percent. Customer classification changes from the commercial to the industrial revenue class accounts for part of the diminished growth in the commercial class. Most of the classification changes took place during 2011. By late 2011, 137 customers with total annual sales estimated at 138 GWh had been reclassified from the commercial class to the industrial class.

***KU Kentucky Retail Industrial Energy Sales***

Since 2009, the number of customers in the industrial class increased at a compound annual growth rate of 8.7 percent. Total sales to this class increased by a compound annual growth rate of 5.8 percent. This growth was primarily the result of the growth in sales to a small number of large industrial customers, as well as the reclassification of some commercial customers to the industrial class.

***KU Virginia Energy Sales***

Virginia sales experienced a slight decline at an annual rate of 1.4 percent since 2009. The total number of customers declined and the corresponding weather-normalized sales declined at an annual rate of 1.3 percent over the 2009-2013 period.

***KU Wholesale Energy Sales***

Wholesale (municipal) weather-normalized sales have remained flat since 2009. Sales to the wholesale sector consist of 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 after DSM* (GWh)

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | 6,325 | 6,344 | 6,396 | 6,439 | 6,515 | 6,599 | 6,658 | 6,722 | 6,789 | 6,843 | 6,932 | 6,995 | 7,061 | 7,126 | 7,206 |
| **Commercial** | 4,063 | 4,077 | 4,112 | 4,141 | 4,174 | 4,202 | 4,231 | 4,251 | 4,270 | 4,293 | 4,327 | 4,356 | 4,385 | 4,418 | 4,450 |
| **Industrial** | 6,958 | 6,994 | 7,038 | 7,073 | 7,113 | 7,162 | 7,206 | 7,235 | 7,250 | 7,266 | 7,289 | 7,308 | 7,330 | 7,349 | 7,356 |
| **Total C/I** | 11,021 | 11,071 | 11,150 | 11,214 | 11,287 | 11,364 | 11,437 | 11,486 | 11,520 | 11,559 | 11,616 | 11,664 | 11,715 | 11,767 | 11,806 |
| **Public Authority** | 1,510 | 1,501 | 1,506 | 1,515 | 1,523 | 1,531 | 1,537 | 1,539 | 1,541 | 1,545 | 1,552 | 1,558 | 1,564 | 1,570 | 1,574 |
| **Utility Use and Lighting** | 39 | 39 | 39 | 39 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| **Sales for Resale** | 1,969 | 1,994 | 2,019 | 2,041 | 2,063 | 2,083 | 2,103 | 2,120 | 2,137 | 2,155 | 2,174 | 2,193 | 2,213 | 2,232 | 2,252 |
| **Total Kentucky** | 20,864 | 20,949 | 21,110 | 21,248 | 21,428 | 21,617 | 21,775 | 21,907 | 22,027 | 22,142 | 22,314 | 22,450 | 22,593 | 22,735 | 22,878 |
| **Virginia** | 909 | 911 | 905 | 910 | 914 | 921 | 924 | 927 | 932 | 935 | 944 | 948 | 953 | 957 | 960 |
| **Total KU Calendar Sales** | 21,773 | 21,860 | 22,015 | 22,158 | 22,342 | 22,538 | 22,699 | 22,834 | 22,959 | 23,077 | 23,258 | 23,398 | 23,546 | 23,692 | 23,838 |
| **Utility Use and Losses** | 1,349 | 1,353 | 1,362 | 1,372 | 1,381 | 1,396 | 1,406 | 1,410 | 1,419 | 1,428 | 1,443 | 1,451 | 1,456 | 1,462 | 1,474 |
| **Total Requirements** | 23,122 | 23,213 | 23,377 | 23,530 | 23,723 | 23,934 | 24,105 | 24,244 | 24,378 | 24,505 | 24,701 | 24,849 | 25,002 | 25,154 | 25,312 |

*KU residential and commercial customers in Kentucky are eligible to participate in DSM programs.

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

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Summer** | 4,399 | 4,437 | 4,483 | 4,521 | 4,563 | 4,608 | 4,640 | 4,680 | 4,704 | 4,731 | 4,772 | 4,812 | 4,844 | 4,869 | 4,887 |
| | **13/14** | **14/15** | **15/16** | **16/17** | **17/18** | **18/19** | **19/20** | **20/21** | **21/22** | **22/23** | **23/24** | **24/25** | **25/26** | **26/27** | **27/28** |
| **Winter** | 4,324 | 4,363 | 4,424 | 4,449 | 4,479 | 4,506 | 4,536 | 4,596 | 4,608 | 4,628 | 4,646 | 4,671 | 4,712 | 4,761 | 4,778 |

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

| | Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | **2014** | 697 | 627 | 571 | 433 | 370 | 503 | 601 | 607 | 482 | 377 | 445 | 612 | 6,325 |
| | **2015** | 697 | 628 | 572 | 439 | 370 | 504 | 602 | 608 | 483 | 380 | 447 | 614 | 6,344 |
| **Commercial** | **2014** | 350 | 303 | 302 | 282 | 312 | 369 | 401 | 403 | 347 | 328 | 318 | 350 | 4,065 |
| | **2015** | 350 | 304 | 303 | 281 | 313 | 370 | 403 | 404 | 348 | 330 | 320 | 352 | 4,078 |
| **Industrial** | **2014** | 575 | 509 | 528 | 511 | 599 | 613 | 630 | 650 | 565 | 590 | 577 | 609 | 6,956 |
| | **2015** | 581 | 513 | 533 | 512 | 603 | 617 | 633 | 653 | 568 | 591 | 578 | 611 | 6,993 |
| | | -------- | -------- | -------- | -------- | -------- | -------- | -------- | -------- | -------- | -------- | -------- | -------- | -------- |
| **Total C/I** | **2014** | 925 | 812 | 830 | 793 | 911 | 982 | 1,031 | 1,053 | 912 | 918 | 895 | 959 | 11,021 |
| | **2015** | 931 | 817 | 836 | 793 | 916 | 987 | 1,036 | 1,057 | 916 | 921 | 898 | 963 | 11,071 |
| **Public Authority** | **2014** | 128 | 111 | 113 | 109 | 123 | 134 | 141 | 143 | 127 | 126 | 123 | 131 | 1,509 |
| | **2015** | 127 | 111 | 113 | 108 | 122 | 133 | 141 | 142 | 126 | 125 | 122 | 131 | 1,501 |
| **Utility Use and Other** | **2014** | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 4 | 4 | 39 |
| | **2015** | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 4 | 4 | 39 |
| **Sales for Resale** | **2014** | 170 | 160 | 158 | 146 | 151 | 172 | 186 | 192 | 171 | 153 | 149 | 162 | 1,970 |
| | **2015** | 172 | 162 | 160 | 147 | 153 | 174 | 188 | 194 | 174 | 155 | 151 | 164 | 1,994 |
| | | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== |
| **Total Kentucky** | **2014** | 1,924 | 1,713 | 1,675 | 1,484 | 1,558 | 1,794 | 1,962 | 1,998 | 1,695 | 1,577 | 1,616 | 1,868 | 20,864 |
| | **2015** | 1,931 | 1,721 | 1,684 | 1,490 | 1,564 | 1,801 | 1,970 | 2,004 | 1,702 | 1,584 | 1,622 | 1,876 | 20,949 |
| **Virginia** | **2014** | 104 | 89 | 85 | 70 | 66 | 63 | 70 | 69 | 58 | 63 | 75 | 96 | 908 |
| | **2015** | 104 | 89 | 84 | 70 | 66 | 63 | 70 | 69 | 58 | 64 | 76 | 96 | 909 |
| **Total KU Calendar** | **2014** | 2,028 | 1,802 | 1,760 | 1,554 | 1,624 | 1,857 | 2,032 | 2,067 | 1,753 | 1,640 | 1,691 | 1,964 | 21,772 |
| | **2015** | 2,035 | 1,810 | 1,768 | 1,560 | 1,630 | 1,864 | 2,040 | 2,073 | 1,760 | 1,648 | 1,698 | 1,972 | 21,858 |
| **Requirements** | **2014** | 2,172 | 1,938 | 1,868 | 1,636 | 1,701 | 1,959 | 2,180 | 2,216 | 1,845 | 1,732 | 1,787 | 2,087 | 23,122 |
| | **2015** | 2,180 | 1,947 | 1,876 | 1,643 | 1,707 | 1,967 | 2,188 | 2,224 | 1,853 | 1,738 | 1,794 | 2,095 | 23,213 |

*KU residential and commercial customers in Kentucky are eligible to participate in DSM programs.

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

The impacts of existing and future demand-side programs on both energy sales and peak demands are estimated in Table 8.(3)(e)-3. The energy sales forecasts presented in the preceding sections 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.(3)(e)(3)-1, 8.(3)(e)(3)-2, 8.(4)(a)-1, 8.(4)(a)-2, and 6.(1)-23 for 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; Table 5.(3)-5 contains the energy and demand forecasts on an annual basis through 2028.

### 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

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

The national outlook for U.S Gross Domestic Product ("GDP"), industrial production and consumer prices are key macro-level variables that establish the broad market environment within which KU and LG&E operate. 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 as an input 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.

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

For the 2014 IRP, the KU and LG&E forecast of commercial sales is also the product of a sales-per-customer forecast and a forecast of the number of customers. Key inputs to the sales-per-customer forecast include real gross state product, retail employment, size of commercial establishment (square footage), efficiencies and saturation of HVAC and other equipment, and electricity prices. Information on real gross state product is provided by IHS Global Insight and appliance efficiencies and saturations are based on information from the Energy Information Administration.

Weather records are also a vital input to electricity sales forecasting. KU and LG&E receives their weather data from the National Climatic Data Center, a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. For the forecast period (2014-2028), averages of cooling and heating degree days based on the 20-year period ending in 2012 were used in the models. Lexington, Ky., Bristol, Tenn., and Bowman Field Louisville weather station data are used in the KU, ODP, and LG&E models, respectively. Degree-days used in the models are all on a 65-degree Fahrenheit base.

KU and LG&E also rely on company-collected survey data as inputs to the forecasting process. Such data enables KU and LG&E to estimate the mix of residential housing types within the service territories and the approximate saturation level of various appliances.

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

### *Key Economic and Demographic Assumptions*

Reliable forecasts of energy consumption consider the socio-economic conditions surrounding the forecast period. KU and LG&E subscribe to IHS Global Insight, a service that provides estimations of current economic conditions and forecasts of future conditions. Global Insight's 2013 Long-Term Macro Forecast and the Population and Household Forecast are both used in the 2014 IRP. See Section 5 and Section 6 for a description of the major content of the Global Insight reports and how the economic outlook has changed since the 2011 IRP. Copies of the economic and demographic forecasts are attached as part of Technical Appendix, 'Supporting Documents,' in Volume II.

## 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. The models are developed based on actual historical data and therefore capture the impact of DSM programs during those historical periods. Multiple Regression forecasting 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 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 customers..

Forecasts are based on 10 years of monthly sales history when available. For some newer rates, a shorter period is used. The modeling of residential and general service ("GS") sales also incorporate elements of end-use forecasting – covering base load, heating and cooling components of sales – which recognize expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

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

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

KU and LG&E update their load forecasts on an annual basis to capture 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)-1, 8.(3)(e)(3)-2, 8.(4)(a)-1, 8.(4)(a)-2, and 6.(1)-23 for KU and LG&E combined.

***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 2013 was 87 percent Kentucky-retail, 4 percent Virginia-retail, and 9 percent wholesale (FERC jurisdiction).

KU's sales forecast is comprised of 28 forecast models. Each model forecasts the number of customers, use-per-customer, or total sales on a monthly basis and is associated with one or more homogenous rate classes. Sales forecasts are initially produced on a billed basis for each rate, consistent with the collection of data for each rate class. Rate classes are then aggregated to yield the revenue class data (residential, commercial, industrial, etc.). 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 after DSM by Forecast Group* (GWh)**

| | Residential | Commercial | Industrial | Public Authority | Municipals | Lighting | Virginia Retail | KU Total |
|---|---|---|---|---|---|---|---|---|
| 2014 | 6,325 | 4,063 | 6,958 | 1,510 | 1,969 | 39 | 909 | 21,773 |
| 2015 | 6,344 | 4,077 | 6,994 | 1,501 | 1,994 | 39 | 911 | 21,860 |
| 2016 | 6,396 | 4,112 | 7,038 | 1,506 | 2,019 | 39 | 905 | 22,015 |
| 2017 | 6,439 | 4,141 | 7,073 | 1,515 | 2,041 | 39 | 910 | 22,158 |
| 2018 | 6,515 | 4,174 | 7,113 | 1,523 | 2,063 | 40 | 914 | 22,342 |
| 2019 | 6,599 | 4,202 | 7,162 | 1,531 | 2,083 | 40 | 921 | 22,538 |
| 2020 | 6,658 | 4,231 | 7,206 | 1,537 | 2,103 | 40 | 924 | 22,699 |
| 2021 | 6,722 | 4,251 | 7,235 | 1,539 | 2,120 | 40 | 927 | 22,834 |
| 2022 | 6,789 | 4,270 | 7,250 | 1,541 | 2,137 | 40 | 932 | 22,959 |
| 2023 | 6,843 | 4,293 | 7,266 | 1,545 | 2,155 | 40 | 935 | 23,077 |
| 2024 | 6,932 | 4,327 | 7,289 | 1,552 | 2,174 | 40 | 944 | 23,258 |
| 2025 | 6,995 | 4,356 | 7,308 | 1,558 | 2,193 | 40 | 948 | 23,398 |
| 2026 | 7,061 | 4,385 | 7,330 | 1,564 | 2,213 | 40 | 953 | 23,546 |
| 2027 | 7,126 | 4,418 | 7,349 | 1,570 | 2,232 | 40 | 957 | 23,692 |
| 2028 | 7,206 | 4,450 | 7,356 | 1,574 | 2,252 | 40 | 960 | 23,838 |

*KU residential and commercial customers in Kentucky are eligible to participate in DSM programs.

### *KU Residential Forecast*

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

#### *KU Residential Customer Forecasts*

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

#### *KU Residential Use-per-Customer Forecast*

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

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

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

***KU Commercial Forecast Group***

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

***KU General Service***

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

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

***KU PS-Secondary***

The KU PS-Secondary forecast includes all customers on the PS-Secondary rate. Sales to the PS-Secondary rate were modeled as a function of customer change, temperature, employment, and binary variables, which account for oddities in the data.

***KU TOD-Secondary***

The KU TOD-Secondary forecast includes all customers on the TOD-Secondary rate. Sales to the TOD-Secondary rate were modeled as a function of customer change, weather, the Industrial Production Index, and binary variables, which account for oddities in the data.

***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 customer change and weather.

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

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

#### *PS Primary*

The PS Primary forecast includes all customers on the PS rate schedule that take service at the primary distribution voltage. Sales to PS Primary customers were modeled as a function of customer change, weather, the Industrial Production Index, real price, and binary variables, which account for oddities in the data.

*TOD Primary*

The TOD Primary forecast includes all customers on the TOD rate schedule that take service at the primary distribution voltage. Sales to TOD Primary customers were modeled as a function of customer change, weather, the Industrial Production Index, and binary variables, which account for oddities in the data.

*Retail Transmission Service ("RTS")*

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

*Fluctuating Load Service*

The FLS forecast includes one customer on this rate: The North American Stainless Arc Furnace, which is developed based on discussions with that customer.

*LTOD Primary*

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

*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.

The municipal customers provide an annual forecast that is used in the development of the KU municipal forecast. Each of the three forecast models is discussed in more detail in the following sections.

***Transmission Municipal***

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

***Primary Municipal***

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

***City of Paris***

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

***KU Lighting Forecast Group***

The KU lighting forecast group consists of two forecast models: KU street lighting and KU private outdoor lighting. Each forecast was produced the same way, as the product of the monthly number of lighting hours, the monthly energy use-per-fixture-per-hour, and a monthly forecasted number of fixtures. For each of these forecasts, the monthly energy use-per-fixture-per-hour was held flat at 2013 levels, and the number of fixtures was forecasted by trending.

***ODP Sales Forecasts***

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

***ODP Residential Forecast***

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

***ODP Residential Customer Forecasts***

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

### *ODP Residential Use-per-Customer Forecast*

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

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

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

## *ODP Commercial Forecast Group*

The ODP commercial forecast group consists of four commercial forecast models: ODP GS, ODP Power Service ("PS") Secondary, ODP Time of Day (TOD) Secondary and ODP all-electric schools ("AES").

### *ODP General Service*

The ODP general service forecast includes all customers on the ODP GS rate and is comprised of two separate forecasts: a total use forecast and a customer forecast. Total use is forecasted using the SAE model. A discussion of the components and the methodology used to develop them is contained in Technical Appendix, *Commercial Forecast Model*, in Volume II.

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

***ODP PS-Secondary***

The ODP PS-Secondary forecast includes all customers on the PS-Secondary rate. Sales to the PS-Secondary rate were modeled as a function of customer change, temperature, employment, and binary variables, which account for oddities in the data.

***ODP TOD-Secondary***

The ODP TOD-Secondary forecast includes all customers on the TOD-Secondary rate. Sales to the TOD-Secondary rate were modeled as a function of customer change, weather, the Industrial Production Index, and binary variables, which account for oddities in the data.

***ODP All-Electric Schools***

The ODP all-electric schools forecast includes all customers on the all-electric school rate schedule. ODP AES sales were modeled as a function of the number of customer growth, and weather.

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

### *PS Primary*

The PS Primary forecast includes all customers on the PS rate schedule that take service at the primary distribution voltage. Sales to PS Primary customers were modeled as a function of customer change, weather, the Industrial Production Index, real price, and binary variables, which account for oddities in the data.

### *TOD Primary*

The TOD Primary forecast includes all customers on the TOD rate schedule that take service at the primary distribution voltage. Sales to TOD Primary customers were modeled as a function of customer change, weather, the Industrial Production Index, and binary variables, which account for oddities in the data.

### *Retail Transmission Service ("RTS")*

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

## *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 addressed by reviewing and revising the 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 2014 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 2018, energy requirements and peak demand are approximately 6 percent higher (roughly 1,494 GWh and 281 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 6 percent lower in 2018 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.

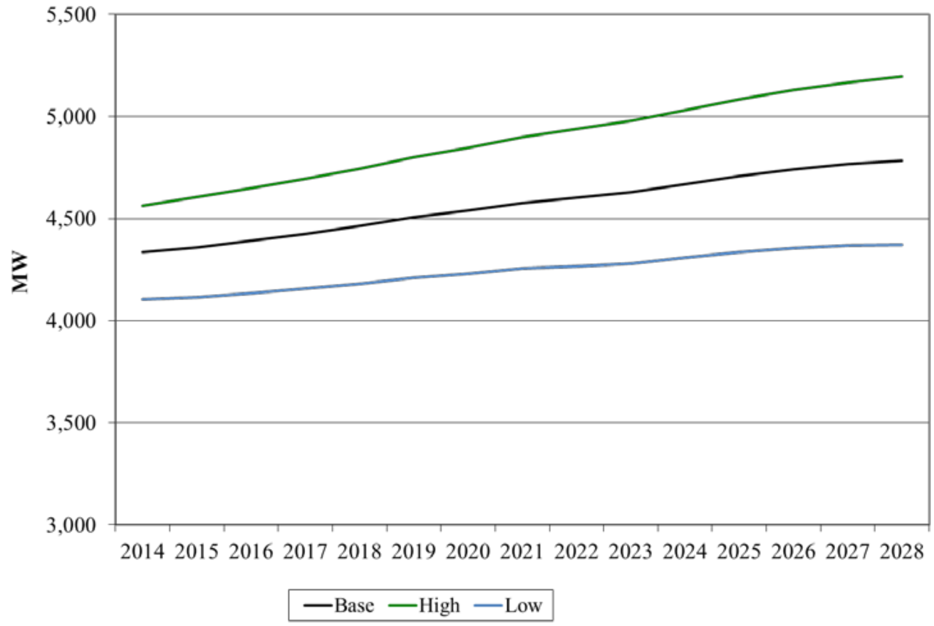
**Table 7.(7)(e)-1**
**KU Base, High, and Low Energy Requirements Forecasts after DSM (GWh)**

| YEAR | Base | High | Low |
|---|---|---|---|
| 2014 | 23,122 | 24,342 | 21,903 |
| 2015 | 23,213 | 24,515 | 21,911 |
| 2016 | 23,377 | 24,742 | 22,012 |
| 2017 | 23,530 | 24,961 | 22,099 |
| 2018 | 23,723 | 25,217 | 22,230 |
| 2019 | 23,934 | 25,496 | 22,372 |
| 2020 | 24,105 | 25,741 | 22,469 |
| 2021 | 24,244 | 25,953 | 22,534 |
| 2022 | 24,378 | 26,158 | 22,598 |
| 2023 | 24,505 | 26,351 | 22,659 |
| 2024 | 24,701 | 26,609 | 22,793 |
| 2025 | 24,849 | 26,824 | 22,874 |
| 2026 | 25,002 | 27,044 | 22,961 |
| 2027 | 25,154 | 27,261 | 23,047 |
| 2028 | 25,312 | 27,486 | 23,138 |

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

| YEAR | Base | High | Low |
|---|---|---|---|
| 2014 | 4,334 | 4,562 | 4,105 |
| 2015 | 4,360 | 4,604 | 4,115 |
| 2016 | 4,391 | 4,648 | 4,135 |
| 2017 | 4,425 | 4,694 | 4,156 |
| 2018 | 4,462 | 4,743 | 4,181 |
| 2019 | 4,505 | 4,800 | 4,211 |
| 2020 | 4,538 | 4,846 | 4,230 |
| 2021 | 4,577 | 4,900 | 4,255 |
| 2022 | 4,602 | 4,938 | 4,266 |
| 2023 | 4,628 | 4,977 | 4,279 |
| 2024 | 4,670 | 5,030 | 4,309 |
| 2025 | 4,709 | 5,084 | 4,335 |
| 2026 | 4,742 | 5,129 | 4,354 |
| 2027 | 4,767 | 5,166 | 4,367 |
| 2028 | 4,784 | 5,195 | 4,373 |

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




### 7.(7)(f) Research and Development

The 2014 IRP includes three minor changes to its forecasting process. In the 2011 IRP, the company used class-specific load profiles to develop its hourly demand forecasts. This approach enabled the Company to better reflect demand-side management programs that impact the load profile of specific classes. In the 2014 IRP, the company further improved this process by using historical hourly shapes by company, month, and day of week with different weather ranges to better reflect load shapes for different temperature ranges.

