COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2011 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2011-00140

ORDER

The Commission initiated this proceeding for its Staff to conduct a review of the 2011 Joint Integrated Resource Plan ("IRP") of Louisville Gas and Electric Company and Kentucky Utilities Company pursuant to 807 KAR 5:058. Attached in the appendix to this Order is the Staff's report summarizing its review of the IRP. This report is being entered into the record of this case pursuant to 807 KAR 5:058, Section 11(3).

Based on the evidence of record, the Commission finds that the Staff's report represents final substantive action in this matter and that this case can now be closed.[1]

IT IS THEREFORE ORDERED that this case is closed and removed from the Commission's docket.

By the Commission

ENTERED

MAR 13 2013

KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Executive Director

[1] The Staff report can be accessed via the Commission's website at psc.ky.gov under "Utility Information—Industry Specific Info—Electric."

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2011-00140 DATED MAR 13 2013

Kentucky Public Service Commission

Staff Report on the

2011 Integrated Resource Plan

of Louisville Gas and Electric Company

and Kentucky Utilities Company

Case No. 2011-00140

March 2013

SECTION 1

INTRODUCTION

807 KAR 5:058, promulgated in 1990 and amended in 1995 by the Kentucky Public Service Commission ("Commission"), established an integrated resource planning process that provides for regular review by the Commission Staff ("Staff") of the long-range resource plans of the Commonwealth's six major jurisdictional electric utilities. The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electricity were being examined and pursued and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU" collectively "LG&E/KU" or "Companies") submitted their Joint 2011 Integrated Resource Plan ("IRP") to the Commission on April 21, 2011. The IRP includes the LG&E/KU plan for meeting their customers' electricity requirements for the period 2011-2025.

On May 16, 2011, an Order was issued which established a procedural schedule for this proceeding. The schedule allowed two rounds of data requests to LG&E/KU, written comments by intervenors, and reply comments by the Companies.

Intervening in this matter were the Attorney General of the Commonwealth of Kentucky ("AG"), Kentucky Industrial Utility Customers ("KIUC"), and Rick Clewett, Janet Overman, Gregg Wagner, the Natural Resources Defense Council and the Sierra Club ("Environmental Intervenors"). Only the Environmental Intervenors provided comments on the LG&E/KU IRP.

LG&E and KU are investor-owned utilities that supply electricity and natural gas to customers located primarily in Kentucky. They are subsidiaries of LG&E and KU Energy LLC ("LKE"), which is a subsidiary of PPL Corporation ("PPL"). PPL acquired LKE from E.ON AG in November 2010. In conjunction with the PPL acquisition, LKE, which had formerly been known as E.ON U.S, LLC, had its name changed to LG&E and KU Energy LLC. The Companies are owners and operators of interconnected electric generation, transmission and distribution facilities. They achieve economic benefits through the operation of an interconnected and centrally dispatched system and through coordinated planning, construction, operation, and maintenance of their facilities.

LG&E supplies electricity and natural gas in the Louisville, Kentucky, greater metropolitan area. It provides electric service to approximately 400,000 customers in Jefferson County and 11 surrounding counties with a total service area covering approximately 700 square miles. It supplies natural gas to over 320,000 customers.

KU supplies retail electricity in 77 Kentucky counties to approximately 545,000 customers in a service area covering approximately 6,600 non-contiguous square miles, in five Virginia counties as Old Dominion Power ("ODP") and to five customers in Tennessee. It sells wholesale electricity to 12 municipal electric systems in Kentucky.

The Companies' net summer generation capacity in 2011 was 8,001 Megawatts ("MW"). This consisted of 5,808 MW of coal-fired capacity, 2,115 MW of gas-fired capacity and 78 MW of hydroelectric power. Major industries located in the LG&E/KU service territories include coal mining, automotive manufacturing, agriculture, primary metals processing, chemical processing, electrical machinery manufacturing, and paper and paper products manufacturing. The Companies' highest actual combined system peak demand of 7,175 MW occurred on August 4, 2010, a date on which LG&E reached its all-time peak demand of 2,852 MW. KU experienced its highest summer peak demand of 4,354 MW on that same day; however, its all-time system peak demand of 4,640 MW occurred on January 16, 2009.