In the 2011 IRP, home appliance saturation surveys of both LG&E and KU customers provided responses that were used to develop assumptions for the residential forecasting models. In the 2014 IRP, the home appliance saturation surveys continued to be used in the residential forecasting models. In addition, commercial end-use surveys were conducted and used to develop assumptions for small commercial forecasting models.

Kentucky Real Gross State Product was used as the primary economic driver of the small commercial sales forecast in the 2011 IRP. In the 2014 IRP, the Companies also used Kentucky retail employment as a key driver in the small commercial forecast.

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

In February 2011, KU and LG&E conducted a small commercial end-use survey. The Companies also participate in an Energy Forecaster Group managed by Itron, in which collaborative efforts with other utilities provide the development of regional end-use saturation and efficiency data for the various classes of service.

**Louisville Gas and Electric Company**

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

The data submissions in the following subsections conform to the specifications provided in Section 7.(1) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible. Energy and demand forecasts reflect the impact of the Companies' Demand Side Management (DSM) programs.

**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. Energy and demand forecasts reflect the impact of the Companies' Demand Side Management (DSM) programs.

**7.(2)(a) LG&E Average Customers by Class, 2009-2013**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Residential** | 344,677 | 349,049 | 347,833 | 346,445 | 348,048 |
| **Commercial** | 41,354 | 42,292 | 41,529 | 41,858 | 42,062 |
| **Industrial** | 411 | 433 | 409 | 411 | 429 |
| **Street Lighting** | 841 | 69 | 335 | 631 | 650 |
| **Public Authority** | 3,542 | 4,025 | 3,957 | 4,093 | 4,124 |
| **Total Customers** | 390,825 | 395,868 | 394,063 | 393,438 | 395,313 |

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

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **SYSTEM BILLED SALES:** | | | | | |
| **Recorded** | 11,333 | 12,277 | 11,783 | 11,768 | 11,682 |
| **Weather Normalized** | 11,562 | 11,712 | 11,617 | 11,696 | 11,726 |
| **SYSTEM USED SALES:** | | | | | |
| **Recorded** | 11,405 | 12,338 | 11,641 | 11,837 | 11,698 |
| **Weather Normalized** | 11,596 | 11,772 | 11,444 | 11,775 | 11,732 |
| **ENERGY REQUIREMENTS:** | | | | | |
| **Recorded** | 11,958 | 12,906 | 12,364 | 12,352 | 12,245 |
| **Weather Normalized** | 12,149 | 12,340 | 12,167 | 12,290 | 12,279 |
| **RECORDED SALES BY CLASS:** | | | | | |
| **Residential** | 4,096 | 4,592 | 4,260 | 4,259 | 4,164 |
| **Commercial** | 3,617 | 3,793 | 3,709 | 3,734 | 3,685 |
| **Large Power** | 2,412 | 2,603 | 2,430 | 2,666 | 2,700 |
| **Public Authorities** | 1,221 | 1,296 | 1,191 | 1,157 | 1,131 |
| **Lighting** | 59 | 54 | 51 | 21 | 18 |
| | --------- | --------- | --------- | --------- | --------- |
| **TOTAL LG&E SALES** | 11,405 | 12,338 | 11,641 | 11,837 | 11,698 |
| **SYSTEM LOSSES** | 524 | 542 | 708 | 499 | 525 |
| **Utility Use** | 29 | 26 | 15 | 16 | 22 |
| **ENERGY** | 11,958 | 12,906 | 12,364 | 12,352 | 12,245 |

| REQUIREMENTS | | | | | |
|---|---|---|---|---|---|
| **WEATHER NORMALIZED SALES BY CLASS:** | | | | | |
| **Residential** | 4,224 | 4,186 | 4,122 | 4,224 | 4,190 |
| **Commercial** | 3,642 | 3,727 | 3,656 | 3,711 | 3,691 |
| **Large Power** | 2,420 | 2,595 | 2,426 | 2,662 | 2,701 |
| **Public Authorities** | 1,223 | 1,292 | 1,189 | 1,157 | 1,131 |
| **Lighting** | 59 | 54 | 51 | 21 | 18 |

**7.(2)(c) LG&E Coincident Peak Demands (MW)**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **SUMMER Actual** | 2,479 | 2,852 | 2,654 | 2,718 | 2,515 |
| | **2008/2009** | **2009/2010** | **2010/2011** | **2011/2012** | **2012/2013** |
| **WINTER Actual** | 1,915 | 1,845 | 1,823 | 1,690 | 1,754 |

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

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Energy Sales (GWh)** | 11,158 | 11,867 | 11,395 | 11,464 | 11,308 |
| **Coincident Peak Demand (MW)** | 2,447 | 2,799 | 2,625 | 2,658 | 2,486 |

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

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Energy Sales (GWh)** | 247 | 471 | 246 | 373 | 390 |
| **Coincident Peak Demand (MW)** | 32 | 53 | 28 | 60 | 28 |

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

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Annual Energy Loss** | 524 | 542 | 708 | 499 | 525 |
| **Loss Percent of Energy Requirements** | 4.4% | 4.2% | 5.7% | 4.0% | 4.3% |

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

See KU 7.(2)(g).

**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)**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Residential** | 11,884 | 13,156 | 12,247 | 12,293 | 11,964 |
| **Commercial** | 87,464 | 89,686 | 89,311 | 89,206 | 87,609 |
| **Industrial** | 5,868,613 | 6,011,547 | 5,941,320 | 6,486,618 | 6,293,706 |
| **Public Authority** | 344,720 | 321,988 | 300,986 | 282,678 | 274,248 |
| **Utility Use and Other** | 70,155 | 782,609 | 152,239 | 33,281 | 27,692 |

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**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Residential** | 36% | 37% | 37% | 36% | 36% |
| **Commercial** | 32% | 31% | 32% | 32% | 32% |
| **Industrial** | 21% | 21% | 21% | 22% | 22% |
| **Public Authority** | 11% | 11% | 10% | 10% | 10% |
| **Lighting** | 0% | 0% | 0% | 0% | 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 2009, the total number of residential customers has increased at an annual rate of 0.2 percent. Weather-normalized sales decreased at an annual rate of 0.2 percent.

*LG&E Commercial Energy Sales*

Weather-normalized sales to the commercial class grew at an average annual rate of 0.3 percent since 2009. This slow growth rate was primarily due to low use-per-customer growth. The number of customers increased from 41,354 customers in 2009 to 42,062 in 2013, a 0.4 percent annual growth rate.

*LG&E Industrial Energy Sales*

Energy sales to LG&E's industrial class increased at an annual growth rate of 2.9 percent over the 2009-2013 period. Manufacturing has largely recovered following the recession that ended in June 2009.

**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 after DSM* (GWh)

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | 4,234 | 4,252 | 4,291 | 4,349 | 4,418 | 4,492 | 4,551 | 4,613 | 4,675 | 4,732 | 4,811 | 4,873 | 4,938 | 5,008 | 5,092 |
| **Small Commercial** | 1,404 | 1,407 | 1,415 | 1,419 | 1,424 | 1,430 | 1,437 | 1,438 | 1,442 | 1,447 | 1,456 | 1,463 | 1,467 | 1,475 | 1,482 |
| **Large Commercial** | 2,290 | 2,288 | 2,285 | 2,282 | 2,281 | 2,281 | 2,281 | 2,281 | 2,281 | 2,281 | 2,282 | 2,281 | 2,281 | 2,282 | 2,281 |
| **Industrial** | 2,823 | 2,890 | 2,946 | 2,967 | 2,995 | 3,012 | 3,029 | 3,043 | 3,059 | 3,081 | 3,105 | 3,126 | 3,146 | 3,171 | 3,197 |
| **Public Authority** | 1,136 | 1,129 | 1,122 | 1,113 | 1,115 | 1,117 | 1,118 | 1,119 | 1,119 | 1,121 | 1,123 | 1,124 | 1,125 | 1,127 | 1,129 |
| **Utility Use and Lighting** | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| | ==== | ==== | ==== | ==== | ==== | ==== | ==== | ==== | ==== | ==== | ==== | ==== | ==== | ==== | ==== |
| **Total LG&E Calendar** | 11,906 | 11,985 | 12,078 | 12,149 | 12,252 | 12,351 | 12,435 | 12,513 | 12,595 | 12,681 | 12,796 | 12,886 | 12,976 | 13,082 | 13,200 |
| **Utility Use and Losses** | 688 | 694 | 698 | 704 | 709 | 713 | 720 | 723 | 731 | 736 | 738 | 743 | 753 | 754 | 767 |
| **Requirements** | 12,594 | 12,679 | 12,776 | 12,853 | 12,961 | 13,064 | 13,155 | 13,236 | 13,326 | 13,417 | 13,534 | 13,629 | 13,729 | 13,836 | 13,967 |

*LG&E residential and commercial customers are eligible to participate in DSM programs.

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

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Summer** | 2,738 | 2,766 | 2,785 | 2,813 | 2,837 | 2,854 | 2,881 | 2,899 | 2,934 | 2,962 | 2,976 | 2,991 | 3,014 | 3,045 | 3,084 |
| | **13/14** | **14/15** | **15/16** | **16/17** | **17/18** | **18/19** | **19/20** | **20/21** | **21/22** | **22/23** | **23/24** | **24/25** | **25/26** | **26/27** | **27/28** |
| **Winter** | 1,794 | 1,819 | 1,849 | 1,865 | 1,884 | 1,888 | 1,900 | 1,922 | 1,930 | 1,941 | 1,952 | 1,965 | 1,983 | 2,005 | 2,017 |

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

| | Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | **2014** | 360 | 324 | 306 | 255 | 278 | 409 | 512 | 499 | 399 | 281 | 266 | 345 | 4,234 |
| | **2015** | 361 | 326 | 307 | 259 | 279 | 410 | 515 | 502 | 400 | 283 | 266 | 345 | 4,253 |
| **Small Commercial** | **2014** | 117 | 103 | 108 | 103 | 115 | 126 | 146 | 147 | 116 | 107 | 106 | 110 | 1,404 |
| | **2015** | 118 | 103 | 109 | 102 | 116 | 126 | 146 | 147 | 117 | 107 | 106 | 111 | 1,408 |
| **Large Commercial** | **2014** | 181 | 167 | 175 | 171 | 200 | 220 | 232 | 231 | 191 | 179 | 170 | 174 | 2,291 |
| | **2015** | 182 | 167 | 175 | 170 | 200 | 220 | 232 | 231 | 191 | 178 | 169 | 174 | 2,289 |
| **Industrial** | **2014** | 222 | 193 | 216 | 224 | 259 | 266 | 263 | 273 | 213 | 228 | 230 | 235 | 2,822 |
| | **2015** | 226 | 197 | 220 | 228 | 265 | 272 | 270 | 280 | 219 | 233 | 237 | 242 | 2,889 |
| **Public Authority** | **2014** | 94 | 81 | 88 | 85 | 101 | 106 | 115 | 113 | 89 | 88 | 87 | 90 | 1,137 |
| | **2015** | 94 | 81 | 87 | 84 | 100 | 105 | 114 | 112 | 89 | 87 | 86 | 90 | 1,129 |
| **Utility Use and Other** | **2014** | 2 | 2 | 2 | 1 | 2 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 19 |
| | **2015** | 2 | 2 | 2 | 1 | 2 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 19 |
| | | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== | ====== |
| **Total LG&E Calendar** | **2014** | 976 | 870 | 895 | 839 | 955 | 1,128 | 1,269 | 1,264 | 1,009 | 885 | 861 | 956 | 11,907 |
| | **2015** | 983 | 876 | 900 | 844 | 962 | 1,134 | 1,278 | 1,273 | 1,017 | 890 | 866 | 964 | 11,987 |
| **Requirements** | **2014** | 1,032 | 921 | 943 | 881 | 1,001 | 1,195 | 1,362 | 1,353 | 1,062 | 927 | 906 | 1,010 | 12,594 |
| | **2015** | 1,039 | 927 | 949 | 890 | 1,007 | 1,203 | 1,371 | 1,362 | 1,070 | 933 | 912 | 1,017 | 12,679 |

*LG&E residential and commercial customers are eligible to participate in DSM programs.

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

The impacts of existing and future demand-side programs on both energy sales and peak demands are estimated in Table 8.(3)(e)-3. The energy sales forecasts presented in the preceding sections 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.(3)(e)(3)-1, 8.(3)(e)(3)-2, 8.(4)(a)-1, 8.(4)(a)-2, and 6.(1)-23 for 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***

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

### 7.(7)(c) General Methodological Approach

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

LGE's sales forecast is comprised of 13 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 after DSM by Forecast Group* (GWh)**

| | Residential | Sm Comm | Lg Comm | Industrial | Public Authority | Lighting | LG&E Total |
|---|---|---|---|---|---|---|---|
| 2014 | 4,234 | 1,404 | 2,290 | 2,823 | 1,136 | 19 | 11,906 |
| 2015 | 4,252 | 1,407 | 2,288 | 2,890 | 1,129 | 19 | 11,985 |
| 2016 | 4,291 | 1,415 | 2,285 | 2,946 | 1,122 | 19 | 12,078 |
| 2017 | 4,349 | 1,419 | 2,282 | 2,967 | 1,113 | 19 | 12,149 |
| 2018 | 4,418 | 1,424 | 2,281 | 2,995 | 1,115 | 19 | 12,252 |
| 2019 | 4,492 | 1,430 | 2,281 | 3,012 | 1,117 | 19 | 12,351 |
| 2020 | 4,551 | 1,437 | 2,281 | 3,029 | 1,118 | 19 | 12,435 |
| 2021 | 4,613 | 1,438 | 2,281 | 3,043 | 1,119 | 19 | 12,513 |
| 2022 | 4,675 | 1,442 | 2,281 | 3,059 | 1,119 | 19 | 12,595 |
| 2023 | 4,732 | 1,447 | 2,281 | 3,081 | 1,121 | 19 | 12,681 |
| 2024 | 4,811 | 1,456 | 2,282 | 3,105 | 1,123 | 19 | 12,796 |
| 2025 | 4,873 | 1,463 | 2,281 | 3,126 | 1,124 | 19 | 12,886 |
| 2026 | 4,938 | 1,467 | 2,281 | 3,146 | 1,125 | 19 | 12,976 |
| 2027 | 5,008 | 1,475 | 2,282 | 3,171 | 1,127 | 19 | 13,082 |
| 2028 | 5,092 | 1,482 | 2,281 | 3,197 | 1,129 | 19 | 13,200 |

*LG&E residential and commercial customers are eligible to participate in DSM programs.

***LG&E Residential Forecast***

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

***LG&E Residential Customers***

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

***LG&E Residential Use-per-Customer Forecast***

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

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

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

***LG&E Commercial Forecast Group***

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

***LG&E Small Commercial Forecast***

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

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

***LG&E Large Commercial Forecast***

The LG&E Large Commercial forecast includes all customers on the Commercial Power Service ("CPS") and Commercial Time-of-Day ("CTOD") rate schedules.

### *Large Commercial Primary*

LG&E Large Commercial primary sales were forecasted in total as a function of weather, customers, and employment. CPS Primary and CTOD Primary are modeled together and then allocated to each rate based on customer forecasts and history. Modeling these rates together compensates for the effects of rate-switching within the historical data set to achieve a more accurate forecast.

### *Large Commercial Secondary*

LG&E Large Commercial Secondary sales were forecasted in total as a function of weather, customers, and employment. CPS Secondary and CTOD Secondary are modeled together and then allocated to each rate based on customer forecasts and history. Modeling these rates together compensates for the effects of rate-switching within the historical data set to achieve a more accurate forecast.

## *LG&E Industrial Forecast Group*

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

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

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

***Industrial Primary***

LG&E Large Commercial primary sales were forecasted in total as a function of weather, customers and industrial production. IPS Primary and ITOD Primary are modeled together and then allocated to each rate based on customer forecasts and history. Modeling these rates together compensates for the effects of rate-switching within the historical data set to achieve a more accurate forecast.

***Industrial Secondary***

LG&E Large Commercial primary sales were forecasted in total as a function of weather, customers, employment and industrial production. IPS Secondary and ITOD Secondary are modeled together and then allocated to each rate based on customer forecasts and history. Modeling these rates together compensates for the effects of rate-switching within the historical data set to achieve a more accurate forecast.

*Special Contract*

Ft. Knox and the Louisville Water Company are individually forecasted major accounts with separate rates. These forecasts are developed after reviewing account information from the Major Account representatives for each firm.

***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 2013 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.

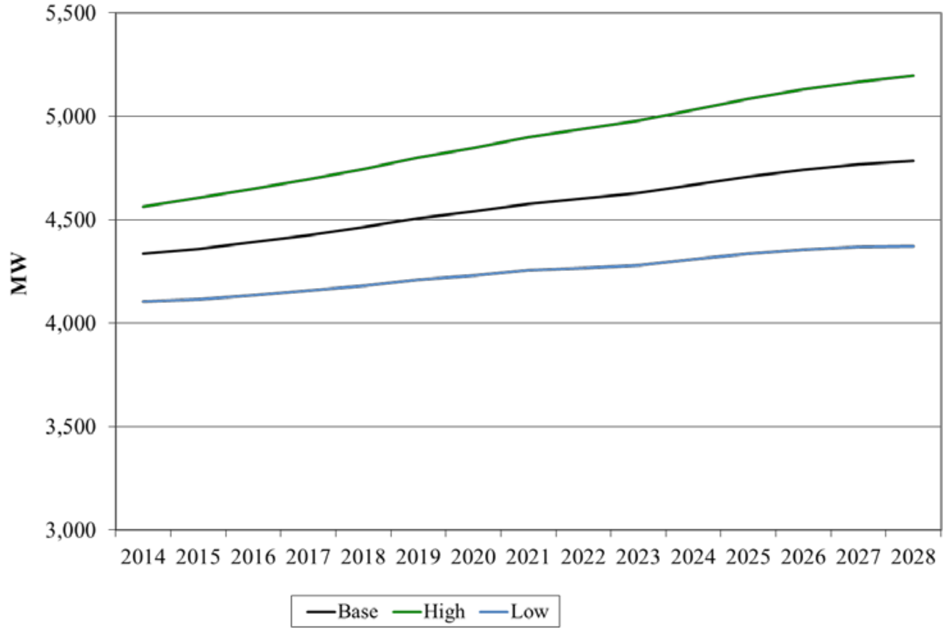
**Table 7.(7)(e)-1**
**LG&E Base, High, and Low Energy Requirements Forecasts after DSM (GWh)**

| YEAR | Base | High | Low |
|---|---|---|---|
| 2014 | 12,594 | 13,038 | 12,151 |
| 2015 | 12,679 | 13,105 | 12,252 |
| 2016 | 12,776 | 13,193 | 12,359 |
| 2017 | 12,853 | 13,271 | 12,436 |
| 2018 | 12,961 | 13,386 | 12,536 |
| 2019 | 13,064 | 13,509 | 12,620 |
| 2020 | 13,155 | 13,629 | 12,682 |
| 2021 | 13,236 | 13,743 | 12,729 |
| 2022 | 13,326 | 13,868 | 12,783 |
| 2023 | 13,417 | 13,999 | 12,836 |
| 2024 | 13,534 | 14,157 | 12,912 |
| 2025 | 13,629 | 14,298 | 12,960 |
| 2026 | 13,729 | 14,447 | 13,011 |
| 2027 | 13,836 | 14,603 | 13,069 |
| 2028 | 13,967 | 14,786 | 13,147 |

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

| YEAR | Base | High | Low |
|---|---|---|---|
| 2014 | 2,655 | 2,749 | 2,562 |
| 2015 | 2,679 | 2,769 | 2,589 |
| 2016 | 2,693 | 2,781 | 2,606 |
| 2017 | 2,720 | 2,808 | 2,631 |
| 2018 | 2,737 | 2,827 | 2,647 |
| 2019 | 2,752 | 2,845 | 2,658 |
| 2020 | 2,779 | 2,879 | 2,679 |
| 2021 | 2,798 | 2,905 | 2,691 |
| 2022 | 2,832 | 2,947 | 2,716 |
| 2023 | 2,860 | 2,984 | 2,736 |
| 2024 | 2,873 | 3,005 | 2,741 |
| 2025 | 2,888 | 3,030 | 2,747 |
| 2026 | 2,912 | 3,064 | 2,759 |
| 2027 | 2,943 | 3,106 | 2,780 |
| 2028 | 2,982 | 3,157 | 2,807 |

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




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

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

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

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

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## 8. RESOURCE ASSESSMENT

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

The mandate for the Companies' Integrated Resource Plan ("IRP") is to meet future energy requirements within their service territories at the lowest reasonable cost consistent with reliable supply. In 2011, the Companies announced plans to retire approximately 800 MW of coal-fired capacity to comply with the U.S. EPA's National Ambient Air Quality Standards and Mercury and Air Toxics Standards. In February 2013, the Companies retired Tyrone 3; the IRP assumes the three Cane Run and two Green River coal units will be retired in 2015. To offset this loss of energy and capacity, the Companies proposed to construct a 640 MW 2x1 Natural Gas Combined Cycle ("NGCC") unit at their Cane Run site to be online in 2015 ("Cane Run 7" or "CR7") and purchase the existing LS Power Bluegrass facility in LaGrange, Kentucky (495 MW of simple-cycle combustion turbines ("SCCTs")).

The construction of Cane Run 7 is underway and on schedule. However, the Companies were unable to purchase the Bluegrass facility after receiving an unfavorable Federal Energy Regulatory Commission ("FERC") ruling in May 2012. After preparing a new load forecast in the summer of 2012, it was confirmed that without the Bluegrass facility, additional resources would be required as early as 2015 in order to reliably serve customers' capacity and energy needs.

To meet the long-term need for capacity and energy, the Companies issued an RFP in September 2012. Based on the analysis of RFP responses, self-build alternatives, and DSM programs, the Companies submitted an application for Certificates of Public Convenience and

Necessity ("CPCN") in January 2014 to the Kentucky Public Service Commission for the construction of (a) a solar photovoltaic ("PV") facility at the E.W. Brown station in 2016 and (b) a natural gas combined cycle ("NGCC") unit at the Green River station in 2018.[1] The CPCN does not address the Companies' need for capacity and energy in 2015 through 2017. The Companies plan to address this need by exploring all available options, including (but not limited to) alternatives from parties that provided responses to the September 2012 RFP and extending the life of Green River units 3 and 4.[2] Cane Run 7, the short-term capacity additions in 2015 through 2017, and the proposed solar PV and NGCC facilities complete the Companies' expansion plan through 2018. The purpose of this study is to update the Companies' forecasted expansion plan beyond 2018.

The Companies continually evaluate their resource needs. This study represents a snapshot of this ongoing resource planning process using current business assumptions and assessment of risks. Because the planning process is constantly evolving, the Companies' least-cost expansion plan may be revised as conditions change and as new information becomes available. Even though the IRP represents the Companies' analysis of the best options to meet customer needs at this given point in time, this plan is reviewed, re-evaluated, and assessed against other market available alternatives prior to commitment and implementation.

The Companies' integrated resource planning process consists of the following activities: 1) assessment of demand-side options, 2) forecasting system energy requirements and peak demands, 3) determination of a target reserve margin criterion, 4) adequacy assessment of

[1] See Case No. 2014-00002.

[2] Based on compliance requirements and date in the MATS regulations, Green River units 3 and 4 cannot be operated after April of 2015 without additional emission controls. The regulations do provide for extensions of 1 or 2 years from that date, if granted by the permitting authority. At this time, the Companies have not sought extension of the compliance date, but are analyzing this option.

existing generating units and purchase power agreements, and 5) assessment of supply-side options. The impact of the Companies' demand-side management programs are reflected in the forecast of energy requirements and peak demands. Then, the Companies' resource assessment combines key elements of the remaining activities into a plan for meeting future energy requirements at the lowest reasonable cost.

For the purpose of developing resource expansion plans, the Companies target a minimum 16 percent reserve margin. A complete discussion of the Companies' reserve margin analysis is included in Volume III, Technical Appendix (see report titled *2014 Reserve Margin Analysis*).

Existing capacity resources consist of company-owned generating units and firm purchase power agreements with Ohio Valley Electric Corporation ("OVEC"). The capacities and operating characteristics of these resources are discussed in more detail in the following sections.

As part of the DSM filing on January 17, 2014 (Case No. 2014-00003), the Companies proposed one new DSM program (Automated Meter Systems), and enhancements to several existing programs, the evaluations of which are discussed in Section 8.(3)(e) of this report. As mentioned previously, the impact of DSM programs is fully reflected in the Companies' load forecasts.

The Companies' resource assessment was completed in two parts. First, the Companies performed a screening analysis of more than 50 supply-side technology options to determine a subset of the most competitive options. Then, this subset of technology options was incorporated into a detailed expansion planning analysis to determine the optimal expansion plans beyond 2018.

While there are a number of uncertainties that could have some impact on the Companies' resource decisions, the uncertainties in native load (demand and energy), natural gas prices, and greenhouse gas ("GHG") regulations are the most important to consider when evaluating long-term generating resources. Therefore, the Companies developed optimal expansion plans for multiple gas price, load, and GHG scenarios. These plans are discussed in more detail in Section 8.(4). A complete summary of the Companies' analysis is contained in Volume III, Technical Appendix (see report titled *2014 Resource Assessment*).

## 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 are coordinated across the Companies' generation fleet such that the outages will have the least economic and reliability impact to the customers and the Companies. The Companies continuously evaluate potential improvements, economic and otherwise, through routine maintenance of their generation fleet.

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

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

***Efficiency Improvements***

The plan did not evaluate the potential for future generation efficiency improvements. However, the Companies continue to evaluate economic improvements to their existing generation fleet, with consideration of the environmental rules for such modifications. Since the 2011 IRP, these improvements include updating controls to the latest technologies, turbine overhauls and repair work, boiler tube replacements, pulverizer rebuilds, air quality control upgrades, cooling system improvements, and generator reliability improvements. Also included in this section are a number of other projects that have furthered efforts to reduce environmental impact and meet regulatory compliance.

***Controls/Distributed Control Systems/Generator***

Technologically advanced controls continue to be one of the most proven applications for improving the efficiency of generating stations. New control technologies allow for tighter control of key operating parameters and provide for optimization of integrated systems not previously available with analog controls. There have been several upgrades to distributed control systems (DCS) throughout the system, including hardware upgrades on Brown 3, Mill Creek 2, 3, and 4, Trimble County 1; and a new DCS historian server at Brown 2. Additionally, the Companies have improved the control on some turbines, including electrohydraulic controls (EHC) upgrades at Mill Creek 1 and 3, and Brown 1 and 2. Other turbine/generator electrical upgrades in the system include improved synchronization controls on Green River 3 and 4; generator rewind/refurbishments on Cane Run 4 and Brown 3; and replacement of the voltage regulators on Brown 3, and Ghent 1, 2, and 3.

***Turbines/Boiler Feed Pumps***

Another proven area to improve efficiency in generating stations is restoring turbine degradation. A worn/degraded turbine can decrease the station efficiency by not extracting as much energy from the steam as possible. Major turbine overhauls were completed on Mill Creek 1, 2, and 3; Ghent 2, and 3, and Brown 3. Repair work was completed on other turbines in the fleet as well. The overhauls included ensuring all stationary sealing joints are serviceable, refurbishing radial steam seals, replacing HP inlet seal rings, ensuring optimal steam flow by restoring area dimensions on rotating and stationary blading, and polishing defects from rotating and stationary blade replacement to restore turbine efficiency to, or near to, design values.

Boiler feed pump degradation also robs the steam/water cycle of efficiency. If pumps are not running within their design parameters, then they require extra power, in the form of either steam or electricity, to drive the required flow. In the case of turbine driven pumps, the feed pump turbine is also overhauled to restore its efficiency. Pumps are typically overhauled along with the main turbines. Boiler feed pumps were refurbished at the following locations: Mill Creek 1, 2, and 3; Ghent 2 and 3; Brown 3, and Green River 4. The overhauls also included the drive turbines for Ghent 2 and 3, Brown 3, and Mill Creek 3. Additionally, significant work was also completed on feed pumps (turbine/pump coupling and motor rewinds respectively) on Mill Creek 4 and Brown 2.

***Boiler Tubes/Burners/Precipitators/Combustion***

Boiler tube failures continue to be the largest contributor to the fleet's equivalent forced outage rate. As native load continues to increase, boiler demand also increases. Although equipment is aging, units are still required to run at peak capacity. To improve availability, boiler tube studies and inspections were conducted using software modeling tools and the latest technology to identify boiler sections in need of replacement. All units across the fleet have undergone scheduled boiler outages to replace varying boiler tube sections. Additionally, thermal sprays/coatings were installed on some of the tube surfaces on Mill Creek 1 and 3 to combat fire-side corrosion issues. These efforts continue to maintain boiler availability and reliability.

Changes in coal supply and coal burners to reduce gaseous emissions have negatively impacted boiler slagging and precipitator performance. The Companies installed new burners or modified existing burners on the following units to more efficiently burn the fuel while still minimizing emissions: Mill Creek 1 and 3, Trimble County 1, and Brown 2 and 3. Precipitator upgrades/rebuild projects were performed on the following units: Ghent 2 and 3, Brown 1, 2, and 3, and Trimble County 1. In addition, a coal test burn program was implemented along with advanced modeling using fuel performance software to improve boiler efficiency and reduce boiler slagging. Successful test burns were carried out on Mill Creek 1, Trimble County 1, and Brown 1, 2, and 3. Combustion monitoring also plays a part in mitigating slagging and ensuring proper boiler performance. Carbon monoxide and combustion monitoring equipment was installed on Mill Creek 3, and Ghent 1-4.

***Other Improvements***

The following efficiency and unit derate improvements were also completed at various plants in the fleet:

- Pulverizer rebuilds on all units.
- Cooling tower refurbishment at Mill Creek 2 (includes fan variable frequency drives), and Ghent 4.
- Cooling tower pump overhauls at Mill Creek 2, 3, and 4, and circulating water pump overhaul on Mill Creek 1.
- Cooling tower header replacement on Ghent 3.
- Air compressor replacements and controls upgrades on numerous units to improve operating efficiency and reduce the number of instrument-related unit derates
- Gas path outlet duct and expansion joint replacement on numerous units to improve boiler performance issues and reduce pluggage in the unit scrubber modules.
- Air heater basket replacements on numerous units to improve air flow and boiler efficiency.
- The following improvements to condensate equipment were completed:

  - Feedwater heaters were replaced on Ghent 2 and 3 as well as Brown 1 and 2 to maximize heat transfer to the water entering the boiler.
  - Mill Creek 2 underwent a partial condenser retube to maximize heat transfer in the condenser.
  - Condenser vacuum pumps were overhauled on Mill Creek 2, Brown 3, and Trimble County 2 to improve heat transfer.

***Air Quality Control Systems***

Several environmental capital projects were completed since the 2011 IRP. Many of these projects were completed on Selective Catalytic Reduction units (SCRs) in the system. The SCRs allow for the reduction of $NO_X$ emissions in the flue gas via ammonia injection. The SCR catalyst must be in proper operating condition to affect $NO_X$ removal and prevent ammonia slip, which allows ammonia downstream to form ammonium bisulfate on air heater baskets. The following SCR projects were completed:

- New SCR was installed on Brown 3.
- Third catalyst layer was installed on Trimble County 2, Ghent 3, and Ghent 4.
- New catalyst material was installed on existing layers at Ghent 1 and 4 as well as Trimble County 1.
- Regenerated catalyst material was installed on existing layers in Mill Creek 3 and 4, and Ghent 1.

Several other air quality/emissions projects were completed since the 2011 IRP involving other types of emissions control equipment. Flue Gas Desulfurization (“FGD”) equipment reduces the amount of $SO_2$ emissions in the flue gas. The following FGD projects were completed:

- Trimble County limestone mill upgrades.
- Ghent 3 and 4 FGD agitator blade replacement.
- Mill Creek 1 and 3 new FGD mist eliminators.
- Mill Creek 3 and 4 new FGD reactant feed piping.
- Mill Creek 2 FGD oxidation air compressor motor rewind.

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

***Fleet Wide Initiatives***

A fleet-wide effort to review and analyze manufacturer reporting, equipment monitoring, and engineering programs has resulted in the following projects and initiatives:

- A generator step-up maintenance and risk mitigation program to address both short and long term maintenance practices and strategic risk mitigation.
- Beginning in 2010, multiple sets of critical generator stator bars were purchased to address the manufacturer's recommended maintenance practices. Mill Creek Unit 3's generator stator had a "re-wedge" performed in spring 2011.
- During all major generator outages involving General Electric ("GE") machines, a "top tooth" inspection on the rotor will be performed using various techniques to

address GE TIL 1292, which identified potential long term cracking in certain machine designs.

- As part of the Companies' ongoing turbine inspection and maintenance program, all turbine inlet snout rings will be inspected and refurbished during turbine overhauls.
- Additionally, starting in 2011, all of the coal units in the fleet have been subject to on-line monitoring for reliability and efficiency. This service is provided by Black and Veatch, who receives data from our corporate data historian, which is fed by all of the plants. Black and Veatch monitors equipment operations and notifies the plants when there are issues involving reliability or performance, and then works with the plants to resolve the issues.

***Combustion Turbines***

Since the 2011 IRP, the Companies executed significant efforts to maintain the combustion turbine fleet, with the goals of improving reliability and maintaining efficiency. Trimble County CTs 5 – 10 each had a hot gas path inspection (HGPI) since the beginning of 2011. The HGPI is a thorough inspection and, if needed, repair of the components of the combustion turbine from the air inlet section to the exhaust section. All components of the combustor, and turbine sections are included. Additionally, CT 8 at Trimble County had new blades installed on the turbine section to repair known damage and return it to base efficiency. The improvements at the Trimble County site were not limited to mechanical components. Ground fault protection was installed at the site as well for all 6 units, and the batteries were upgraded.

Similar efforts were conducted at the Brown CT site. Brown 8-11 (the 11N2 class machines) underwent upgrades to the controls in 2011 and 2012, similar to controls upgrades previously mentioned earlier on coal units. Turbine blades on CT11 at Brown were repaired due to a heat shield issue, identified in a technical bulletin from the manufacturer. CT9 underwent a hot gas path inspection and overhaul. Other improvements at the Brown CT site included upgrading the 480V switchgear on Brown 6 and 7 (the GT24 class machines), and corrosion monitoring on the fuel lines. These projects enable improved electrical efficiency and reliable fuel transport, respectively.

At the Paddy's Run site, a diesel generator was installed at CT12 for emergency startup and back up auxiliary power. This project supports the reliability of the Paddy's Run site by maintaining availability with diesel auxiliary power in the event of electrical feed issues.

***Hydroelectric Units***

A complete renovation is ongoing at the Ohio Falls station. This 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 nameplate capacity from 10 MW to 12.582 MW and will increase the operating run times. This project is discussed in more detail below.

At the Dix Dam hydro site, Units 1 and 2 underwent complete overhauls in 2011 and 2012, respectively. This included refurbishment of the turbines and generators as well as the wicket gates and runners for both units. Additionally, Unit 2 had the inlet 'Johnson' valve replaced due to the likelihood of failure to this vintage of valve. Significant work was also completed to remediate leakage through the face slab joints of the dam. All these efforts improve the reliability and efficiency of the Dix Dam Hydro site.

***Rehabilitation of Ohio Falls***

The Ohio Falls Station was granted a 40-year operational license by the FERC effective October 25, 2005. 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 and Unit 6 in October 2006 and January 2008, respectively. The rehabilitation project was delayed until 2011 when work began on the next unit. Since 2011, rehabilitation has been completed on Units 1, 3, and 5.

Total rehabilitation of all eight units will increase the expected summer net 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 a potential increase of 187 GWh in annual energy production. The impact of the rehabilitation program is reflected in all of the expansion plan analyses in this IRP.

***New Environmental Projects and Impact***

Since the 2011 IRP, the Companies began several major construction projects to comply with air quality and other environmental standards. These projects include:

- New Flue Gas Desulfurization Units (FGDs) for Mill Creek 1-4.
- New bag houses for Mill Creek 1-4, Ghent 1-4, Brown 3, and Trimble County 1.
- New mercury controls for Brown 1 and 2.

- New coal combustion residual transport systems at Ghent and Brown.
- New combined cycle generating unit at Cane Run.

However, potential efficiency penalties are associated with some of these projects. Environmental control projects require the installation of large equipment for continued environmental compliance. Equipment in this category includes Selective Catalytic Reduction Units (SCRs), Flue Gas Desulfurization Units (FGDs), bag houses, and precipitators. This equipment typically involves larger amounts of ductwork and larger system pressure drops from the boiler to the stack. Generally, this requires larger fans to move the flue gas, which in turn requires more power, increases auxiliary usage of the unit's generation, and lowers overall unit efficiency. Precipitators and FGD systems require electrical power consumption for their components in addition to the extra fan capacity. In these cases, the electrical power usage is managed as efficiently as possible with variable frequency drives on motors, higher efficiency motors, pumps and fans, and more efficient electrical components. However, even the most efficient environmental equipment adds to the auxiliary power consumption for the unit, which lowers the available net power output for a given amount of fuel burned. The efficiency benefits gained through other measures can sometimes be negated by the adverse net power effects of the equipment installed for environmental compliance.

**Transmission**

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 established with other utilities increase the reliability of the transmission system and 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 their transmission system to meet projected customer demands. In compliance with the FERC Standards of Conduct, these projects are provided separately in Transmission Information of Volume III, Technical Appendix of this Plan.

**Distribution**

Common practices, guidelines, and standards are used to manage the Companies' distribution system. The distribution system has been enhanced over the years through the construction of new substations and distribution lines, as well as the expansion and/or enhancement of existing substations and distribution lines, to meet growing customer loads and to improve service reliability and quality.

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

The Companies have completed projects to install, upgrade, or replace distribution substation transformers in 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 five such projects were completed in 2012 and a total of six projects are planned for the years 2014 to 2016. Due to weak economic growth, load growth has slowed. More attention has shifted to reliability and aging infrastructure projects rather than capacity enhancement projects. Projects that improve the worst performing circuits have also received more emphasis.

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

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

The Companies are currently seeking approval for enhancements to the Commission approved Case No. 2011-00134 DSM programs through their pending Case No. 2014-00003. In Case No. 2014-00003, the Companies are seeking to enhance their Commercial Load Management/ Demand Conservation Program to offer customizable demand response options to large commercial customers and educational entities while targeting lighting, HVAC, and other equipment that can provide demand savings. A complete discussion of the Companies' demand-side management programs is contained in Section 8.(5)(a).

## 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 various supply-side technology options were carefully examined as part of the Companies' resource assessment. Table 8.(2)(c) lists the technology options that were evaluated. Additional detail on this process is contained in Volume III, Technical Appendix (see report titled *2014 Resource Assessment*).

To meet customers' long-term needs for capacity and energy, the Companies issued an RFP in September 2012 to 165 marketers, project developers, generation asset owners, and utilities. Several Kentucky utilities responded with proposals. These proposals were evaluated and not found to be part of the least-cost plan for meeting the Companies' capacity and energy needs in 2018 and beyond.

**Table 8.(2)(c) – Generation Technology Options Summary**

| | Operating Characteristics | | | Costs ($2013) | | |
|---|---|---|---|---|---|---|
| **Representative Technology Option** | **Fuel Type** | **Capacity MW** | **Heat Rate Btu/kWh** | **Capital $/kW** | **FO&M $/kW-yr** | **VO&M $/MWh** |
| Simple-cycle GE LM6000 – One Unit | Gas | 49 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE LM6000 – Four Units | Gas | 195 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE LMS100 – One Unit | Gas | 106 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE LMS100 – Two Units | Gas | 211 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE 7EA – One Unit | Gas | 87 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE 7EA – Three Units | Gas | 260 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE 7F-5 – One Unit | Gas | 211 | [redacted] | [redacted] | [redacted] | [redacted] |
| Simple-cycle GE 7F-5 – Three Units | Gas | 634 | [redacted] | [redacted] | [redacted] | [redacted] |
| Recip Engine - 100 MW – Six Units | Gas | 100 | [redacted] | [redacted] | [redacted] | [redacted] |
| Recip Engine - 200 MW_– Twelve Units | Gas | 200 | [redacted] | [redacted] | [redacted] | [redacted] |
| Microturbine- 1 MW – Five Units | Gas | 1 | [redacted] | [redacted] | [redacted] | [redacted] |
| Microturbine - 3 MW – Fifteen Units | Gas | 3 | [redacted] | [redacted] | [redacted] | [redacted] |
| Fuel Cell - 10 MW – Four Units | Gas | 11 | [redacted] | [redacted] | [redacted] | [redacted] |
| Fuel Cell - 30 MW – Twelve Units | Gas | 34 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 GE 7F-5 | Gas | 315 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 GE 7F-5 - Fired | Gas | 357 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 MHI GAC | Gas | 397 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 MHI GAC - Fired | Gas | 452 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 MHI JAC | Gas | 441 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 1x1 MHI JAC - Fired | Gas | 503 | [redacted] | [redacted] | [redacted] | [redacted] |
| Combined Cycle 2x1 GE 7F-5 | Gas | 638 | [redacted] | [redacted] | [redacted] | [redacted] |

| Representative Technology Option | Operating Characteristics Fuel Type | Capacity MW | Heat Rate Btu/kWh | Costs ($2013) Capital $/kW | FO&M $/kW-yr | VO&M $/MWh |
|---|---|---|---|---|---|---|
| Combined Cycle 2x1 GE 7F-5 - Fired | Gas | 719 | [redacted] | | | |
| Combined Cycle 2x1 MHI GAC | Gas | 796 | [redacted] | | | |
| Combined Cycle 2x1 MHI GAC - Fired | Gas | 901 | [redacted] | | | |
| Combined Cycle 2x1 MHI JAC | Gas | 884 | [redacted] | | | |
| Combined Cycle 2x1 MHI JAC - Fired | Gas | 1,003 | [redacted] | | | |
| Combined Cycle 3x1 GE 7F-5 | Gas | 960 | [redacted] | | | |
| Combined Cycle 3x1 GE 7F-5 - Fired | Gas | 1,082 | [redacted] | | | |
| Combined Cycle 3x1 MHI GAC | Gas | 1,199 | [redacted] | | | |
| Combined Cycle 3x1 MHI GAC - Fired | Gas | 1,356 | [redacted] | | | |
| Combined Cycle 3x1 MHI JAC | Gas | 1,330 | [redacted] | | | |
| Combined Cycle 3x1 MHI JAC - Fired | Gas | 1,509 | [redacted] | | | |
| Subcritical Pulverized Coal | Coal | 500 | [redacted] | | | |
| Subcritical Pulverized Coal with CC | Coal | 425 | [redacted] | | | |
| Circulating Fluidized Bed | Coal | 500 | [redacted] | | | |
| Circulating Fluidized Bed with CC | Coal | 425 | [redacted] | | | |
| Supercritical Pulverized Coal | Coal | 500 | [redacted] | | | |
| Supercritical Pulverized Coal with CC | Coal | 425 | [redacted] | | | |
| Supercritical Pulverized Coal | Coal | 750 | [redacted] | | | |
| Supercritical Pulverized Coal with CC | Coal | 638 | [redacted] | | | |
| 2x1 Integrated Gasification | Coal | 618 | [redacted] | | | |
| 2x1 Integrated Gasification with CC | Coal | 482 | [redacted] | | | |
| MSW Stoker Fired | MSW | 50 | [redacted] | | | |
| RDF Stoker Fired | RDF | 50 | [redacted] | | | |
| Wood Stoker Fired | Biomass | 50 | [redacted] | | | |
| Landfill Gas IC Engine | LFG | 5 | [redacted] | | | |
| Anaerobic Digester Gas IC Engine | Sewage | 5 | [redacted] | | | |
| Co-fired Circulating Fluidized Bed | Coal/Biomass | 50 | [redacted] | | | |
| Co-fired Circulating Fluidized Bed | Coal/TDF | 50 | [redacted] | | | |
| Pumped Hydro Energy Storage | Charging | 200 | [redacted] | | | |
| Adv. Battery Energy Storage | Charging | 10 | [redacted] | | | |
| CAES | Gas/Charging | 135 | [redacted] | | | |
| Wind | No Fuel | 50 | [redacted] | | | |
| Solar Photovoltaic | No Fuel | 50 | [redacted] | | | |
| Solar Thermal | No Fuel | 50 | [redacted] | | | |
| Hydro Electric | No Fuel | 50 | [redacted] | | | |

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

Before acting on a decision to build physical capacity, the Companies use an RFP process to obtain offers from the electric market for specific power needs. The Companies distribute the RFP to a broad set of market participants both in Kentucky and throughout the eastern U.S., thus ensuring the opportunity to discover least-cost options for power supply. This process supports the Companies' reliable supply of least-cost energy to customers.