The purpose of this report is to review and evaluate the Companies' Joint IRP in accordance with 807 KAR 5:058, Section 12(3), which requires Commission Staff to issue a report summarizing its review of each IRP filing made with the Commission and make suggestions and recommendations to be considered in future IRP filings. Staff recognizes that resource planning is a dynamic ongoing process. Thus, this review is designed to offer suggestions and recommendations to LG&E and KU on how to improve their resource plan in the future. Specifically, Staff's goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The report also includes an incremental component, noting any significant changes from the Companies' most recent IRP filed in 2008.

LG&E and KU state that the mandate for their Joint IRP is to meet future energy requirements within their service territories at the lowest possible cost consistent with reliable service. The Companies assert that they have an ongoing resource planning process and their IRP represents only one snapshot in time of that process, which is fundamental to all corporate planning. The various sections of their IRP define ongoing and planned activities that collectively make up that process. LG&E and KU state that certain assumptions are made in their planning decisions and, as such, are subject to various degrees of risk and uncertainty. The Companies examine the economics and practicality of supply-side and demand-side options in order to forecast the least cost options available to meet forecasted customer needs.

The LG&E/KU resource planning process contains the following:

- Establishment of reserve margin criteria;
- Assessment of the adequacy of existing generating units and purchased power agreements;
- Assessment of potential purchased power market agreements;
- Assessment of demand-side options;

- Assessment of supply-side options; and
- Development of the optimal economic plan from the available resource options.

While their IRP represents the Companies' analysis of the best options to meet customer needs at a given point in time, the resource plan is reviewed and re-evaluated prior to implementation. If new generation is needed or demand-side options are to be expanded, the Companies must receive Commission approval prior to implementation.

The Companies' combined summer peak is expected to increase from 6,935 MW, their weather-normalized 2010 peak, to 8,957 MW in 2025, reflecting a growth rate of 2.1 percent per year. Their winter peak load is expected to increase from 6,110 MW to 8,086 MW over the same period, reflecting a growth rate of 1.9 percent. Energy requirements are projected to increase from 35,382,000 MWh in 2010 to 44,590,000 MWh in 2025, which reflects an annual growth rate of 1.5 percent.

The LG&E/KU IRP was developed based on a minimum reserve margin criterion of 16 percent. Based on DSM programs in place at the time the IRP was filed, along with new programs proposed in Case No. 2011-00134,[1] the Companies expect to have a 500 MW reduction in summer peak demand by the end of 2017. LG&E/KU's base case resource plan includes the retirement of 797 MW of coal-fired capacity at the Cane Run, Green River and Tyrone generating stations, and the addition of 2,100 MW of combined cycle gas-fired capacity.

The remainder of this report is organized as follows:

- Section 2, Load Forecasting, reviews LG&E's and KU's projected load growth and load forecasting methodology
- Section 3, Demand-Side Management, summarizes LG&E's and KU's evaluation of DSM opportunities
- Section 4, Supply-Side Resource Assessment, focuses on supply resources available to meet the Companies' load requirements and environmental compliance planning
- Section 5, Integration and Plan Optimization, discusses the Companies' overall assessment of supply-side and demand-side options and their integration into an overall resource plan

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[1] Case No. 2011-00134, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification and Continuation of Existing and Addition of New Demand-Side Management and Energy Efficiency Programs (Ky. PSC Nov. 9, 2011).

SECTION 2

LOAD FORECASTING

GENERAL METHODOLOGY

LG&E and KU subscribe to IHS Global Insight ("Global Insight") for key historical and forecast economic and demographic data. Information from both Global Insight's 2010 Long-Term Macro Forecast and its Population and Household Forecast is used in the forecasts.[2] Key inputs (projections) from these reports include: the Trend Scenario; demographic data (county level number of households, income and employment); real electricity prices; state and national gross domestic production ("GDP") projections; and other drivers such as the American Recovery and Reinvestment Act of 2009 ("ARRA"). The Trend Scenario provides a 30-year projection (2011-2040) of economic growth assuming no large shocks to the economy. Relative to the last 30 years, the growth rate in GDP, personal consumption and government spending are forecast to decrease slightly. Business investment and the balance of trade are expected to grow slightly faster that the historical rate. Based on data from the Census Bureau, the population growth rate is expected to slow. Real U.S. GDP is to grow at the average annual rate of 2.6 percent. Also, the IRP incorporates the effect on sales from ARRA, which come through increased weatherization of buildings and the effects of previous government mandates and an increased general awareness of energy efficiency.[3]