To meet customers' long-term needs for capacity and energy, the Companies issued an RFP in September 2012 to 165 marketers, project developers, generation asset owners, and utilities. Twenty-nine companies responded to the RFP with 72 proposals. The majority of RFP responses included power purchase agreements and new asset development offers for gas-fired technologies (coal, wind, biomass, and solar technologies were also included).

In addition to the RFP responses, the Companies developed five self-build alternatives and evaluated seven DSM programs. In January 2014, based on their analysis of RFP responses and self-build options, the Companies submitted an application for Certificates of Public Convenience and Necessity to the Kentucky Public Service Commission for the construction of (a) a solar photovoltaic ("PV") facility at the E.W. Brown station in 2016 and (b) a natural gas combined cycle ("NGCC") unit at the Green River station in 2018. The proposed solar PV and NGCC facilities, along with Cane Run 7, complete the Companies' expansion plan through 2018.

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

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

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

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

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

The requested information for subparts 1-11, 12d, and 12f is included in the following pages for existing units as well as Cane Run 7, Brown Solar, and Green River 5. In the expansion planning analysis, the Companies developed optimal expansion plans over multiple natural gas price, load, and $CO_2$ scenarios. For each of the scenarios evaluated, the requested information for the remaining subparts is summarized in *Appendix to Sections 8 and 9 – Scenario Data* (see Volume III, Technical Appendix).

# Table 8.(3)(b) 1-11
## KU and LG&E Existing and Planned Electric Generation Facilities

| 1 | 2 | 3 | 4 | 5 | 6 | 7 | | 8 | | 9 | 10 | 11 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Plant Name | Unit No. | Location in Kentucky | Status | Operation Date | Facility Type | Net Capability (MW)* 2014/15 Winter | 2014 Summer | Entitlement KU | LGE | Fuel Type | Fuel Storage Cap/SO₂ Content | Scheduled Upgrades Derates, Retirements |
| Cane Run | 4 | Louisville | Existing | 1962 | Steam | 155 | 155 | | 100% | Coal (Rail) | 350,000 Tons (6.0# SO2) | Assumed to retire 2015 |
| | 5 | | | 1966 | | 168 | 168 | | | | | |
| | 6 | | | 1969 | | 240 | 240 | | | | | |
| | 11 | | | 1968 | Turbine | 14 | 14 | | | Gas / Oil | 50,000 Gals | None |
| Dix Dam | 1-3 | Burgin | Existing | 1925 | Hydro | 24 | 24 | 100% | | Water | None | None |
| E. W. Brown Coal | 1 | Burgin | Existing | 1957 | Steam | 107 | 106 | 100% | | Coal (Rail) | 360,000 Tons (6# SO2) | None |
| | 2 | | | 1963 | | 168 | 166 | | | | | None |
| | 3 | | | 1971 | | 414 | 410 | | | | | Baghouse Derate 2015 |
| E.W. Brown-ABB 11N2 | 5 | | | 2001 | Turbine | 130 | 133 | 47% | 53% | Gas | 2,200,000 Gals | None |
| E.W. Brown-ABB GT24 | 6 | | | 1999 | | 171 | 146 | 62% | 38% | Gas / Oil | | |
| | 7 | | | 1999 | | 171 | 146 | | | | | |
| E.W. Brown-ABB 11N2 | 8 | | | 1995 | | 128 | 121 | 100% | | | | |
| | 9 | | | 1994 | | 138 | 121 | | | | | |
| | 10 | | | 1995 | | 138 | 121 | | | | | |
| | 11 | | | 1996 | | 128 | 121 | | | | | |
| Ghent | 1 | Ghent | Existing | 1974 | Steam | 481 | 479 | 100% | | Coal (Barge) | 1,300,000 Tons (6# SO2) | Baghouse Derate 2015 |
| | 2 | | | 1977 | | 477 | 495 | | | | | Baghouse Derate 2015 |
| | 3 | | | 1981 | | 482 | 489 | | | | | Baghouse Derate 2014 |
| | 4 | | | 1984 | | 491 | 469 | | | | | Baghouse Derate 2014 |
| Green River | 3 | Central City | Existing | 1954 | Steam | 71 | 68 | 100% | | Coal | 150,000 Tons (4.5# SO2) | Assumed to retire 2015 |
| | 4 | | | 1959 | | 98 | 93 | | | | | |
| Haefling | 1 | Lexington | Existing | 1970 | Turbine | 14 | 12 | 100% | | Gas / Oil | 130,000 Gals | None |
| | 2 | | | 1970 | | 14 | 12 | | | | | |
| Mill Creek | 1 | Louisville | Existing | 1972 | Steam | 303 | 303 | | 100% | Coal (Barge & Rail) | 1,000,000 Tons (6# SO2) | Baghouse Derate 2015 |
| | 2 | | | 1974 | | 299 | 301 | | | | | Baghouse Derate 2015 |
| | 3 | | | 1978 | | 394 | 391 | | | | | Baghouse Derate 2016 |
| | 4 | | | 1982 | | 486 | 477 | | | | | Baghouse Derate 2014 |
| Ohio Falls | 1-8 | Louisville | Existing | 1928 | Hydro | Run of River (35/54) | | | 100% | Water | None | 10 MW upgrade 2014-2017 |
| Paddy's Run | 11 | Louisville | Existing | 1968 | Turbine | 13 | 12 | | 100% | Gas | None | None |
| | 12 | | | 1968 | | 28 | 23 | | | | | |
| Paddy's Run- Siem/West V84.3a | 13 | | | 2001 | | 175 | 147 | 47% | 53% | | | |
| Trimble County Coal (75%) | 1 | Near Bedford | Existing | 1990 | Steam | 511 (383) | 511 (383) | 0% | 75% | Coal (Barge) | 1,000,000 Tons (6.0# SO2) | Baghouse Derate 2015 |
| | 2 | | | 2011 | | 760 (570) | 732 (549) | 61% | 14% | | 150,000 Tons (0.6# SO2) | None |
| Trimble County-GE7FA | 5 | | | 2002 | Turbine | 176 | 157 | 71% | 29% | Gas | None | None |
| | 6 | | | 2002 | | 176 | 157 | | | | | |
| | 7 | | | 2004 | | 176 | 157 | 63% | 37% | | | |
| | 8 | | | 2004 | | 176 | 157 | | | | | |
| | 9 | | | 2004 | | 176 | 157 | | | | | |
| | 10 | | | 2004 | | 176 | 157 | | | | | |
| Zorn | 1 | Louisville | Existing | 1969 | Turbine | 16 | 14 | | 100% | Gas | None | None |
| **Future Units** | | | | | | | | | | | | |
| Cane Run | 7 | Louisville | Under Const. | 2015 | Turbine | 652 | 640 | 78% | 22% | Gas | None | None |
| E.W. Brown Solar | 1 | Burgin | Proposed | 2016 | Solar | 0 | 9 | 64% | 36% | Solar | None | None |
| Green River | 5 | Central City | Proposed | 2018 | Turbine | 657 | 670 | 60% | 40% | Gas | None | None |

* The ratings for Dix Dam, Ohio Falls, and E. W. Brown Solar reflect the assumed output for these facilities during the summer and winter peak demands.

**Table 8.(3)(b) 12(d),(f)**
**Kentucky Utilities Company / Louisville Gas & Electric Company**
**Capital Cost and Escalation Factors**

| | Cane Run 7 | Brown Solar | Green River 5 | 2x1 Combined Cycle | 1x1 Combined Cycle | Simple Cycle CT | Three Simple Cycle CTs | Wind Turbine | Solar Photovoltaic |
|---|---|---|---|---|---|---|---|---|---|
| Capital Costs ($/kW)[1] | [redacted] | | | | | | | | |
| Total Capital Costs ($000s)[2] | | | | | | | | | |
| Capital Escalation Factor (%) | NA | NA | NA | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| Variable O&M Escalation Factor (%)[3] | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| Fixed O&M Escalation Factor (%)[3] | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |

1. Capital cost ($/kW) was computed based on summer rating.
2. Capital cost for Cane Run 7 is the sum of nominal as-spent dollars. Capital costs for Brown Solar and Green River 5 are in 2018 "overnight" dollars. Capital costs for the remaining units are in 2013 "overnight" dollars.
3. Fixed and variable escalation factors also apply to existing units.

**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.**

In 2013, the Companies' non-firm purchases and off-system sales totaled 105 GWh and 503 GWh, respectively. In addition, the Companies purchased 854 GWh through their power purchase agreement with OVEC. The IRP analysis assumes the Companies have no access to short-term power purchases from the market and make no off-system sales. These assumptions focus the analysis on finding the best resource for serving the Companies' native load and eliminate the need to speculate on future power prices. For each of the scenarios evaluated, Table 8.(3)(c) summarizes the level of purchases from OVEC over the analysis period. Table 8.(3)(c) excludes any capacity additions for 2015 through 2017 as these additions have not been identified.

**Table 8.(3)(c)**
**OVEC Purchases (GWh)**

| Scenario | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mid Gas-Low Load-Zero Carbon | 699 | 1,333 | 1,357 | 1,372 | 1,390 | 1,383 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| Mid Gas-Low Load-Mid Carbon | 699 | 1,333 | 1,357 | 1,372 | 1,390 | 1,383 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| Mid Gas-Low Load-Carbon Cap | 699 | 1,333 | 1,357 | 1,372 | 1,390 | 1,383 | 1,394 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| Mid Gas-High Load-Zero Carbon | 861 | 1,363 | 1,382 | 1,385 | 1,391 | 1,388 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| Mid Gas-Base Load-Zero Carbon | 772 | 1,348 | 1,372 | 1,381 | 1,391 | 1,387 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| Mid Gas-Base Load-Mid Carbon | 772 | 1,348 | 1,372 | 1,381 | 1,391 | 1,387 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| Mid Gas-Base Load-Carbon Cap | 772 | 1,348 | 1,372 | 1,381 | 1,391 | 1,387 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| Low Gas-Low Load-Zero Carbon | 474 | 852 | 1,240 | 1,216 | 1,176 | 1,119 | 1,137 | 1,196 | 1,153 | 1,245 | 1,214 | 1,293 | 1,217 | 1,297 | 1,303 |
| Low Gas-Low Load-Mid Carbon | 474 | 852 | 1,240 | 1,216 | 1,176 | 1,119 | 1,393 | 1,390 | 1,389 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| Low Gas-Low Load-Carbon Cap | 474 | 852 | 1,240 | 1,216 | 1,176 | 1,119 | 1,137 | 1,196 | 1,153 | 1,245 | 1,214 | 1,293 | 1,217 | 1,297 | 1,303 |
| Low Gas-High Load-Zero Carbon | 525 | 1,034 | 1,301 | 1,296 | 1,278 | 1,129 | 1,028 | 1,105 | 1,067 | 1,173 | 1,137 | 1,220 | 1,034 | 972 | 1,010 |
| Low Gas-Base Load-Zero Carbon | 493 | 947 | 1,268 | 1,266 | 1,237 | 1,176 | 1,188 | 1,250 | 1,205 | 1,290 | 1,264 | 1,243 | 1,062 | 1,141 | 1,179 |
| Low Gas-Base Load-Mid Carbon | 493 | 947 | 1,268 | 1,266 | 1,237 | 1,176 | 1,394 | 1,386 | 1,360 | 1,369 | 1,373 | 1,391 | 1,391 | 1,391 | 1,395 |
| Low Gas-Base Load-Carbon Cap | 493 | 947 | 1,268 | 1,266 | 1,237 | 1,176 | 1,055 | 1,018 | 973 | 1,101 | 1,036 | 1,123 | 1,062 | 1,141 | 1,179 |
| High Gas-Low Load-Zero Carbon | 713 | 1,343 | 1,395 | 1,390 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| High Gas-Low Load-Mid Carbon | 713 | 1,343 | 1,395 | 1,390 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| High Gas-Low Load-Carbon Cap | 713 | 1,343 | 1,395 | 1,390 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| High Gas-High Load-Zero Carbon | 887 | 1,368 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| High Gas-Base Load-Zero Carbon | 793 | 1,355 | 1,395 | 1,390 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| High Gas-Base Load-Mid Carbon | 793 | 1,355 | 1,395 | 1,390 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |
| High Gas-Base Load-Carbon Cap | 793 | 1,355 | 1,395 | 1,390 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 | 1,391 | 1,391 | 1,391 | 1,395 |

**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 IRP does not include purchases from non-utility sources.

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

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

**Residential Customer Class**

***Residential Load Management / Demand Conservation Program (Approved and Unchanged)***

As approved in Case No. 2011-00134, this program cycles residential central air conditioning units, water heaters, and residential pool pumps of both LG&E and KU customers. It is designed to provide customers with an incentive to allow the Companies to interrupt service to their equipment at those peak demand periods when the Companies need additional resources to meet customer demand.

***Residential Conservation / Home Energy Performance Program (Enhanced Program)***

This program targets customers who own or occupy single-family homes, apartments or condominiums. It is designed to provide customers with an on-site home energy audit that will provide opportunities for improved energy efficiency ("EE"). In Case No. 2014-00003, the Companies are seeking approval to implement an incentive structure for multi-family properties as well as insulation and weatherization efforts.

***Residential Low Income Weatherization Program (Approved and Unchanged)***

As approved in Case No. 2011-00134, this program is designed to reduce the energy bills of low income customers by weatherizing their homes. This program is available to "Low Income Home Energy Assistance Program" (LIHEAP) eligible customers.

***Residential Smart Energy Profile (Approved and Unchanged)***

As approved in Case No. 2011-00134, the objective of the Smart Energy Profile Program is to provide approximately 50 percent of residential customers of LG&E and KU with a customized report based on individual household energy consumption over the first four years of the program. These reports are benchmarked against similar properties by size, type, number of residents and location. Additional tips and EE programming recommendations are provided to educate and encourage behavior change.

***Residential Incentives Program (Enhanced Program)***

The Residential Incentives Program is designed to provide direct financial incentives to encourage customers to purchase various Energy Star appliances, HVAC equipment, or window films that meet certain requirements. To address the exceedingly high customer participation and prevent early program termination, the Companies are seeking approval in Case No. 2014-00003 to increase incentive dollars available to customers that will fund the program through 2018, consistent with the original filing for this program.

***Residential Refrigerator Removal Program (Approved and Unchanged)***

As approved in Case No. 2011-00134, the Refrigerator Removal Program is designed to provide removal and recycling of inefficient secondary refrigerators and freezers from LG&E and KU customer households. The removal of these inefficient units will reduce energy consumption and demand.

**Commercial Customer Class**

***Commercial Load Management / Demand Conservation Program (Enhanced Program)***

This program cycles commercial central air conditioning units, water heaters, and commercial pool pumps of both LG&E and KU customers. It is designed to provide customers with an incentive to allow the Companies to interrupt service to their central air conditioners, water heaters, and/or pool pumps at those peak demand periods when the Companies need additional resources to meet customer demand. In Case No. 2014-00003, the Companies are seeking approval for a full deployment of a large commercial load management effort; and the ability to modify financial incentives to encourage customers to participate in this voluntary program.

***Commercial Conservation / Commercial Incentives Program (Enhanced Program)***

This program is offered to all commercial class customers. The objective is to identify energy efficiency opportunities for commercial class customers and assist them in the implementation of these identified energy efficiency opportunities. In Case No. 2014-00003, the Companies are seeking the elimination of the on-site commercial audit; further development of their online audit tool as well as additional special-purpose energy tools to support commercial customers; and rebates for new construction efforts where efficiency is above the standard building code.

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

The Companies are seeking approval for enhancements to programming in their currently approved portfolio from Case No. 2011-00134 and the continuation of one program in approved Case No. 2007-00319. The program enhancements will take into account aspects of certain programming that is set to expire December 31, 2014 in Case No. 2007-00319. The proposal in front of the Commission in Case No. 2014-00003 will allow the Companies to align their DSM/EE portfolio with all approved programs ending in 2018.

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

Load changes for the existing and future rate programs are embedded in the load forecast for energy and demand presented throughout this report. Table 8.(3)(e)(3)-1 summarizes the annual incremental energy impact and the summer and winter peak demand of the LG&E and KU interruptible rate and the future programs. Table 8.(3)(e)(3)-2 summarizes the cumulative energy impact and the summer and winter peak demand of the LG&E and KU interruptible rate and the future programs.

Beyond 2018, the programs do not further reduce energy and demand. The Companies commissioned The Cadmus Group, Inc. ("Cadmus") to perform an Energy Efficiency Potential Study ("EE Potential Study"). The EE Potential Study involved separate assessments of energy-efficiency potential for electricity and natural gas in the residential and commercial sectors, considering a wide range of energy-efficiency technologies. As noted in the EE Potential Study, the Companies are currently on track to exhaust their *achievable* energy-efficiency potential by 2018. Nonetheless, the Companies will continue to monitor the energy-efficiency marketplace to explore new technologies and opportunities to reduce energy and demand where economically feasible and will consider new or revised DSM/EE programs through 2018 and beyond.

# Table 8.(3)(e)(3)-1
# Louisville Gas and Electric Company / Kentucky Utilities Company/
# Demand Side Management Energy and Demand Impacts (Incremental)

| DSM Energy Reduction (GWh) | Status | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential High Efficiency Lighting | Expiring | 48.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential New Construction | Expiring | 2.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential HVAC Tune Up | Expiring | 1.1 | 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 HVAC Tune Up | Expiring | 2.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Dealer Referral Network | Expiring | 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 |
| | | | | | | | | | | | | | | | | |
| Smart Energy Profile | Existing | 58.1 | 106.5 | 106.5 | 106.5 | 106.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Load Management | Existing | 3.2 | 3.2 | 2.7 | 2.7 | 2.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Refrigerator Removal | Existing | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Low Income Weatherization | Existing | 4.8 | 5.9 | 7.0 | 8.1 | 9.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Program Development & Administration | Existing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | | | | | | | | | | | | | | | |
| Commercial Load Management | Enhanced | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Incentives | Enhanced | 16.3 | 25.2 | 25.2 | 25.2 | 25.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Customer Education & Public Information | Enhanced | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Conservation (HEPP) | Enhanced | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Commercial Conservation/Rebates | Enhanced | 55.0 | 42.6 | 42.6 | 44.0 | 44.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | | | | | | | | | | | | | | | |
| AMI | New | 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 Annual Energy Reduction | All | 205.1 | 196.1 | 196.7 | 199.2 | 200.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

# Table 8.(3)(e)(3)-1 Continued

| DSM Summer Peak Demand Reduction (MW) | Status | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential High Efficiency Lighting | Expiring | 3.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential New Construction | Expiring | 0.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential HVAC Tune Up | Expiring | 0.5 | 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 |
| Commercial HVAC Tune Up | Expiring | 0.5 | 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 |
| Dealer Referral Network | Expiring | 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 |
| | | | | | | | | | | | | | | | | |
| Smart Energy Profile | Existing | 11.1 | 20.3 | 20.3 | 20.3 | 20.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Load Management | Existing | 12.3 | 11.2 | 9.3 | 9.3 | 9.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Refrigerator Removal | Existing | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Low Income Weatherization | Existing | 0.5 | 0.6 | 0.7 | 0.8 | 0.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Program Development & Administration | Existing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | | | | | | | | | | | | | | | |
| Commercial Load Management | Enhanced | 0.9 | 5.1 | 5.1 | 5.1 | 5.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Incentives | Enhanced | 3.0 | 4.1 | 4.1 | 4.1 | 4.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Customer Education & Public Information | Enhanced | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Conservation (HEPP) | Enhanced | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Commercial Conservation/Rebates | Enhanced | 20.7 | 15.7 | 15.7 | 16.0 | 16.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | | | | | | | | | | | | | | | |
| AMI | New | 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 Annual Demand Reduction | All | 55.7 | 59.2 | 57.5 | 57.8 | 57.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

## Table 8.(3)(e)(3)-1 Continued

| DSM Winter Peak Demand Reduction (MW) | Status | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential High Efficiency Lighting | Expiring | 6.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential New Construction | Expiring | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential HVAC Tune Up | Expiring | 0.1 | 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 HVAC Tune Up | Expiring | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Dealer Referral Network | Expiring | 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 |
| | | | | | | | | | | | | | | | | |
| Smart Energy Profile | Existing | 9.7 | 24.8 | 24.8 | 24.8 | 24.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Load Management | Existing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Refrigerator Removal | Existing | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Low Income Weatherization | Existing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Program Development & Administration | Existing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | | | | | | | | | | | | | | | |
| Commercial Load Management | Enhanced | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Incentives | Enhanced | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Customer Education & Public Information | Enhanced | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Conservation (HEPP) | Enhanced | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Commercial Conservation/Rebates | Enhanced | 7.2 | 7.2 | 7.2 | 7.4 | 7.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | | | | | | | | | | | | | | | |
| AMI | New | 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 Existing Programs | All | 28.2 | 36.1 | 36.1 | 36.3 | 36.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

**Table 8.(3)(e)(3)-2**
**Louisville Gas and Electric Company / Kentucky Utilities Company/**
**Demand Side Management Energy and Demand Impacts (Cumulative)**

| DSM Energy Reduction (GWh) | Status | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential High Efficiency Lighting | Expiring | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 | 340.2 |
| Residential New Construction | Expiring | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 | 16.4 |
| Residential HVAC Tune Up | Expiring | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 | 4.2 |
| Commercial HVAC Tune Up | Expiring | 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 |
| Dealer Referral Network | Expiring | 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 |
| | | | | | | | | | | | | | | | | | |
| Smart Energy Profile | Existing | 138.0 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 | 106.5 |
| Residential Load Management | Existing | 0.0 | 3.2 | 5.9 | 8.5 | 11.2 | 11.2 | 11.2 | 11.2 | 11.2 | 11.2 | 11.2 | 11.2 | 11.2 | 11.2 | 11.2 | 11.2 |
| Residential Refrigerator Removal | Existing | 12.8 | 20.8 | 28.7 | 36.7 | 44.6 | 44.6 | 44.6 | 44.6 | 44.6 | 44.6 | 44.6 | 44.6 | 44.6 | 44.6 | 44.6 | 44.6 |
| Residential Low Income Weatherization | Existing | 28.4 | 34.4 | 41.4 | 49.5 | 58.7 | 58.7 | 58.7 | 58.7 | 58.7 | 58.7 | 58.7 | 58.7 | 58.7 | 58.7 | 58.7 | 58.7 |
| Program Development & Administration | Existing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | | | | | | | | | | | | | | | | |
| Commercial Load Management | Enhanced | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Incentives | Enhanced | 30.4 | 55.6 | 80.8 | 106.0 | 131.3 | 131.3 | 131.3 | 131.3 | 131.3 | 131.3 | 131.3 | 131.3 | 131.3 | 131.3 | 131.3 | 131.3 |
| Customer Education & Public Information | Enhanced | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Conservation (HEPP) | Enhanced | 23.6 | 28.8 | 33.9 | 39.1 | 44.2 | 44.2 | 44.2 | 44.2 | 44.2 | 44.2 | 44.2 | 44.2 | 44.2 | 44.2 | 44.2 | 44.2 |
| Commercial Conservation/Rebates | Enhanced | 237.1 | 279.7 | 322.4 | 366.4 | 410.4 | 410.4 | 410.4 | 410.4 | 410.4 | 410.4 | 410.4 | 410.4 | 410.4 | 410.4 | 410.4 | 410.4 |
| | | | | | | | | | | | | | | | | | |
| AMI | New | 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 |
| Total Annual Energy Reduction | All | 832.7 | 891.3 | 981.9 | 1,075.1 | 1,169.3 | 1,169.3 | 1,169.3 | 1,169.3 | 1,169.3 | 1,169.3 | 1,169.3 | 1,169.3 | 1,169.3 | 1,169.3 | 1,169.3 | 1,169.3 |

## Table 8.(3)(e)(3)-2 Continued

| DSM Summer Peak Demand Reduction (MW) | Status | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential High Efficiency Lighting | Expiring | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 | 26.2 |
| Residential New Construction | Expiring | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 |
| Residential HVAC Tune Up | Expiring | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 |
| Commercial HVAC Tune Up | Expiring | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| Dealer Referral Network | Expiring | 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 |
| | | | | | | | | | | | | | | | | | |
| Smart Energy Profile | Existing | 11.1 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 | 20.3 |
| Residential Load Management | Existing | 165.4 | 176.7 | 186.0 | 195.3 | 204.7 | 204.7 | 204.7 | 204.7 | 204.7 | 204.7 | 204.7 | 204.7 | 204.7 | 204.7 | 204.7 | 204.7 |
| Residential Refrigerator Removal | Existing | 1.9 | 2.8 | 3.7 | 4.6 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 |
| Residential Low Income Weatherization | Existing | 1.9 | 2.5 | 3.2 | 4.0 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 |
| Program Development & Administration | Existing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | | | | | | | | | | | | | | | | |
| Commercial Load Management | Enhanced | 16.8 | 21.8 | 26.9 | 32.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 |
| Residential Incentives | Enhanced | 8.7 | 12.8 | 16.8 | 20.9 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| Customer Education & Public Information | Enhanced | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Conservation (HEPP) | Enhanced | 5.6 | 6.9 | 8.2 | 9.5 | 10.8 | 10.8 | 10.8 | 10.8 | 10.8 | 10.8 | 10.8 | 10.8 | 10.8 | 10.8 | 10.8 | 10.8 |
| Commercial Conservation/Rebates | Enhanced | 93.0 | 108.7 | 124.4 | 140.4 | 156.3 | 156.3 | 156.3 | 156.3 | 156.3 | 156.3 | 156.3 | 156.3 | 156.3 | 156.3 | 156.3 | 156.3 |
| | | | | | | | | | | | | | | | | | |
| AMI | New | 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 |
| Total Annual Demand Reduction | All | 339.9 | 388.0 | 425.2 | 462.6 | 500.2 | 500.2 | 500.2 | 500.2 | 500.2 | 500.2 | 500.2 | 500.2 | 500.2 | 500.2 | 500.2 | 500.2 |

# Table 8.(3)(e)(3)-2 Continued

| DSM Winter Peak Demand Reduction (MW) | Status | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential High Efficiency Lighting | Expiring | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 | 59.7 |
| Residential New Construction | Expiring | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential HVAC Tune Up | Expiring | 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 HVAC Tune Up | Expiring | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Dealer Referral Network | Expiring | 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 |
| | | | | | | | | | | | | | | | | | |
| Smart Energy Profile | Existing | 9.5 | 24.8 | 24.8 | 24.8 | 24.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Load Management | Existing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Refrigerator Removal | Existing | 1.8 | 2.7 | 3.6 | 4.5 | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 |
| Residential Low Income Weatherization | Existing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Program Development & Administration | Existing | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | | | | | | | | | | | | | | | | |
| Commercial Load Management | Enhanced | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Incentives | Enhanced | 4.9 | 7.1 | 9.2 | 11.4 | 13.5 | 13.5 | 13.5 | 13.5 | 13.5 | 13.5 | 13.5 | 13.5 | 13.5 | 13.5 | 13.5 | 13.5 |
| Customer Education & Public Information | Enhanced | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Residential Conservation (HEPP) | Enhanced | 4.9 | 6.0 | 7.0 | 8.1 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 | 9.2 |
| Commercial Conservation/Rebates | Enhanced | 44.1 | 51.3 | 58.5 | 65.8 | 73.2 | 73.2 | 73.2 | 73.2 | 73.2 | 73.2 | 73.2 | 73.2 | 73.2 | 73.2 | 73.2 | 73.2 |
| | | | | | | | | | | | | | | | | | |
| AMI | New | 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 |
| Total Existing Programs | All | 125.0 | 151.5 | 162.8 | 174.3 | 185.8 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 |

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

The projected costs provided below in Table 8.(3)(e)-4 assume a 2014 Commission order for expanded DSM/EE programs with a program implementation in 2015.

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

| Program Expenses ($M) | Status | 2014 | 2015 | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|---|---|
| Residential High Efficiency Lighting | Expiring | $4.5 | $0.0 | $0.0 | $0.0 | $0.0 | $4.5 |
| Residential New Construction | Expiring | $1.4 | $0.0 | $0.0 | $0.0 | $0.0 | $1.4 |
| Residential HVAC Tune Up | Expiring | $0.6 | $0.0 | $0.0 | $0.0 | $0.0 | $0.6 |
| Commercial HVAC Tune Up | Expiring | $0.6 | $0.0 | $0.0 | $0.0 | $0.0 | $0.6 |
| Dealer Referral Network | Expiring | $0.2 | $0.0 | $0.0 | $0.0 | $0.0 | $0.2 |
| | | | | | | | |
| Smart Energy Profile | Existing | $2.2 | $3.3 | $3.3 | $3.4 | $3.5 | $15.8 |
| Residential Load Management | Existing | $11.8 | $13.8 | $13.6 | $14.0 | $14.5 | $67.8 |
| Residential Refrigerator Removal | Existing | $2.0 | $2.0 | $2.1 | $2.2 | $2.2 | $10.4 |
| Residential Low Income Weatherization | Existing | $4.0 | $4.9 | $5.9 | $6.9 | $7.8 | $29.5 |
| Program Development & Administration | Existing | $1.3 | $1.4 | $1.4 | $1.5 | $1.5 | $7.1 |
| | | | | | | | |
| Commercial Load Management | Enhanced | $0.6 | $1.6 | $1.9 | $2.2 | $2.6 | $8.8 |
| Residential Incentives | Enhanced | $2.6 | $4.1 | $4.1 | $4.1 | $4.1 | $19.1 |
| Customer Education & Public Information | Enhanced | $3.6 | $4.0 | $4.1 | $4.2 | $4.3 | $20.3 |
| Residential Conservation (HEPP) | Enhanced | $2.2 | $2.3 | $2.3 | $2.3 | $2.4 | $11.4 |
| Commercial Conservation/Rebates | Enhanced | $3.3 | $3.3 | $3.4 | $3.4 | $3.4 | $16.9 |
| | | | | | | | |
| AMI | New | $0.0 | $0.8 | $1.7 | $1.7 | $1.5 | $5.7 |
| Total Existing Programs | All | $41.0 | $41.6 | $43.7 | $45.9 | $47.8 | $220.1 |

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

The Companies project that over the lives of enhanced and existing/unchanged programs that are in the DSM/EE filing currently in front of the Commission, customers will reduce demand by an aggregated or cumulative 500 MW through 2018 and realize a total energy savings of 200 GWh.

**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' capacity supply/demand balance is summarized in Table 8.(4)(a)-1 and Table 8.(4)(a)-2 for the 15-year planning period in the Base load forecast scenario. As discussed in the Companies' *2014 Reserve Margin Analysis* (see Volume III, Technical Appendix), the Companies target a minimum 16 percent reserve margin (above peak load after adjusting for demand-side management ("DSM") programs) for the purpose of developing expansion plans. The IRP analysis assumes the Cane Run and Green River coal units are retired in 2015. To offset this loss of capacity and energy, the Companies are building Cane Run 7 and have proposed to build Brown Solar by 2016 and Green River 5 by 2018. Considering these changes to the Companies' generation portfolio, along with more than 400 MW of demand reduction from DSM programs by 2018 and 131 MW of curtailable load from curtailable service rider customers, the Companies will have a long-term need for capacity beginning in 2025.

While meeting customers' energy demand at the peak hour is critical, it is also vital to reliably serve their energy needs at all hours at the lowest reasonable cost. In the Base load forecast scenario, energy requirements are forecasted to grow by 3.6 TWh over the next 15 years even after reductions for DSM. See Table 6.1(1)-1 in Section 6 for more information regarding the Companies' load forecast.

The Companies' Resource Assessment for 2019 through 2028 was completed in two parts. First, the Companies performed a screening analysis of more than 50 generation technology options to determine a subset of the most competitive options. Then, this subset of generation technology options was incorporated into a detailed expansion planning analysis to determine optimal expansion plans beyond 2018.

Since the 2011 IRP, resource costs have been generally stable due to the economic slow-down from 2008 through 2012. An abundance of low cost natural gas supply resulting from advancements in natural gas drilling technologies coupled with relatively low capital and operating costs have greatly improved the economics of natural gas combined-cycle technology. Wind capital costs have decreased slightly compared to the 2011 IRP. The capital cost for solar PV has declined more significantly, but this trend is expected to flatten. Overall, the costs of renewable generation remain higher than fossil generation technologies. However, with tax incentives and Renewable Energy Credits ("RECs"), both solar PV and wind technologies can be cost competitive.

In the screening analysis, the levelized cost of the technology options was calculated at various levels of utilization. In addition to the level of utilization (i.e., capacity factor), the levelized cost of each technology option is impacted by the uncertainty in capital cost, fuel cost, unit efficiency, and $CO_2$ emissions. As a result, the technology options were evaluated over three capital cost scenarios, three heat rate scenarios, three fuel scenarios, two $CO_2$ scenarios, and ten capacity factors for a total of 540 cases. Given the uncertainty in REC prices and the availability of investment tax credits ("ITC") for renewable technologies, two iterations of 540 cases were evaluated:

- No ITC or RECs: This iteration did not include an ITC for renewable technologies or wind and solar RECs.
- 10% ITC and RECs: This iteration incorporated a 10 percent ITC and current REC market prices for solar and wind technologies.

Table 8.(4)-1 lists the technology options that were ranked among the top four least-cost technology options in at least one of the 540 cases. In the "No ITC or RECs" iteration, the "2x1 NGCC G/H-Class" option was least-cost in 440 of the 540 cases and ranked among the top four least-cost options in all 540 cases. The option to install three F-Class SCCTs ("SCCT F-Class – Three Units") was least-cost in 100 cases. The "2x1 NGCC G/H-Class" option had the lowest levelized cost for capacity factors exceeding 20 percent and is the best option for meeting intermediate and base load energy needs. The "SCCT F-Class – Three Units" option was least cost for capacity factors below 20 percent and the best choice for meeting peak energy needs. In the "10% ITC and RECs" iteration, the solar PV and wind technology options were ranked among the top four least-cost technology options in multiple cases.

**Table 8.(4)-1**
**Screening Results (Technology Options Ranked Among Top Four Least-Cost)**

| **Generation Technology Option** | **No ITC or RECs** | | | | | **10% ITC and RECs** | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **# Occurrences** | | | | | **# Occurrences** | | | | |
| | **1st** | **2nd** | **3rd** | **4th** | **Total** | **1st** | **2nd** | **3rd** | **4th** | **Total** |
| 2x1 NGCC G/H Class | 440 | 14 | 32 | 54 | **540** | 428 | 21 | 37 | 54 | **540** |
| 2x1 NGCC G/H Class – DF | 0 | 145 | 368 | 27 | **540** | 0 | 131 | 375 | 34 | **540** |
| 2x1 NGCC F Class | 0 | 326 | 95 | 42 | **463** | 0 | 326 | 78 | 53 | **457** |
| 2x1 NGCC F Class – DF | 0 | 0 | 0 | 288 | **288** | 0 | 0 | 0 | 268 | **268** |
| 1x1 NGCC G/H Class | 0 | 0 | 27 | 110 | **137** | 0 | 0 | 27 | 110 | **137** |
| SCCT F Class – Three Units | 100 | 1 | 18 | 5 | **124** | 100 | 1 | 18 | 5 | **124** |
| SCCT F Class – One Unit | 0 | 54 | 0 | 14 | **68** | 0 | 54 | 0 | 14 | **68** |
| Solar Photovoltaic | 0 | 0 | 0 | 0 | **0** | 11 | 1 | 1 | 1 | **14** |
| Wind | 0 | 0 | 0 | 0 | **0** | 1 | 6 | 3 | 1 | **11** |
| Hydro Electric | 0 | 0 | 0 | 0 | **0** | 0 | 0 | 1 | 0 | **1** |

Table 8.(4)-2 lists the generation technology options that were evaluated in the detailed expansion planning analysis. The two F-Class NGCC options, the 2x1 NGCC G/H-Class option with duct firing ("DF"), and the hydroelectric option in Table 8.(4)-1 were ultimately excluded from the detailed analysis. Potential GHG regulation and uncertainty in gas prices make the added efficiency of the G-Class technology option more cost-effective than the F-Class technology option. Additionally, the capital and fixed costs for the G-Class technology option

are lower on a per-kilowatt ("kW") basis. The 2x1 NGCC G/H-Class option with duct firing was consistently less favorable than the 2x1 NGCC G/H-Class option without duct firing.[3] The hydroelectric option was eliminated because it ranked among the top four least-cost options in only one of 540 cases. In addition, the Companies are not aware of any viable sites for new hydroelectric capacity near their service territories.

**Table 8.(4)-2**
**List of Technology Options Evaluated in Expansion Planning Analysis**

| **2013 IRP Generation Technology Options** |
|---|
| 2x1 NGCC G/H Class |
| 1x1 NGCC G/H Class |
| SCCT F Class – Three Units |
| SCCT F Class – One Unit |
| Solar Photovoltaic |
| Wind |

The list of generation technology options in Table 8.(4)-2 is very similar to the list of technology options that passed the screening analysis for the 2011 IRP. Notable exceptions include the 3x1 NGCC technology option and the supercritical pulverized coal ("PC") technology option. The 3x1 NGCC was excluded from the analysis due to its size; it is difficult for the Companies to recover from the loss of such a large unit given the relatively small size of their generating portfolio. The supercritical PC technology option was not ranked among the least-cost technology options due primarily to its high capital cost and a lower forecast of natural gas prices.[4] In addition, currently proposed federal New Source Performance Standards ("NSPS") for GHG regulations would require coal units to eventually be equipped with large

[3] In addition, the 2x1 NGCC options with duct firing are not materially different from the 2x1 NGCC options without duct firing. Duct firing serves as a means to adjust the size and flexibility of a NGCC unit.

[4] Compared to the 2x1 NGCC G/H-Class option, the capital cost ($/kW) for the supercritical PC option is more than five times higher. The price spread between the Mid natural gas price forecast and the coal price forecast is more than 70 percent lower in the 2014 IRP compared to the 2011 IRP.

scale, commercially unproven and currently uneconomic $CO_2$ capture and sequestration technology.

In the expansion planning analysis, the Companies developed optimal expansion plans using the technology options in Table 8.(4)-2 over multiple natural gas price, load, and $CO_2$ scenarios. $CO_2$ scenarios include: 1) a Zero $CO_2$ price scenario, where there is never a price on future $CO_2$ emissions; 2) a Mid $CO_2$ price scenario, where a price on each ton of $CO_2$ begins in 2020; and 3) a $CO_2$ mass emissions cap scenario, where $CO_2$ emissions are limited to 29.4 million tons per year beginning in 2020. The results of the analysis for the Base load scenarios are summarized in Table 8.(4)-3.

**Table 8.(4)-3**
**Optimal Expansion Plans (Base Load Scenarios)[5]**

| $CO_2$ | 0C | 0C | 0C | MC | MC | MC | Cap | Cap | Cap |
|---|---|---|---|---|---|---|---|---|---|
| Load | BL | BL | BL | BL | BL | BL | BL | BL | BL |
| Gas Price | LG | MG | HG | LG | MG | HG | LG | MG | HG |
| 2014 | | | | | | | | | |
| 2015 | CR7 | CR7 | CR7 | CR7 | CR7 | CR7 | CR7 | CR7 | CR7 |
| 2016 | BRS | BRS | BRS | BRS | BRS | BRS | BRS | BRS | BRS |
| 2017 | | | | | | | | | |
| 2018 | GR5 | GR5 | GR5 | GR5 | GR5 | GR5 | GR5 | GR5 | GR5 |
| 2019 | | | | | | | | | |
| 2020 | | | | Ret BR1-2<br>1x1G(1) | Ret BR1-2<br>1x1G(1) | Ret BR1-2<br>2x1G(1) | Ret BR1-2<br>2x1G(1) | Ret BR1-2<br>2x1G(1) | Ret BR1-2<br>2x1G(1) |
| 2021 | | | | | | | | | |
| 2022 | | | | 2x1G(1) | 2x1G(1) | | | | |
| 2023 | | | | | | | | | |
| 2024 | | | | | | | | | |
| 2025 | 2x1G(1) | SCCT(1) | 2x1G(1) | | | | | | |
| 2026 | | | | | | | | | |
| 2027 | | SCCT(1) | | | | | | | |
| 2028 | | | | | | | | | Wind(4) |

$CO_2$: Zero (0C), Mid (MC), Mass Emissions Cap (Cap) Gas Price: Low (LG), Mid (MG), High (HG) Load: Base (BL)

[5] In Table 8.(4)-3, the value in parentheses following the technology option's reference name indicates the number of units added in a given year.

In the Zero $CO_2$ price scenarios, the addition of new capacity (in 2025) coincides with the Companies need for capacity, as expected. In the Mid $CO_2$ price and $CO_2$ mass emissions cap scenarios, new capacity is added in 2020. Two factors drive this result. First, the system benefits from low $CO_2$-emitting generation in a carbon-constrained world, even when the capacity and energy may not be needed to maintain the target reserve margin; the production cost savings associated with low $CO_2$-emitting generation more than offsets the increased cost of building new generation sooner. Second, in these scenarios, average capacity factors of Brown 1 and 2 were consistently less than 10 percent; therefore, these two units were assumed to be retired in 2020 in these scenarios.

Because NGCC capacity is added first in eight of the nine scenarios in Table 8.(4)-3, a natural gas unit will likely be included in the Companies' least cost plan to meet load requirements beyond 2018. In the Zero $CO_2$ price scenarios, NGCC capacity is added to meet customers' growing need for energy (as well as capacity). In the Mid $CO_2$ price and $CO_2$ mass emissions cap scenarios, NGCC capacity is added to meet the need for low-emitting $CO_2$ resources (as well as customers' energy needs). Generally speaking, more NGCC capacity is added sooner in the $CO_2$ mass emissions cap scenarios compared to the Mid $CO_2$ price scenarios. Without this additional NGCC capacity, the system cannot economically meet the $CO_2$ mass emissions cap.

In the High gas, $CO_2$ emissions cap scenario, wind capacity is added to the Companies' portfolio in 2028. In the High gas price scenario, gas prices exceed $8/mmBtu beyond 2025. High gas prices coupled with the $CO_2$ mass emissions cap makes wind generation competitive in this scenario.

A complete discussion of the Companies' resource assessment is included in Volume III, Technical Appendix (see report titled *2014 Resource Assessment*).

## 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. The information in these tables is based on the Companies' Base load forecast.