Both LG&E and KU use econometric modeling to develop forecasts of energy sales by customer class. This approach easily incorporates the effects of national, state and specific local service territory drivers affecting energy sales. Generally, most customer class forecasts are based upon at least 10 years of monthly sales data. The residential and general service sales forecasts are derived using statistically adjusted end use ("SAE") models, which blend econometric models with end use models. This technique allows for the capture of base load, heating and cooling components of energy sales; appliance saturation and efficiency trends; and efficiency, price and income effects. Normal weather assumptions are based upon the most recent 20 years ending in 2009. The Companies obtain weather data from the National Climatic Data Center, a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. The commercial forecasts are obtained from real state GDP, appliance and equipment (including HVAC) efficiencies and saturation levels, weather, establishment square footage, and real electricity prices. The large industrial customer forecasts are obtained from customers' historical use and specific information provided by individual customers.[4]

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[2] LG&E/KU IRP, Section 7.(7)(b), page 13.

[3] Id., Section 7.(7)(a) and (b), pages 11-14.

[4] Id., Sections 7.(7)(a), pages 11-12, and 7.(7)(c), pages 15-16.

HOURLY DEMAND FORECAST METHODOLOGY

Monthly energy sales forecasts for each customer class are converted from a billed to a calendar basis. Then, the hourly demand forecast is obtained through a four-step process. Using load research data to create specific customer load shape profiles, monthly calendar sales forecasts are matched to obtain class specific hourly demand forecasts. First, MetrixND is used to obtain load shapes for the Residential and General Service customer classes (there are six forecast classes for LG&E and 10 for KU, including ODP). Second, reductions to the demand forecasts as a result of increases in energy efficiency mandated by the Energy Independence and Security Act of 2007 are taken into account using MetrixLT software. Third, further reductions to demand forecasts resulting from Demand-Side Management ("DSM") programs are taken into account using MetrixLT software. Finally, system losses are taken into account to obtain the final hourly demand forecast for each customer class.

RESIDENTIAL FORECAST METHODOLOGY

The average energy use per residential customer is modeled as a function of annual heating equipment use, XHeat, annual cooling equipment use, XCool, and all other annual equipment use, XOther. XHeat is defined as the product of HeatIndex, and HeatUse. HeatIndex is a weighted average of equipment saturation levels for heat pumps, electric space heating, and electric furnaces normalized across efficiency levels. The HeatUse variable is a function of Heating Degree Days (based upon normal weather), average household size, average real income per household, the average real price of electricity and demand price elasticity.[5]

XCool is defined as the product of CoolIndex and CoolUse. CoolIndex is a weighted average of cooling equipment saturation levels for heat pumps, room air conditioners, and central air conditioners normalized across efficiency levels. The CoolUse variable is a function of Cooling Degree Days (based upon normal weather), average household size, average real income per household, the average real price of electricity and demand price elasticity. XOther is defined as the product of OtherIndex and OtherUse. OtherIndex is a weighted average of other equipment (appliance) saturation levels for electric water heaters, refrigerators, freezers, electric cooking stoves, electric dryers, dishwashers, washing machines and miscellaneous appliances across efficiency levels. OtherUse is a function of the number of billing days per year, average household size, average real income per household, the average real price of electricity and demand price elasticity.[6]

Results from a 2003 appliance saturation survey provide the base year data for various equipment saturation and efficiency levels, household size, building size, age and type. Forecasts of equipment and appliance saturation, efficiency levels and unit energy consumption levels were obtained from the Energy information Administration.

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[5] Technical Appendix Volume II - Residential Use per customer Forecast, pages 2-3.

[6] Id., pages 4-6.

Use variables are functions of weather, economic and demographic variables. This data was obtained from the National Oceanographic and Aeronautical Administration and Global Insight. The price elasticities of demand were developed by Itron.[7]

COMMERCIAL FORECAST METHODOLOGY

The average energy use per commercial customer is modeled as a function of annual heating equipment use, XHeat, annual cooling equipment use, XCool) and all other annual equipment use, XOther. As with the residential forecast methodology, XHeat is defined as the product of HeatIndex, and HeatUse. HeatIndex reflects electric space heating equipment saturation levels normalized across efficiency levels. Heating sales levels in 2004 serve as the base year for the index. The HeatUse variable is a function of monthly billing days, Heating Degree Days (based upon normal weather), commercial level economic activity, and the average real price of electricity.[8]

As with the residential forecast methodology, XCool is defined as the product of CoolIndex and CoolUse. CoolIndex is represented by cooling equipment saturation levels normalized across efficiency levels. As with the heating variable, 2004 represents the base year for the index. The CoolUse variable is a function of the number of monthly billing days, Cooling Degree Days (based upon normal weather), commercial economic activity, and the average real price of electricity. XOther is defined as the product of OtherIndex and OtherUse, as with the residential forecast methodology. OtherIndex is a weighted average of other equipment saturation levels for ventilation, water heating, cooking, refrigeration, outdoor lighting, indoor lighting, office equipment, and miscellaneous equipment across efficiency levels. OtherUse is a function of the number of billing days per year, commercial economic activity, and the average real price of electricity.[9]

LG&E SALES FORECAST

LG&E sales forecasts are based on 12 separate models. Generally, the forecast methodology is the same for both LG&E and KU.[10] LG&E's energy sales are forecast to grow from 13,104 GWh in 2011 to 15,965 GWh in 2025, which represents a 1.6 percent average annual growth rate. Summer peak demand is forecast to grow from 2,830 MW in 2011 to 3,596 MW in 2025, representing a 1.9 percent average annual growth rate.

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[7] Id., page 6.

[8] Id., Commercial Use per Customer Forecast, pages 15-17.

[9] Id., pages 1, 17-19.

[10] LG&E/KU IRP, Section 7.(7)(c) at pages 41-42.

Winter peak demand is forecast to increase from 1,933 MW in 2011 to 2,368 MW in 2025, representing a 1.6 percent average annual growth rate.[11]

LG&E RESIDENTIAL FORECAST

The LG&E residential forecast includes all customers on the Residential Service ("RS") and Volunteer Fire Department rate schedules. The residential forecast is the product of the forecast number of customers and average use per customer which is forecast using a SAE model. It is a function of weather, economic conditions, household demographics, and equipment saturation and usage levels.[12] Energy sales are forecast to increase from 4,337 GWh in 2011 to 5,244 GWh in 2025 representing a 1.5 percent average annual growth rate.[13]

LG&E COMMERCIAL FORECAST

The commercial forecast consists of two separate models: Small Commercial and Large Commercial. The Small Commercial forecast includes all customers on the Industrial Power Service ("IPS") Primary and GS Secondary rate classes (formerly the General Service rate) and is the product of an average use-per-customer (obtained using a SAE model) and a customer forecast. The customer forecast was tied to the Residential customer forecast because the two groups have historically moved together. The customer forecast was allowed to grow at a slightly lower rate than the Residential customer forecast. The Large Commercial forecast includes all customers on the Large Commercial and Large Commercial Time-of-Day rate schedules. Large Commercial energy sales are modeled as a function of weather, households and the average real price of electricity and binary variables.[14] Small commercial energy sales are forecast to increase from 1,497 GWh in 2011 to 1,904 GWh in 2025 representing a 1.9 percent average annual growth rate. Large commercial energy sales are forecast to increase from 2,388 GWh in 2011 to 3,181 GWh in 2025 representing a 2.4 percent average annual growth rate.[15]

LG&E INDUSTRIAL FORECAST AND METHODOLOGY

Because a relatively small number of customers make up a significant portion of the load, LG&E works directly with its largest customers to develop a five-year forecast.

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[11] Peak demand figures are inclusive of interruptible power and the effects of new and existing DSM programs. LG&E/KU IRP, Section 7, Tables 7.(4)(a), pages 7-8 and 7-37, and Section 8, Tables 8.(4)(a)-1 and -2, pages 8-80 and 8-81.