**Table 8.(4)(a)-1**
**Kentucky Utilities Company / Louisville Gas and Electric Company**
**Resource Assessment and Acquisition Plan**
**Resource Capacity Available (MW)**
**At Summer Peak**

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Forecasted Peak Load** | | 7,278 | 7,364 | 7,450 | 7,536 | 7,623 | 7,663 | 7,721 | 7,780 | 7,839 | 7,893 | 7,948 | 8,003 | 8,059 | 8,115 | 8,171 |
| **Peak Reductions** | | | | | | | | | | | | | | | | |
| **Existing DSM** | | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 |
| **Cumulative Incremental DSM** | | 30 | 60 | 90 | 119 | 148 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 |
| **Total Demand** | 6,434 | 6,972 | 7,028 | 7,085 | 7,142 | 7,199 | 7,257 | 7,315 | 7,374 | 7,433 | 7,488 | 7,542 | 7,598 | 7,653 | 7,709 | 7,766 |
| | | | | | | | | | | | | | | | | |
| **Capacity From:** | | | | | | | | | | | | | | | | |
| **Existing Resources** | 7,918 | 7,904 | 7,876 | 7,859 | 7,859 | 7,859 | 7,859 | 7,859 | 7,859 | 7,859 | 7,859 | 7,859 | 7,859 | 7,859 | 7,859 | 7,859 |
| **Planned Resources** | 0 | 0 | 640 | 649 | 649 | 1,319 | 1,319 | 1,319 | 1,319 | 1,319 | 1,319 | 1,319 | 1,520 | 1,520 | 1,721 | 1,721 |
| **Firm Purchase (OVEC)** | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 |
| **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 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 | 724 |
| **Curtailable Customers** | 0 | 128 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 |
| **Total Supply*** | 8,073 | 8,187 | 8,078 | 8,070 | 8,070 | 8,740 | 8,740 | 8,740 | 8,740 | 8,740 | 8,740 | 8,740 | 8,941 | 8,941 | 9,142 | 9,142 |
| | | | | | | | | | | | | | | | | |
| **16% Reserve Requirements** | 1,029 | 1,116 | 1,125 | 1,134 | 1,143 | 1,152 | 1,161 | 1,170 | 1,180 | 1,189 | 1,198 | 1,207 | 1,216 | 1,225 | 1,233 | 1,243 |
| **Excess (Deficit)** | 610 | 99 | -75 | -149 | -215 | 389 | 322 | 254 | 186 | 118 | 54 | -9 | 128 | 63 | 199 | 133 |
| **Reserve Margin (%)** | 25.5% | 17.4% | 14.9% | 13.9% | 13.0% | 21.4% | 20.4% | 19.5% | 18.5% | 17.6% | 16.7% | 15.9% | 17.7% | 16.8% | 18.6% | 17.7% |

* Table 8.(4)(a)-1 excludes any capacity additions for 2015 through 2017 as these additions have not been identified.

Note: In the peak demand forecast, DSM is applied using a mid-year methodology rather than a calendar-year methodology.

Note: 2013 peak load is from actual peak on 9/10/2013

## Table 8.(4)(a)-2
## Kentucky Utilities Company / Louisville Gas and Electric Company
## Resource Assessment and Acquisition Plan
## Resource Capacity Available (MW)
## At Winter Peak

| | 2013/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Forecasted Peak Load** | | 6,176 | 6,266 | 6,307 | 6,356 | 6,429 | 6,449 | 6,532 | 6,551 | 6,583 | 6,612 | 6,650 | 6,708 | 6,779 | 6,809 | 6,825 |
| **Peak Reductions** | | | | | | | | | | | | | | | | |
| **Existing DSM** | | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 |
| **Cumulative Incremental DSM** | | 13 | 33 | 54 | 74 | 95 | 72 | 72 | 72 | 72 | 72 | 72 | 72 | 72 | 72 | 72 |
| **Total Demand** | 7,114 | 6,022 | 6,091 | 6,112 | 6,141 | 6,193 | 6,235 | 6,318 | 6,337 | 6,369 | 6,398 | 6,436 | 6,494 | 6,565 | 6,595 | 6,612 |
| | | | | | | | | | | | | | | | | |
| **Capacity From:** | | | | | | | | | | | | | | | | |
| **Existing Resources** | 7,977 | 7,941 | 7,912 | 7,906 | 7,906 | 7,906 | 7,906 | 7,906 | 7,906 | 7,906 | 7,906 | 7,906 | 7,906 | 7,906 | 7,906 | 7,906 |
| **Planned Resources** | 0 | 0 | 657 | 657 | 657 | 1,314 | 1,314 | 1,314 | 1,314 | 1,314 | 1,314 | 1,314 | 1,534 | 1,534 | 1,754 | 1,754 |
| **Firm Purchase (OVEC)** | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 |
| **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 | 732 | 732 | 732 | 732 | 732 | 732 | 732 | 732 | 732 | 732 | 732 | 732 | 732 | 732 |
| **Curtailable Customers** | 0 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 | 131 |
| **Total Supply*** | 8,138 | 8,233 | 8,129 | 8,123 | 8,123 | 8,780 | 8,780 | 8,780 | 8,780 | 8,780 | 8,780 | 8,780 | 9,000 | 9,000 | 9,220 | 9,220 |
| | | | | | | | | | | | | | | | | |
| **16% Reserve Requirements** | 1,138 | 1,116 | 1,125 | 1,134 | 1,143 | 1,152 | 1,161 | 1,170 | 1,180 | 1,189 | 1,198 | 1,207 | 1,216 | 1,225 | 1,233 | 1,243 |
| **Excess (Deficit)** | -114 | 1,096 | 913 | 878 | 839 | 1,435 | 1,384 | 1,292 | 1,263 | 1,221 | 1,184 | 1,137 | 1,290 | 1,210 | 1,391 | 1,365 |
| **Reserve Margin (%)** | 14.4% | 36.7% | 33.5% | 32.9% | 32.3% | 41.8% | 40.8% | 39.0% | 38.6% | 37.9% | 37.2% | 36.4% | 38.6% | 37.1% | 39.8% | 39.4% |

* Table 8.(4)(a)-2 excludes any capacity additions for 2015 through 2017 as these additions have not been identified.

Note: In the peak demand forecast, DSM is applied using a mid-year methodology rather than a calendar-year methodology.

Note: 2013/14 winter peak load is from actual peak on 1/6/2014

## 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;**

The Companies developed optimal expansion plans over multiple natural gas price, load, and $CO_2$ scenarios. For each of the scenarios evaluated, the requested information is summarized in *Appendix to Sections 8 and 9 – Scenario Data* (see Volume III, Technical Appendix).

**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.**

The Companies developed optimal expansion plans over multiple natural gas price, load, and $CO_2$ scenarios. For each of the scenarios evaluated, the requested information is summarized in *Appendix to Sections 8 and 9 – Scenario Data* (see Volume III, Technical Appendix).

**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;**

**Resource Assessment**

Both the economics and practicality of supply-side options are carefully examined to develop an IRP for reliably meeting future energy requirements at the lowest reasonable cost. The Companies' Resource Assessment was completed in two parts. First, the Companies performed a screening analysis of more than 50 generation technology options to determine a subset of the most competitive options. Then, this subset of generation technology options was incorporated into a detailed expansion planning analysis to determine the optimal expansion plans beyond 2018.

In the screening analysis, the levelized cost of the technology options was calculated at various levels of utilization. In addition to the level of utilization (i.e., capacity factor), the levelized cost of each technology option is impacted by the uncertainty in capital cost, fuel cost, unit efficiency, and $CO_2$ emissions. As a result, the technology options were evaluated over three capital cost scenarios, three heat rate scenarios, three fuel scenarios, two $CO_2$ scenarios, and ten capacity factors for a total of 540 cases. Given the uncertainty in REC prices and the availability of investment tax credits ("ITC") for renewable technologies, two iterations of 540 cases were evaluated:

- No ITC or RECs: This iteration did not include an ITC for renewable technologies or wind and solar RECs.
- 10% ITC and RECs: This iteration incorporated a 10% ITC and current REC market prices for solar and wind technologies.

The Companies continue to use the Strategist® program for their detailed expansion planning analyses. Strategist® is a proprietary computer model developed by Ventyx, which integrates the supply-side and demand-side inputs to produce a ranked number of plans that meet the prescribed environmental compliance and reliability criteria. The detailed expansion planning analysis assumed that existing units would remain economic to operate provided their capacity factors do not consistently fall below 10%. A complete summary of the models and methodologies utilized in the resource assessment is included in the report titled *2014 Resource Assessment* contained in Volume III, Technical Appendix.

The list of generation technology types considered in the resource assessment includes natural gas, coal-fired, waste to energy, energy storage, renewable, and nuclear technologies. The cost and performance characteristics of these technology options were estimated by Burns & McDonnell, an engineering consulting firm. More information regarding these technology options is contained in the report titled *2014 Resource Assessment* contained in Volume III, Technical Appendix.

**Demand Side Management Resource Screening and Assessment**

To help understand where the potential for energy efficiency programming is within the Companies service territory, a market potential study ("Study") was conducted by The Cadmus Group.[6] The assessment quantified the amount of energy and demand that could be saved in the Companies service territory from 2014 to 2033. The Study focused primarily on efficient technologies and practices widely commercially available at the time of the assessment, while

[6] The Companies submitted a Certificate of Public Convenience and Necessity ("CPCN") in Case No. 2011-00375. As a result of this case, the KPSC requested that the Companies explore the potential of energy efficiency in Kentucky. (Order May 3, 2012, Paragraph 5).

accounting for known changes in codes and standards; technical limitations; total resource cost effectiveness and customer willingness to adopt, to assure that savings targets can be achieved.

The proposed 2015-2018 Program Portfolio is supported not only by the aforementioned Study, but also a separate DSM Program Review conducted by The Cadmus Group and supported through collaboration with the Companies' DSM Advisory Group. Cadmus Group was hired by the Companies to review the 2012-2018 DSM/EE Program Plan. This review was made in conjunction with the Commission's mandated Study. The DSM Program Review included, but was not limited to, a review of existing programming, a gap analysis, and recommendations for future programming. The intent of the DSM Program Review was to provide options for consideration to improve program efficiency, support expansion or capture higher energy savings. Many of the recommendations presented in the DSM Program Review have been incorporated in Companies latest DSM filing, Case No. 2014-00003.

In addition to third party support of The Cadmus Group, the Companies DSM Advisory Group was also utilized to understand the proposed programs from a customer perspective. The DSM Advisory Group, formed in 2000, provides an opportunity for representatives from each of the Companies customer segments to discuss and provide feedback on the DSM / EE programs provided through the energy efficiency portfolio. Constituents who attend these meetings not only have an opportunity to discuss available and potential programming in a venue that supports active two way communication, but are also provided educational opportunity in various areas of program cost effectiveness determination, DSM regulatory approval processes and the Companies efforts to coordinate programming with other organizations for maximized participation and customer benefit.

The Companies held a meeting with the Group in December 2012 to discuss the energy efficiency market potential study and the efforts that were beginning to develop internally related to the current DSM / EE portfolio. The second scheduled meeting with the Group took place in June 2013 for additional feedback. The Group received information regarding historical program financial and energy/demand performance; additional information regarding expiring DSM/EE programming; scope of the energy efficiency potential study being conducted by The Cadmus Group; potential program modification opportunities as well as timing of future meetings. The third scheduled meeting with the Group took place in October 2013. The Group reviewed energy efficiency programming history to date; preliminary results from the energy efficiency potential study conducted by The Cadmus Group; programs expiring from the portfolio as well as the Companies DSM/EE plans for 2015-2018.

The Companies developed the current DSM/EE Plan in collaboration with their Energy Efficiency Advisory Group that sought opportunities for DSM programs for both the residential and commercial customer segment. The currently approved DSM/EE plan in Case No. 2011-00134 further increased program participation opportunities for customers and supports the Companies in meeting their IRP cumulative demand reduction.

The Companies are seeking approval for enhancements to programming in their currently approved portfolio from Case No. 2011-00134 and the continuation of one program in approved Case No. 2007-00319. The proposed enhancements of programming take into account aspects of certain programming that is set to expire December 31, 2014 in Case No. 2007-00319. The proposal in front of the Commission will allow the Companies to align their DSM/EE portfolio with all approved programs ending in 2018. This methodology will allow the Companies an opportunity to review their portfolio holistically in conjunction with a market place perspective as well as the utility cost perspective, thus allowing the Companies to evaluate additional programming with potential new energy efficiency technologies as they become economically viable.

On the basis of the above-described analyses and collaboration, the Companies propose to enhance and extend through December 31, 2018 the following existing DSM/EE programs: Commercial Load Management/ Demand Conservation Program; Residential Incentives Program; Commercial Conservation / Commercial Incentive Program; and the Residential Conservation / Home Energy Performance Program.

In addition to the programs listed above, the following programs will remain within their current designs as approved in Case No. 2011-00134 through 2018: Smart Energy Profile Program; Residential Load Management / Demand Conservation Program; Residential Refrigerator Removal Program; Residential Low Income Weatherization Program (WeCare), and Program Development and Administration.

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

The Companies' resource planning process is based on numerous assumptions. Key assumptions are discussed in the following sections.

### Fuel Price Forecast

The Companies' fuel price forecasts are updated annually as part of the Companies' planning cycle. The first five years of the Companies' current coal price forecast is a combination of the price forecast for coal already under contract and open position price curves which are developed from current market offers solicited by the Company in the spring and Wood Mackenzie's Spring 2013 Long Term Coal Outlook through 2018. Thereafter, coal prices reflect the growth rates in EIA's Annual Energy Outlook 2013 Reference Case 'Coal-Minemouth' price forecast. An average transportation cost adder is escalated throughout the forecast period.

Natural gas prices through 2033 are forecasted by the EIA as shown in their 2013 AEO.[7] Beyond 2033, the prices are extrapolated based on the rate of escalation prior to 2033.[8] For purposes of this study, the three natural gas price scenarios were assumed to be equally likely. A pipeline basis and pipeline transportation estimate for deliveries to the Companies' plant sites is added to derive a delivered LG&E-KU natural gas price forecast.

Fuel oil prices are projected using the NYMEX New York Harbor #2 fuel oil price futures contract at the time the Companies' forecast is developed each year, and extended for the remainder of the forecast using the historic relationship of the prices for #2 fuel oil and WTI oil and a forecast of WTI oil prices taken from IHS Global Insight's 30-year macro forecast from the Spring of 2013. The historical ratio of the LG&E-KU fuel purchase price to the #2 fuel oil price is used to escalate the #2 fuel oil price forecast to a delivered LG&E-KU fuel oil price forecast.

The fuel price forecasts significantly influence the Companies' IRP by affecting the selection of an optimal technology type. The Companies develop 30-year base fuel price 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 for the screened

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[7] The "Mid," "High," and "Low" case natural gas price forecasts are based on EIA's AEO 2013 "Reference," "Low Oil and Gas Resource," and "High Oil and Gas Resource" cases, respectively. For the EIA's AEO 2013 data tables, see http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=3-AEO2013&table=13-AEO2013&region=0-0&cases=ref2013-d102312a.

[8] The "Mid," "High," and "Low" case natural gas price forecasts are escalated at the 2023-2033 compound annual growth rates of 4.0 percent, 4.3 percent, and 4.0 percent, respectively.

technology options. Representative fuel costs for each technology screened are obtained from the base and sensitivity fuel price forecasts. Fuel price sensitivities factored into the resource assessment are discussed in the report titled *2014 Resource Assessment* contained in Volume III, Technical Appendix.

**New Unit Capital Costs**

The uncertainty in capital cost for a given generation technology option is a function of the technology option's maturity and the extent to which the cost of building a technology option is site-dependent. Generally, the more conventional or commercially mature technology options have a narrower capital cost range, whereas the more developmental or site-dependent technology options have a wider range. The screening analysis considered a range of capital cost estimates for each technology option. These ranges are discussed in the report titled *2014 Resource Assessment* contained in Volume III, Technical Appendix.

**Clean Air Act Compliance Plan**

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

***Oxides of Nitrogen ($NO_X$)***

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

Completion and operation of the Companies' first SCR installation on existing units occurred in 2002, and the most recent SCR installation on an existing unit came on-line in December 2012. SCR are installed on eight of the Companies' baseload generating units (Trimble County Units 1 and 2; Mill Creek Units 3 and 4; and Ghent Units 1, 3, and 4; and E.W. Brown Unit 3).

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

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 began in 2009. However, CAIR was remanded back to EPA for further consideration. This meant that CAIR would remain in effect until modifications or new rules were promulgated. Compliance under CAIR's annual and ozone season $NO_X$ reduction programs has required year-round operation of the SCR currently installed at the Companies' facilities to meet lower $NO_X$ emission caps.

The original proposed efforts by EPA to replace CAIR were referred to as the Clean Air Transport Rule ("CATR"). On August 6, 2011, the EPA published in the federal register the final version under the title of Cross-State Air Pollution Rule ("CSAPR"). The CSAPR included limitations on interstate trading and prescribed a new trading program for $SO_2$ allowances that did not allow for previously banked allowances to be used. The reductions prescribed by the CSAPR were similar to the CAIR reductions for the Companies. In comparison to CAIR, the CSAPR included a two-phase program for $NO_X$ with less reduction required by the Companies in Phase I by 2012 and somewhat less reduction required for Phase II in 2014 and beyond.

Due to subsequent petitions against the CSAPR, primarily concerning issues with EPA methodology of allocations for alleviating States contributions downwind Ozone and $PM_{2.5}$ issues, the CSAPR was stayed by the D.C. Circuit court in December of 2011. On August 12, 2012 the D.C. Court of Appeals vacated the CSAPR, remanded it to EPA for rewriting, and ordered EPA to continue to administer the CAIR rule until the rewrite is complete and promulgated.

The EPA and a number of environmental groups, states, and others petitioned the D.C. Circuit Court of Appeals for a full court re-hearing of the CSAPR. The petition was denied on

August 12, 2012. A similar appeal was then filed with the Supreme Court. In June of 2013, the Supreme Court agreed to rehear arguments to re-instate the CSAPR. The initial arguments were heard in December of 2013 with a final decision expected in the Spring of 2014. The CAIR rule will continue to be implemented until a decision by the Supreme Court directs otherwise or a separate action by EPA to address transport of emissions affecting downstream the national ambient air quality standards ("NAAQS") attainment is promulgated.

***Sulfur Dioxide***

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

The Companies have used these accrued allowances since 2000 to offset $SO_2$ emissions in excess of the annual limitation. Additionally, the Companies have increased the removal efficiencies of existing FGD units to conserve these emission allowances. If these emission allowances are depleted, the Companies will purchase allowances from the market or explore other alternatives to further reduce $SO_2$ emissions.

Additionally, the Acid Rain Program was supplemented in 2010 by the $SO_2$ program of the CAIR. CAIR's $SO_2$ program targeted reductions of the Companies allowable $SO_2$ emissions by around 50 percent in 2010 and was aiming at a 65 percent reduction in 2015. As a result of the Acid Rain Program and CAIR, the Companies began construction of a number of projects to reduce fleet-wide $SO_2$ emissions, including the installation of FGDs on Ghent Units 2[9], 3 and 4 and E.W. Brown Units 1, 2, and 3. Installation of these FGDs was completed between May 2007 and June 2010.

There are many different designs of FGD equipment. The new equipment installed for Ghent and E.W. Brown units are wet limestone, forced-oxidation systems, similar to FGD equipment already in use at the Ghent, Trimble County, and Mill Creek Stations. These types of systems are among the highest in $SO_2$ capture efficiency. This system crushes and slurries the limestone material into liquid form and introduces it into the flue gas stream, typically by spraying. 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, the gypsum may be used for beneficial re-use projects (e.g., used by wallboard makers, used as structural fill material, etc.).

As mentioned previously, the CAIR Rule was replaced with the CSAPR and subsequently re-established when the CSAPR was remanded. The CAIR $SO_2$ program began in 2010 and included a Phase II beginning in 2015 to further reduce $SO_2$ allowances and associated emissions.

The original proposed efforts by EPA to replace CAIR were referred to as the CATR. On August 6, 2011, the EPA published in the federal register the final version under the title of CSAPR. The reductions prescribed by the CSAPR were similar for the Companies as CAIR

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

reductions. Under CSAPR, less reduction of $SO_2$ was required during 2012-2013, but more reduction was required for 2014 and beyond. It included limitations on interstate trading and prescribed a new trading program for $SO_2$ allowances that did not allow for previously banked allowances to be used.

The CSAPR was subsequently remanded (see $NO_X$ above) and the CAIR rule will continue to be implemented until a decision by the Supreme Court directs otherwise or a separate action by EPA to address transport of emissions affecting downstream NAAQS attainment is promulgated.

***Hazardous Air Pollutants***

On May 18, 2005, EPA delisted electric generating units from the list of sources subject to hazardous air pollutant controls under Section 112(c) of the Clean Air Act and promulgated the Clean Air Mercury Rule ("CAMR") which would have established a two phase "cap and trade" program for reduction of mercury emissions from those units.

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

Register on February 16, 2012 that set emission limits for mercury, acid gases, toxic metals, and organics including dioxins and furans based on the MACT for the industry applicable to coal-fired and oil-fired units. The compliance date is April 16, 2015; however, the rule allows the permitting authority to grant up to one year extension based on submittal of a justifiable request.

To meet emissions compliance limitations with the MATS rule, the Companies' are in the process of installing pulse jet fabric filter systems ("PJFF") on all coal fired units with the exception of Trimble County Unit 2 and Brown Units 1 and 2. The Trimble County Unit 2 currently includes a PJFF as original equipment and Brown Units 1 and 2 will utilize additives to assist with Mercury removal and average their emissions with the emissions of Unit 3 in a common stack. Dry sorbent injection systems will be installed on each unit that receives a PJFF system for the purpose of protecting the materials of construction. Powdered activated carbon injection systems will be added to enhance removal of mercury emissions. Emissions of mercury and acid gases will be further reduced at all coal fired units with the existing wet flue gas desulfurization (WFGD) systems and with new WFGD systems at Mill Creek.

**Unit Availability**

The Companies' existing resources include both company-owned generating units and purchase power agreements with OVEC. The availability of these resources has a significant impact on the Companies' target reserve margin and a smaller impact on the Companies' resource assessment. The unit availability assumptions used in the Companies' resource assessment are discussed in the report titled *2014 Resource Assessment* contained in Volume III, Technical Appendix. The same unit availability assumptions were used for existing and planned resources in the Companies reserve margin study (see *2014 Reserve Margin Study* in Volume III, Technical Appendix).

**Regulation of Greenhouse Gas Emissions**

In addition to the actions already mentioned regarding the Clean Air Act, Congress has considered legislation to control emissions of greenhouse gases and/or $CO_2$ as well as prohibit the EPA from regulating $CO_2$ via the Clean Air Act. In this uncertain legislative environment, the EPA has proceeded down the path of issuing regulations (on September 22, 2009) for the reporting of GHG emissions from large sources (facilities with more than 25,000 metric tons of carbon dioxide equivalent emissions or a maximum rate heat input capacity of more than 30 MMBtu/hour). Annual reporting to EPA for some sources began March 31, 2011.

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

In December 2010, EPA also announced a plan to propose NSPS regulations for GHG emissions from the electric utility industry by July 26, 2011, with potential finalization to occur in May 2012. The EPA did not meet this planned proposal date. However, on June 25, 2013, President Obama announced his "Climate Action Plan", which laid out a timeline and targets for regulatory development to reduce GHG emissions. President Obama's Climate Action Plan targeted 17 percent reductions from 2005 emissions by 2020. In response, EPA issued a proposed NSPS for GHG emitted from new fossil fuel fired electric generation sources. The proposal, published in the Federal Register on January 8, 2014, establishes the effective date of applicability for the specific standards limiting $CO_2$ emissions from new fossil fuel fired electric generating facilities, including coal fired, natural gas fired (if greater than 1/3 of the maximum potential generation is used on the grid), and integrated gasification combined cycle ("IGCC") units. Additionally, EPA targeted to propose regulations for GHG NSPS applicable to existing fossil fuel fired electric generating units by June 2014.

**316 (b) – Regulation of cooling water intake structures**

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

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

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

EPA anticipates finalizing a new rule in May 2014, but that timing may be extended to 2015. The Companies expect both industry and environmental groups will utilize the court system to again challenge the new rule and possibly delay implementation deadlines. The regulations will address both impingement and entrainment issues, thus affecting the Companies' facilities, including those already equipped with closed cycle cooling (cooling towers). Possible requirements within the rule could include: cooling towers on all active units, "helper" towers on once-thru cooling units for use during spawning season and low flow periods, fine mesh screens (1-2 mm) for water intake, fish return systems associated with the screens, and/or annual in-stream fish studies. These potential capital investments could be required within the time period of this IRP document. The Companies will continue to review this issue.

**Aging Generating Units**

The two oldest steam generating units in the system are Brown Units 1 and 2, each over 50 years old. Some of the oldest combustion turbines are the smaller LG&E combustion turbines and the KU Haefling combustion turbines ("CTs"). Each of these units is over 30 years of age, which is considered the typical design life for small frame combustion turbines. Table 8.5(b)-2 lists the ages of the oldest units.

**Table 8.5(b)-2**
**Aging Units**

| Fuel | Plant Name | Unit | Summer Net Capacity | In Service Year | Age (2014) |
|---|---|---|---|---|---|
| Coal | Brown | 1 | 106 | 1957 | 57 |
| Coal | Brown | 2 | 166 | 1963 | 51 |
| Gas | Cane Run | 11 | 14 | 1968 | 46 |
| Gas | Paddy's Run | 11 | 12 | 1968 | 46 |
| Gas | Paddy's Run | 12 | 23 | 1968 | 46 |
| Gas | Zorn | 1 | 14 | 1969 | 45 |
| Gas | Haefling | 1,2 | 28 | 1970 | 44 |

The Companies periodically perform high-level condition and performance assessments on their generating units. Additionally, the Black and Veatch performed a remaining life assessment on Brown 1 and 2 in 2012. The assessment concluded that these units could operate reliably for the foreseeable future provided that the units continued to be appropriately operated and maintained.

The economics surrounding the continued operation of the Companies' older units will continue to be periodically reviewed to ensure the efficiency of the overall system. More stringent environmental regulations could result in the retirement of these units even without a significant mechanical failure.

**Key Uncertainties**

The Companies evaluate long-term resource decisions under a number of possible futures to ensure that customers' energy needs are reliably met at the lowest reasonable cost. While there are a number of uncertainties that could have some impact on the Companies' resource decisions, the uncertainties in native load (demand and energy), natural gas prices, and GHG regulations are the most important to consider when evaluating long-term generating resources. Each of these uncertainties is discussed in the subsections that follow.

**Native Load Requirements**

The only reason for the Companies to acquire new supply-side or demand-side resources is to reliably meet customers' future energy needs at the lowest reasonable cost. Therefore, the forecast of customers' future demand and energy needs has a significant impact on the Companies' optimal expansion plan. The volume of future load (demand and energy) is driven by future economic activity, the adoption rate of new and existing DSM programs, and the development of new electric end-uses (e.g., consumer electronics, electric vehicles, etc.). The Companies utilize the best information available to develop a reasonable long-term load forecast. As with any long-term forecast, the uncertainty associated with it tends to grow through time. Therefore, "High" and "Low" load forecasts were also developed which reflect the statistical uncertainty about the base load forecast. The load forecasts considered in the resource assessment are discussed in Section 5 Table 5.(6)-1 and Table 5.(6)-2.

**Natural Gas Prices**

Because of the EPA's proposed NSPS for GHG, natural gas has become the fuel of choice for new fossil generation. An abundance of natural gas supply resulting from advancements in natural gas drilling technologies has put downward pressure on prices and greatly improved the economics of NGCC technology. On the other hand, the impending nationwide retirement of coal units and the shift to NGCC units will increase the demand for natural gas and put upward pressure on prices. Additional upside price risk is associated with the possibility of regulations limiting the extraction of shale gas. The price of natural gas could have a significant impact on the Companies' optimal expansion plan; lower natural gas prices would favor natural gas technology options, while higher natural gas prices would make renewable generation more competitive. To address this long-term natural gas price uncertainty, the resource assessment considered three natural gas price scenarios. The "Low," "Mid," and "High" scenarios are discussed in detail in the Companies' *2014 Resource Assessment* contained in Volume III, Technical Appendix.

**Greenhouse Gas Scenarios**

Expectations for action on climate change are rising, including more stringent regulations for new and existing generating units. GHG regulation could have a significant impact on the Companies' optimal expansion plan by making renewable generation more competitive and potentially resulting in the economic retirement of existing units, which would accelerate the need for additional generating resources. Because the exact nature of future GHG regulations, should they occur, remains unknown, the Companies utilized two approaches in the expansion planning analysis to evaluate their potential impact. The first approach puts a price on each ton of $CO_2$ emitted; the second places a cap on $CO_2$ mass emissions.

The analysis considered "Mid" and "Zero" $CO_2$ price scenarios. The Mid $CO_2$ price scenario was prepared by Synapse Energy Economics, Inc., a consulting firm that does a significant amount of work for various environmental groups such as the Sierra Club and Natural Resources Defense Council. In the Mid $CO_2$ price scenario, $CO_2$ prices begin in 2020. Because future GHG regulations on existing units is by no means assured, a Zero $CO_2$ price scenario was analyzed assuming that there is never a price on future $CO_2$ emissions.

The second approach for evaluating the potential impact of GHG regulations places a cap on annual $CO_2$ mass emissions. In June 2013, the President released his Climate Action Plan which includes his intention to reduce $CO_2$ emissions from 2005 levels by 17 percent. For this reason, in the "$CO_2$ mass emissions cap" scenario, annual $CO_2$ mass emissions for the Companies are limited to 29.4 million tons of $CO_2$ per year beginning in 2020. The Companies' *2014 Resource Assessment* discusses each of the $CO_2$ scenarios considered in detail.

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

**Demand-side Management Screening**

The benefit/cost calculations for the program plan were performed using DSMore, a PC-based software package developed by Integral Analytics, Inc. DSMore provides more robust analytics surrounding weather and market conditions and a more transparent platform to understand the underlying calculations associated with the benefit/cost tests. The Companies calculated the four benefit/cost tests contained in the California Standard Practice Manual:

Economic Analysis of Demand-Side Programs and Projects ("Manual").[10] These tests and their Manual definitions are:

- **The Participant Test:** The Participant Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.[11]
- **The Ratepayer Impact Measurement Test:** The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation is less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.[12]
- **The Total Resource Cost Test:** The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change

[10] The Manual is available online at: http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

[11] Manual at 8.

[12] Manual at 13.

and the incentive terms intuitively cancel (except for the differences in net and gross savings).[13]

- **The Program Administrator Cost Test (or "Utility Cost Test"):** The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC [Total Resource Cost] benefits. Costs are defined more narrowly.[14]

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

**Table 8.(5)(c)-1**

| | DSMore Scoring | | | |
|---|---|---|---|---|
| **Program** | Participant Test | Utility Cost Test | Ratepayer Impact Test | Total Resource Cost Test |
| Residential Low Income Weatherization (WeCare) | N/A | 2.57 | 0.60 | 2.57 |
| Residential Load Management | N/A | 1.47 | 1.02 | 2.95 |
| Residential Refrigerator Removal | N/A | 1.86 | 0.56 | 2.26 |
| Smart Energy Profile | N/A | 3.07 | 0.74 | 3.07 |
| Program Development & Administration | N/A | 0.00 | 0.00 | 0.00 |
| | | | | |
| Residential Conservation | 6.50 | 2.52 | 0.68 | 1.93 |
| Residential Incentives | 3.20 | 4.53 | 0.81 | 2.37 |
| Commercial Conservation | 7.56 | 16.42 | 1.18 | 7.26 |
| Commerical Load Management | N/A | 1.64 | 0.86 | 2.27 |
| Customer Education & Public Information | N/A | 0.00 | 0.00 | 0.00 |
| **Overall Portfolio** | **8.66** | **3.13** | **0.86** | **3.07** |

As demonstrated, all of the proposed programs with enhancements have a Participant Test and Total Resource Cost Test above the passing score of 1.0.

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[13] Manual at 18.

[14] Manual at 23.

**Supply-Side Screening Assessment**

In the screening analysis, the Companies computed the 30-year levelized cost (in $/MWh) over a range of scenarios for the technology options considered. The levelized cost includes the costs associated with building and operating the unit.

With some exceptions, the levelized cost of each technology option was calculated over three capital cost scenarios, three heat rate scenarios, three fuel scenarios, two $CO_2$ scenarios, and ten capacity factors for a total of 540 cases. Technology options ranked among the top four least-cost technology options in any case were considered for the more detailed expansion planning analysis.

Several technology options were limited to a maximum capacity factor based on the operating characteristics of the technology option. Capacity factors for wind and solar were limited to 27 percent and 17 percent, respectively. The hydroelectric option was limited to a 40 percent capacity factor based on the Companies' experience with their current hydro assets.

Some technology options were not considered in the screening analysis. The 3x1 NGCC technology options were excluded from the analysis due to their size; it is difficult for the Companies to recover from the loss of such a large unit given the relatively small size of their generating portfolio. The "J-Class" combustion turbine was also excluded from the analysis due to its nascent design and limited operating history. Although it is now commercially available in the United States, no orders have been placed to date. The small modular nuclear reactor was not included as well due to significant challenges in siting and permitting the unit especially in Kentucky.[15]

[15] Since 1984, the Kentucky General Assembly has had a moratorium on any nuclear plant construction without a plan for permanent waste disposal.

Given the uncertainty in REC prices and the availability of investment tax credits ("ITC") for renewable technologies, two iterations of 540 cases each were evaluated:

- No ITC or RECs: This iteration did not include an ITC for renewable technologies or wind and solar RECs.
- 10% ITC and RECs: This iteration incorporated a 10% ITC and current REC market prices for solar and wind technologies.

**Expansion Planning Analysis**

The Strategist computer model was used to develop optimal expansion plans for each of the scenarios considered. Strategist uses the Companies' peak and energy load forecasts and load shapes for multiple years to create typical monthly load shapes for production costing purposes. System dispatch and operation are simulated using a load duration curve production costing technique. Production costs including fuel, incremental O&M, purchase power, and emission costs are calculated based on inputs including generating unit and purchase power characteristics, fuel costs, and unit or fuel specific emissions information. All combinations of potential options are evaluated to produce a list of resource plans, subject to user specified constraints, that satisfy the Companies' minimum reserve margin criterion. The production cost analysis is combined with an analysis of new construction expenditures to suggest an optimal resource plan and sub-optimal resource plans based on minimizing utility cost.

Typically, the Companies configure Strategist to only evaluate new units that are needed to maintain the target reserve margin. However, when burdened by $CO_2$ regulations, the system may benefit from additional low or zero $CO_2$-emitting resources before it is necessary to add capacity to maintain the reserve margin target. For this reason, 2x1 NGCC and wind units were evaluated in the Mid $CO_2$ price scenarios before the capacity was needed to maintain the target reserve margin.[16]

Capacity factors for existing coal units were averaged over the three gas price scenarios in each load-$CO_2$ price scenario. If an existing coal unit's capacity factor was consistently less than 10 percent in a given load-$CO_2$ price scenario, the unit was assumed to be retired in the year when its capacity factor consistently dropped below 10 percent.

### 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;

The reliable supply of electricity is vital to Kentucky's economy and public safety. As electricity has become a more integral part of daily routines, customers have grown to expect it to be available at all times and in all weather conditions. The Companies carry generating reserves in excess of their expected peak demand in an effort to meet the needs of their customers and the communities they serve. However, customers also demand that energy is affordable, thus the Companies must balance the costs of generating capacity with the reliability benefits provided by that capacity.

The Companies' reserve margin analysis was prepared to determine the Companies' optimal reserve margin range. At higher reserve margin levels, the Companies' cost of carrying additional generating capacity is greater, but the risk and associated costs of shedding firm load due to generation shortages are lower. In addition, at higher reserve margins, the Companies' reliance on neighboring markets and the need to dispatch higher cost generating resources is reduced. At lower reserve margin levels, costs may be lower but the risk of load shedding is increased.

[16] 2x1 NGCC and wind units were the most economical options in a $CO_2$-constrained world.

In the analysis, the cost of the Companies' generating portfolio was evaluated at different reserve margin levels by adding or subtracting simple-cycle combustion turbine ("SCCT") capacity. "Scarcity cost" is defined as the sum of unserved energy costs, the cost of purchased power greater than the marginal cost of a SCCT, and the cost of dispatching other generating resources more expensive than a SCCT. As SCCT capacity is added, scarcity costs will decrease.

The Strategic Energy Risk Valuation Model ("SERVM") from Astrape Consulting was used to estimate scarcity costs as well as the number of loss-of-load events per year over a range of reserve margin levels. Scarcity costs and the likelihood of loss-of-load events are impacted by the uncertainty in weather, unit availability, economic load growth, the ability to import power from neighboring regions, and other factors. To properly capture the cost of high-impact, low-probability events, SERVM evaluates thousands of scenarios that encompass a wide range of the input variables.

The analysis determined the Companies' economic reserve margin range as well as the reserve margin needed to meet physical reliability standards. To determine the economic reserve margin range, scarcity costs and the cost of carrying SCCT capacity were estimated over a range of reserve margin levels. The economic reserve margin is the reserve margin where the sum of these costs is minimized.

In North America, the most commonly used physical reliability guideline is the "1-in-10 loss-of-load event" ("1-in-10 LOLE") guideline. Systems that adhere to this guideline are designed to experience one loss-of-load event in ten years. The reserve margin that meets the 1-in-10 LOLE guideline does not necessarily coincide with the economically optimal reserve margin.

In the reserve margin analysis, the planning reserve margin range was determined by considering the economic reserve margin range as well as the reserve margin needed to meet physical reliability guidelines. The Companies' reserve margin analysis is titled *2014 Reserve Margin Study* and is contained in Volume III, Technical Appendix.

**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 the least cost strategy for meeting future load requirements by analyzing the economics of various configurations of combined-cycle units and renewable generation, monitoring the development of environmental regulations, evaluating the potential for retiring existing units, and reviewing purchased power as an option to delay generation construction. In addition, the Companies will continue to develop ways to incorporate uncertainty into their analyses.

**8.(5)(f) Actions to be undertaken during the 15 years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment; and**

The Acid Deposition Control Program was established under Title IV of the CAAA and applies to the acid deposition that occurs when $SO_2$ and nitrogen oxides $NO_X$ are transformed into sulfates and nitrates and combine with water in the atmosphere to return to the earth in rain, fog or snow. Title IV's purpose is to reduce the adverse effects of acid deposition through a permanent reduction in $SO_2$ emissions and $NO_X$ emissions from the 1980 levels in the 48 contiguous states. With the CAIR implementation in 2009 for $NO_X$ and 2010 for $SO_2$, the further reductions in $SO_2$ and $NO_X$ aided in reducing ozone and fine particulate ("$PM_{2.5}$") in the affected regions of the country (including Kentucky). However, with the future implementation of new NAAQS for $NO_X$, $PM_{2.5}$, Ozone, and $SO_2$, future promulgation or replacement of CSAPR and rules covering hazardous air pollutants, requirements of Clean Water Act Section 316(b), potential issuance of effluent guidelines under the Clean Water Act and possible rules requiring the reduction of greenhouse gas emissions, it is certain that significant capital investments will be needed in the future to meet these new requirements.

**$SO_2$**

Phase II of the CAAA's Acid Deposition Control Program, described previously in Section 8.(5)(b) under *Clean Air Act Compliance Plan*, established a cap on annual $SO_2$ emissions of approximately 8.9 million tons by the year 2000. The legislation obtained these $SO_2$ emission reductions from electric utility plants of more than 25 MW (known as "affected units") through the use of a market-based system of emission allowances. Once allocated, allowances may be used by affected units to cover $SO_2$ emissions, banked for future use, or sold to others.

**Clean Air Interstate Rule ($SO_2$ portion)**

As stated previously in section 8.(5)(b), the CAIR introduced a need for further reduction of $SO_2$ emissions. However, legal proceedings have found CAIR to be a "fatally-flawed" rule and it was remanded back to EPA for further consideration. Additionally, the court ruling did leave CAIR in place until a new rule could be promulgated. CAIR continues to use the cap-and-trade emission allowance program. The Companies retain enough emission allowances to cover the level of emissions that occur. The CAIR $SO_2$ program began in 2010 and included a Phase II beginning in 2015 to further reduce $SO_2$ allowances and associated emissions. CAIR uses the existing $SO_2$ allowance allocations that the Companies (and all other utilities impacted by CAIR) have already received under the Acid Rain Program for 2010 through 2042. However, CAIR states affected facilities l surrender allowances at a greater rate than is currently required: on a 2-

for-1 within Phase I. One caveat is that pre-2010 Acid Rain Program $SO_2$ allowances (i.e., banked allowances) retained their full value.

To curtail the need for purchasing $SO_2$ allowances, the Companies completed construction of FGD equipment on KU's Ghent Units 2[17], 3 and 4 and E.W. Brown Units 1, 2, and 3. Construction was completed at Ghent in 2009 and at E.W. Brown in 2010.

**Clean Air Transport Rule ($SO_2$ portion)**

However, the CAIR was remanded back to EPA on July 11, 2008 by the D.C. Circuit Court for further reconsideration. The original proposed effort by EPA in reconsideration of the CAIR was to replace it with a new transport rule originally called CATR. On August 6, 2011, the EPA published in the federal register the final version under the title of CSAPR. The reductions prescribed by the CSAPR were similar to the CAIR reductions for the Companies. Under CSAPR, less reduction of $SO_2$ was required during 2012-2013, but more reduction was required for 2014 and beyond. It included limitations on interstate trading and prescribed a new trading program for $SO_2$ allowances that did not allow for previously banked allowances to be used in this new program.

Due to petitions against the CSAPR primarily concerning issues with EPA methodology of allocations for alleviating States contributions downwind Ozone and $PM_{2.5}$ issues, the CSAPR was stayed by the D.C. Circuit court in December of 2011. On August 12, 2012 the D.C. Court of Appeals vacated the CSAPR, remanded it to EPA for rewriting, and ordered EPA to continue to administer the CAIR rule until the rewrite is complete and promulgated.

[17] 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 EPA and a number of environmental groups, states, and others petitioned the D.C. Circuit Court of Appeals for a full court re-hearing of the CSAPR. The petition was denied on August 12, 2012. A similar appeal was then filed with the Supreme Court. In June 2013, the Supreme Court agreed to rehear arguments to re-instate the CSAPR. The initial arguments were heard in December of 2013 with a final decision expected in the Spring 2014. The CAIR rule will continue to be implemented until a decision by the Supreme Court directs otherwise or a separate action by EPA to address transport of emissions affecting downstream NAAQS attainment is promulgated.

**New National Ambient Air Quality Standards for $SO_2$**

EPA published a final rule on June 22, 2010 to revise the current primary $SO_2$ NAAQS. The new NAAQS for $SO_2$ is a 1-hour primary (i.e., health based) $SO_2$ standard of 75 ppb, based on the three year average of the fourth highest of the 1-hour maximum concentrations. The historical 3-hour $SO_2$ data (from 2009 – 2011) at the Watson Lane monitor location in Jefferson County was utilized to designate the area adjacent to the Mill Creek Generating Station in non-attainment of the new standard. Kentucky made their $SO_2$ attainment recommendations in January, 2013 and the initial non-attainment designations approved by EPA were published in the Federal Register in October, 2013. Kentucky must submit their state implementation plan ("SIP") that will contain enforceable emission limitations or control measures on sources contributing to non-attainment by April, 2015 in order to achieve attainment by October, 2018. The new FGDs currently underway at the Mill Creek facility should allow for emission levels to be achieved as needed for compliance.

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

**$NO_X$**

The Acid Deposition Control Program of $NO_X$ under the CAAA is not an allowance-based program, but instead established annual $NO_X$ emission limitations based on boiler type to achieve emission reductions. $NO_X$ emission reduction controls must be in place when the affected unit is required to meet the $NO_X$ standard. The maximum allowable $NO_X$ emission rates for Phase I are 0.45 lb $NO_X$ /MMBtu for tangentially-fired boilers and 0.50 lb $NO_X$ /MMBtu for dry bottom, wall-fired boilers. For Phase II, the maximum allowable $NO_X$ emission rates are 0.40 lb $NO_X$ /MMBtu for tangentially-fired boilers and 0.46 lb $NO_X$ /MMBtu for dry bottom, wall-fired boilers.

All of KU's affected units complied with the Phase II $NO_X$ reduction requirements through a system-wide $NO_X$ emissions averaging plan (average Btu-weighted annual emission limit). Compliance was achieved through the installation of advanced low $NO_X$ burners on Ghent Units 2, 3 and 4.

All of the LG&E affected units complied with the Phase II $NO_X$ reduction requirements on a "stand-alone" or unit-by-unit $NO_X$ emission limitation basis. All of the LG&E units took advantage of the "early election" compliance option under the $NO_X$ reduction program. EPA allowed "early election" units to use the Phase I $NO_X$ limits, thus avoiding the more stringent Phase II $NO_X$ limits. All of the Companies' generating stations operate below their $NO_X$ compliance obligations.

**$NO_X$ SIP Call**

The $NO_X$ SIP Call was promulgated under Title I of the CAAA of 1990 to control the formation and migration of ozone resulting from the presence of $NO_X$ in the atmosphere. Title I requires all areas of the country to achieve compliance with the NAAQS for ozone, or ground-level smog. In September 1998, EPA finalized regulations (known as the "$NO_X$ SIP Call") to address the regional transport of $NO_X$ and its contribution to ozone non-attainment in downwind areas. EPA maintained that $NO_X$ emissions from the identified states "contribute significantly" to non-attainment in downwind states and that the SIPs in these states were therefore inadequate and had to be revised. EPA's $NO_X$ SIP Call required 19 eastern states (including Kentucky) and the District of Columbia to revise their SIPs to achieve additional $NO_X$ emissions reductions that EPA believed necessary to mitigate the transport of ozone across the Eastern half of the United States and to assist downwind states in achieving compliance with the ozone standard. The final rule required electric utilities in the 19-state area to retrofit their generating units with $NO_X$ control devices by the ozone season of 2004.

The Companies developed a $NO_X$ SIP Call compliance plan (as outlined in KPSC Case Nos. 2000-386 and 2000-439) which resulted in compliance with the $NO_X$ reduction requirements at the lowest combined capital and O&M life cycle costs across the Companies' generation fleet. The plan implemented $NO_X$ emission reduction technologies on a lowest "$/ton" of $NO_X$ removed basis, to provide flexibility should regulatory or judicial changes affect the level or the timing of the $NO_X$ reduction required.

In fulfillment of the $NO_X$ SIP Call compliance plan, as mentioned in Section 8(5)(b) under *Clean Air Act Compliance Plan*, $NO_X$ emissions from the Companies coal-fired generating units were reduced through the installation of SCRs on six of the Companies' generating units. Additional $NO_X$ control technologies (including advanced low-$NO_X$ burners and overfire air systems) were also installed on nearly every generating unit in the system to reduce the $NO_X$ formed in the combustion zone of the boiler. Additionally, neural network software was installed on many of the generating units to enable better control of the boiler combustion process.

**Cross-State Air Pollution Rule ($NO_X$ portion)**

As mentioned previously in 8.(5)(b), EPA developed the CAIR rule to curtail interstate emissions and finalized it on March 10, 2005. The CAIR $NO_X$ program began in 2009 and included a Phase II beginning in 2015 to further reduce $NO_X$ allowances and associated emissions. However, legal proceedings found CAIR to be a "fatally-flawed" rule and it was remanded by to EPA for further consideration. Additionally, the court ruling did leave Phase I of CAIR in place until a new rule could be promulgated. Phase I of the rule was implemented through a "cap-and-trade" allowance program similar to the $NO_X$ SIP Call regulation. Under CAIR for $NO_X$, the EPA allocated a predetermined amount of allowances to each state and the states determined how to allocate those to individual affected units. Additionally, emissions began to be counted on a year-round basis (i.e., the annual program) beginning in 2009 in addition to continuing an ozone season program. This meant that controls (i.e., SCRs) have been run on a year-round basis to maintain compliance.

The original proposed efforts by EPA to replace CAIR were referred to as CATR). The CAIR $NO_X$ program began in 2009 and the $SO_2$ program began in 2010. It included a Phase II beginning in 2015 to further reduce $NO_X$ and $SO_2$ allowances and associated emissions.

On August 6, 2011, the EPA published in the federal register the final version under the title of CSAPR. The reductions prescribed by the CSAPR were similar for to the CAIR reductions for the Companies. For $NO_X$, CSAPR included a two-phase program with significantly less reduction required by the Companies for the first phase by 2012 and somewhat less reduction required for the second phase by 2014 and beyond. The CSAPR included limitations on interstate trading.

Due to petitions against the CSAPR primarily concerning issues with EPA methodology of allocations for alleviating States contributions to downwind Ozone and $PM_{2.5}$ issues, the CSAPR was stayed by the D.C. Circuit court in December of 2011. On August 12, 2012 the D.C. Court of Appeals vacated the CSAPR, remanded it to EPA for rewriting, and ordered EPA to continue to administer the CAIR rule until the rewrite is complete and promulgated.

**NAAQS for $NO_2$**

On February 9, 2010, EPA published a final rule which revised the Primary National Ambient Air Quality Standard for $NO_2$. It became effective on April 12, 2010. EPA adopted a new 1-hour standard of 100 ppb and retained the existing annual average standard of 53 ppb. Based on existing air quality data in Kentucky, all areas are currently well below these standards. However, the new rule stipulated that additional new air quality monitor locations be established. Emphasis is to be placed on locating these monitors near major roadways in large cities where the highest concentrations are expected; but additional monitors to represent community-wide air quality may also be required in large cities. The additional monitors are to be located between in phases from 2014 to 2017 and will be utilized in development of future revisions to the $NO_2$ standard.

The immediate potential impact for the Companies is that major new sources or modifications to existing sources will have to demonstrate, through air quality modeling, that they do not cause or contribute to a violation of the standard. EPA is also planning to evaluate whether changes to Prevention of Significant Deterioration ("PSD") air quality increments are needed. If so, this could place further limits on the allowable amount of increased emissions from a new or modified source.

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

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

**Hazardous Air Pollutants**

On May 18, 2005, EPA delisted electric generating units from the list of sources subject to hazardous air pollutant controls under Section 112(c) of the Clean Air Act and promulgated the CAMR which established a two phase "cap and trade" program for reduction of mercury emissions from those units. Then, on February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAMR on the grounds that EPA failed to follow the correct procedures for delisting electric generating units from regulation under Section 112(c). In February 2009, EPA decided to drop any further legal proceedings regarding CAMR and began focusing on developing a rule to set MACT standards that would apply to all electric generating units that are major sources of hazardous air pollutants (including mercury, other metals, dioxins and other organic compounds).

In January 2010, EPA submitted an information collection request to the electric generating industry to gather more data (including requesting new emissions testing) to aid in the development of the new MACT standards. EPA subsequently developed final rules to establish National Emission Standards for Hazardous Air Pollutants for the coal- and oil- fired electric utility industry. The MATS rule was published in the Federal Register on February 16, 2012 that set emission limits for mercury, acid gases, toxic metals, and organics including dioxins and furans based on the MACT for the industry. The emission standards within this rule have instigated multiple installations of pulsed jet fabric filters for additional control of toxic metals and shutdown of older coal-fired generation, some of which to be replaced with new natural gas combined cycle generation. The compliance date is April 16, 2015; however, the rule allows the permitting authority to grant up to one year extension based on submittal of a justifiable request.

**New NAAQS for Ozone and PM**

***Ozone***

In 1997, the EPA issued the 8-hour ozone NAAQS as a replacement for the 1-hour ozone standard promulgated in 1979. The standard was designed to protect the public from exposure to ground-level ozone. Ground-level ozone is formed when emissions of $NO_X$ and volatile organic compounds react chemically in the presence of sunlight. The new standard was implemented because EPA had information demonstrating that the 1-hour ozone standard was inadequate for protecting human health.

On April 15, 2004, EPA released Phase I of the implementation rule which included designating eight counties within Kentucky as non-attainment. Those Kentucky Counties included Jefferson, Oldham, Boone, Bullitt, Kenton, Campbell, Boyd and Christian. The classifications took effect on June 15, 2004. On July 5, 2007, EPA approved a re-designation of Jefferson, Oldham, Bullitt and Boyd Counties to attainment status, based on a submittal of improved ambient monitoring data by the Kentucky Division for Air Quality. However, EPA continued to review the effectiveness of the ozone NAAQS.

On March 12, 2008, EPA again lowered the primary standard to 0.075 ppm. Several counties in Kentucky had recent monitoring data that are above that level. As a result, Jefferson

County was designated "moderate" non-attainment with the 2008 NAAQS for ozone of 0.075 parts per million ("ppm"). With record high temperatures during the summer of 2012, the Ozone standard remains in non-attainment with the inclusion of 2012 data. However, there were no exceedances monitored in Jefferson County in 2013. With consideration of the shutdown of three coal-fired units at the Cane Run Station in 2014 and additional reductions of coal-fired generation (i.e., retirement of two coal-fired units) at the Duke Energy-Gallagher Station in New Albany, Indiana. The Ozone non-attainment in Jefferson County is expected to be satisfactorily mitigated. As a result, additional reductions on the Companies' units to meet the 2008 Ozone standard are not expected. On January 7, 2010, EPA proposed an even lower primary ozone standard in the range of 0.060 and 0.070 ppm measured over eight hours. At the same time, EPA proposed a new seasonal secondary standard in the range of 7 to 15 ppm. EPA withdrew their proposal due to insufficient data and is planning to propose a revision in 2014 that will likely become final in 2015. Once the final standard is promulgated, Kentucky will have up to three years to establish attainment status designations. Kentucky will then have one year to submit a SIP incorporating the new NAAQS and plans for bringing all areas into attainment with the new standard. EPA will then have one year to approve Kentucky's SIP submittal and typically, non-attainment areas will have at least three years (approximately until 2022) to obtain attainment status following EPA's approval. The developments and implications of the new standard will continue to be monitored by the Companies.

***PM/PM$_{2.5}$***

In 1997, EPA adopted the fine particulate NAAQS, which regulates particulate matter measuring 2.5 micrometers in diameter or smaller (PM$_{2.5}$). In general, PM$_{2.5}$ is generated by automobiles, power plants, and industrial sources, but also includes many naturally-occurring dust-like particulates such as pollen and soot. Some $PM_{2.5}$ comes in the form of sulfates, nitrates and carbon-containing compounds. Additionally, gaseous emissions of $SO_2$ and $NO_X$ can transform into sulfates and nitrates in the atmosphere.

On April 5, 2005, EPA re-issued the list of non-attainment areas in Kentucky which included Boone, Boyd, Bullitt, Campbell, Jefferson, Kenton, and part of Lawrence counties. This started the clock on the need to revise Kentucky's SIP by April 2008.

However, on September 21, 2006, EPA released a revision to the PM NAAQS with a December 18, 2006 effective date. The primary annual $PM_{2.5}$ standard remained the same (15 $\mu g/m^3$). The primary 24-hour $PM_{2.5}$ standard was lowered from 65 to 35 $\mu g/m^3$. The 24-hour $PM_{10}$-$PM_{2.5}$ standard was retained at 150 $\mu g/m^3$. The annual $PM_{10}$-$PM_{2.5}$ standard was revoked. On December 22, 2008, EPA finalized their non-attainment designations for Kentucky which included Boone, Boyd, Bullitt, Campbell, Jefferson, Kenton, McCracken and parts of Muhlenberg and Lawrence counties.

In February 2009, the D.C. Circuit Court of Appeals remanded the new standards back to EPA. As a result, EPA began working on a proposed revision that was originally expected in 2011. Of additional note, in October 2009, EPA re-designated all counties in Kentucky as attainment with the 1997 24-hour standard, based on a re-evaluation of monitoring data performed and submitted by the Kentucky Division for Air Quality ("KyDAQ"). However, an audit was conducted by the KyDAQ in 2013 that found data quality issues with the $PM_{2.5}$ monitors operated by the Louisville Metropolitan Air Pollution Control District ("LMAPCD"). Although Jefferson County is still currently classified as non-attainment for the 1997 24-hr standard, the KyDAQ has recommended a status of attainment/unclassifiable based on valid 2011 to 2013 data and the general downward trend of ozone. Additionally, KyDAQ has recommended the use of data from monitors located near Jefferson County located in southern Indiana in support of attainment status. At this time, that process is still under review by EPA.  .

In December of 2012, the EPA promulgated a new NAAQS for $PM_{2.5}$ that lowered the 24-hour standard from 15 $\mu g/m^3$ to 12 $\mu g/m^3$.  Based on monitoring data in Kentucky for 2009-2011, Jefferson County would not meet the lowered standard.  Attainment designations have not been established at this time.  However, as a result of the shutdown of coal-fired generation at the Cane Run facility in 2015 and the installation of pulsed jet fabric filters on the Mill Creek coal-fired units by 2016, issues with attainment status are expected to be mitigated.

**Clean Air Visibility Rule**

In April 1999, EPA issued final regulations known as the Clean Air Visibility Rule ("CAVR"), formerly known as the Regional Haze Rule, to protect 156 pristine (Class I) areas of the U.S., which are primarily national parks and wilderness areas.  The goal of the regulatory program is to achieve natural background levels of visibility, that is, visibility unimpaired by manmade air pollutants in Class I areas, by 2064.  Kentucky has one designated Class I area, Mammoth Cave National Park, and is required to assess visibility impacts to this area.

CAVR gives states flexibility in determining reasonable progress goals for the areas of concern, taking into account the statutory requirements of the CAAA.  The final regulation requires all 50 states to reduce emissions of fine particulate matter and other air pollutants, including $SO_2$ and $NO_X$, and any other pollutant that can, via airborne transport, travel hundreds of miles and affect visibility in Class I areas.  Incremental improvements of visibility in the affected areas are required to be seen early in the next decade.

In June 2001, the EPA proposed guidelines on what constituted Best Available Retrofit Technology ("BART") for the reduction of regional haze issues.  The BART requirement applies to all facilities built between 1962 and 1977 that have the potential to emit more than 250 tons per year of visibility-impairing pollution. The guidelines are to be used by the states to determine how to set air pollution limits for facilities in 26 source categories, including power plants. EPA's guidance was remanded back to the agency by the D.C. Circuit to eliminate from the source categories those emission points whose contribution to visibility impairment is negligible. On May 5, 2004, new step-by-step guidance was published for states to implement the rule. The guidance additionally included a determination that emissions of $SO_2$ and $NO_X$ should not be included in modeling the impact of coal-fired generating units in compliance with the CAIR rule, otherwise referred to as "CAIR equals BART". The emissions from the Companies affected units were evaluated for their potential visibility impact on affected Class I areas. From that data, Mill Creek Units 1-4 were the only units identified as having a significant visibility impact. Following an engineering analysis, it was determined that current plans for control technology installations of dry sorbent injection systems would meet the requirements for BART. This data along with all other affected facilities information was submitted to the KyDAQ. They submitted a CAVR SIP in December 2007 to EPA and the National Park Service. Subsequently, KyDAQ submitted a revision to the SIP on May 27, 2010. With consideration that the CAIR rule was remanded, final approval is pending based on the outcome of re-instatement or replacement of the CSAPR rule as described above.

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.

Following remand of the CAIR rule, EPA determined that compliance with "CSAPR equals BART". EPA has since issued an opinion memorandum that states consider units in compliance with CAIR can utilize the "CAIR = BART" analysis for compliance determination. In addition, KyDAQ has stated their agreement that 'CAIR = BART". With the forthcoming Supreme Court Ruling that will determine if CSAPR is re-instated or if EPA must develop new rules, it is expected the EPA will include associated discussion of use of a transport emissions reduction program with demonstration of visibility regulations.

**Clean Water Act – Section 316(b)**

The Clean Water Act section 316(b) requires the reduction of adverse environmental impact upon aquatic populations by using BACT for water withdrawn from a water source for cooling purposes. In July 2004, EPA issued a rule for the utility industry which included two "performance standards" requiring facilities to reduce deaths of aquatic life from impingement by 80-95 percent and for some facilities, also reduce entrainment of fish, eggs and larvae by 60-90 percent. The regulation was challenged by environmental groups as not strong enough to protect aquatic populations and was ultimately struck down by the U.S. 2nd Circuit Court in 2007. EPA rescinded the rule on January 6, 2008 and is currently drafting a new set of regulations.

EPA anticipates finalizing a new rule in May 2014; but, that timeframe may be extended to 2015.. The Companies expect both industry and environmental groups will utilize the court system to again challenge the new rule and possibly delay implementation deadlines. The regulations will address both impingement and entrainment issues, thus affecting the Companies facilities, including those already equipped with closed cycle cooling (cooling towers).

Possible requirements within the rule include: cooling towers on all active units, “helper” towers on once-thru cooling units for use during spawning season and low flow periods, fine mesh screens (1-2 mm) for water intake, fish return systems associated with the screens, and/or annual in-stream fish studies. These potential capital investments could be required within the time period of this IRP document. The Companies will continue to monitor this issue.

**Clean Water Act – Effluent Guidelines**

In August 2005, EPA proposed a plan to review the effluent guidelines for the steam electric industrial category. EPA determined that the steam electric industry: (1) discharged the highest “toxic weighted pounds equivalent” of the 55 industries with existing guidelines based on National Pollution Discharge Elimination System data, and (2) ranked fourth for toxic loadings based on Toxic Release Inventory data. These rankings along with the advanced age of the steam electric guidelines (last updated in 1982) mean the industry remains a significant target for guidelines revision.

On December 20, 2006, the final version of the effluent guideline plan did not name the steam electric industry for revision. However, a two-year study (2007-2008) was proposed to determine if the guidelines for particular areas should be revised. The areas of interest include cooling water, ash handling, coal pile runoff, air pollution control devices and other miscellaneous waste streams.

In October 2009, EPA determined that it would revise the steam-electric industry standards. In June 2010, EPA issued a very detailed questionnaire to over 500 utilities across the nation that was aimed at assisting EPA in revising the standards. Based on the depth of the questionnaire, it is anticipated that it will take EPA several years to digest the information. EPA issued proposed draft regulations in May 2013 that are due to be finalized by May 2014, but, that date may likely be extended into 2015. The proposed regulations could require capital investments for treatment facilities within the time period of this IRP document. The Companies will continue to monitor this issue.

**Greenhouse Gases**

On September 22, 2009, EPA issued its mandatory GHG emissions reporting rule. Facilities with $CO_2e$ of more than 25,000 metric tons or an aggregated maximum rated heat input capacity of more than 30 MMBtu/hour are subject to the GHG emissions reporting rule. Annual reporting to EPA began March 31, 2011. Sources required to report include: power plants, miscellaneous stationary combustion sources, and emissions pertaining to the gas supplied to customers of the Companies. On November 2, 2010, the reporting regulation was expanded to include reporting of SF6 emissions from electric transmission and distribution equipment and methane, carbon dioxide and nitrogen oxide emissions from natural gas processing plants, natural gas transmission compression operations, natural gas underground storage and natural gas distribution activities. Reporting for these activities began with the 2010 operating year.

On March 13, 2010, EPA issued the greenhouse gas “Tailoring Rule” which became effective on January 2, 2011. This rule sets thresholds for requiring permitting of greenhouse emissions. Between January 2011 and June 2011, sources subject to any other PSD rule that undergo modification will have to get a permit for any applicable GHG emissions if they total more than 75,000 tons per year (“tpy”) $CO_2e$. The threshold was set at 100,000 tpy $CO_2e$ for new sources and 75,000 tpy $CO_2e$ for modified sources effective by July 2011. Therefore, future evaluations of major projects are required to determine whether they trigger the need to perform BACT evaluations of GHG emissions.

In December 2010, EPA also announced that they plan to propose NSPS regulations for GHG emissions from power plants by July 26, 2011 with potential finalization to occur in May 2012. These new rules would set emission requirements for new and modified EGUs and set guidelines for existing EGUs. EPA indicated that they will coordinate these rules with other rules due out near the same time (i.e., hazardous air pollutants, Clean Air Transport Rule). The EPA did not follow through with this plan.

However, on June 25, 2013, President Obama announced his “Climate Action Plan” which laid out a timeline and targets for regulatory development to reduce GHG emissions. In response, EPA issued a proposed NSPS for GHG emitted from new fossil fuel fired electric generation sources. The proposal was published in the Federal Register on January 8, 2014 and establishes the effective date of applicability for the specific standards limiting $CO_2$ emissions from new fossil fuel fired electric generating facilities including coal fired, natural gas fired (if greater than 1/3 of the maximum potential generation is used on the grid), and IGCC units.

At this time, until the proposed GHG NSPS is promulgated, energy efficiency is considered BACT. However, the currently proposed GHG NSPS establishes partial carbon collection and storage (“PCCS) as the best system of emission reduction. The proposal is expected to be promulgated by January of 2015. At that time, if the rule is promulgated as proposed, PCCS will become BACT and be triggered if new source will emit greater than 100,000 tons per year $CO_2e$ or a modification to an existing source is evaluated to cause an increase of 75,000 tons per year $CO_2e$ .

Additionally, EPA is targeted to propose regulations by June of 2014 for GHG NSPS applicable to existing fossil fuel fired electric generating units. President Obama’s Climate Action Plan targeted 17 percent reductions from 2005 emissions by 2020. Until more information is provided, the potential impact of these rules is uncertain. The Companies will continue to monitor this issue.

**Coal Combustion Residuals**

Within the next few years, regulatory changes are expected in the permitting and management practices for CCR from coal ash and FGD systems whether they are managed in ash treatment basins (ash ponds) or landfills. Historically, water discharges have influenced CCR management strategies at company facilities. Additional restrictions will likely be placed on discharges permitted by the Kentucky Pollutant Discharge Elimination System from either impoundments or landfills surface runoff (and may also address groundwater monitored aquifers).

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

EPA has not yet selected a final option and is unlikely to do so before December 2014. When published, the regulation will likely have a five year implementation window. This means that existing facilities would require upgrade or closure. The Companies will continue to monitor 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 2014 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

The Companies developed optimal expansion plans over multiple natural gas price, load, and $CO_2$ scenarios. For each of the scenarios evaluated, the following information is provided in *Appendix to Sections 8 and 9 – Scenario Data* (see Volume III, Technical Appendix):

- Present (base year) value of revenue requirements
- Real value of revenue requirements
- Nominal value of revenue requirements
- Average rate, defined as the nominal revenue requirements divided by the total system energy requirements (in ¢/kWh)

The discount rate used in present value calculations is 6.52 percent, which is the combined company after-tax incremental weighted average cost of capital. The inflation rate used in the real value calculations is 1.8 percent.