[12] LG&E/KU IRP, Section 7.(7)(c), pages 42-43.

[13] Id., Section 7, Tables 7.(4)(a), page 7-37.

[14] Id., Section 7.(7)(c), page 44.

[15] Id., Section 7, Tables 7.(4)(a), page 7-37.

Initially, a total industrial energy sales forecast is developed. Individual major account forecasts are used subsequently to adjust total industrial usage.

The industrial group forecast consists of two separate models: LP Power and LP-TOD/special contract. The LP forecast includes all customers on the IPS rate schedule. The forecast is a function of weather, an industrial production index, and real per-unit revenue. The IPS forecast is then split out to the IPS Primary and IPS Secondary rate classes. The LP-TOD/Special Contract forecast includes all customers on the Industrial Time-of-Day ("ITOD") rate schedule and all special contract customers. Major account customers are responsible for approximately 70 percent of the energy used in this customer class. The energy sales forecast is a function of a sector weighted industrial production index, weather and real per-unit revenue and then adjusted for any significant changes from the major account forecasts. The LP-TOD/Special Contract forecast is then split into the ITOD Primary and ITOD Secondary and Retail Transmission Service customers. The Retail Transmission Service forecast includes all customers served on a transmission level rate.[16] Taken together, industrial energy sales are forecast to increase from 2,759 GWh in 2011 to 2,943 GWh in 2025 representing a 0.5 percent average annual growth rate.[17]

LG&E LIGHTING

LG&E's lighting forecasts are the product of the number of lighting hours per month, the energy use per fixture per hour, per month, and the monthly number of fixtures. Energy use was held to 2008 levels and the number of fixtures was forecast using a trend.[18] Lighting energy sales are forecast to decrease slightly from 34 GWh in 2011 to 29 GWh in 2025.[19]

KU SALES FORECASTS

KU sales forecasts are based on 28 separate models covering three distinct jurisdictional groups: Kentucky retail (86 percent of sales), Virginia retail (5 percent of sales), and FERC regulated sales to 12 Kentucky municipal utilities (9 percent of sales).[20] KU's energy sales are forecast to grow from 22,915 GWh in 2011 to 28,625 GWh in 2025, which represents a 1.8 percent average annual growth rate.[21] For KU and LG&E combined, summer peak demand is forecast to grow from 7,091 MW in 2011 to 9,083 MW in 2025, which represents a 2.0 percent average annual growth rate.

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[16] Id., Section 7.(7)(c), pages 45-46.

[17] Id., Section 7, Tables 7.(4)(a), page 7-37.

[18] Id., Section 7.(7)(c), page 46.

[19] Id., Section 7, Tables 7.(4)(a), page 7-37.

[20] Id., Section 7.(7)(c), page 16.

[21] Energy sales figures are inclusive of KU's operations in Virginia and utility uses and losses.

Winter peak demand is forecast to grow from 6,757 MW in 2011 to 8,376 MW in 2025, which represents a 1.7 percent average annual rate of growth.[22]

KU RESIDENTIAL FORECAST

As previously discussed, the residential forecast is the product of the forecast number of customers and average use per customer which is forecast using a SAE model. It is a function of weather, economic conditions, household demographics, and equipment saturation and usage levels.[23] Residential energy sales are forecast to increase from 6,414 GWh in 2011 to 7,936 GWh in 2025, which represents an average 1.7 percent annual rate of growth.[24]

KU COMMERCIAL FORECAST

The commercial forecast consists of three separate models: General Service, PS-Secondary Schools, and All-Electric Schools. The General Service forecast is the product of the forecast number of customers and average use per customer, which is forecast using a SAE model. The GS customer forecast was tied to the Residential customer forecast because the two groups have historically moved together. However, the GS customer forecast was allowed to grow at a slightly lower rate than the Residential customer forecast. The PS-Secondary forecast includes all customers on the former Large Power Secondary rate. PS-Secondary sales are a function of weather, an Industrial Production Index, the average real price of electricity and binary variables. The Time-of-Day Secondary forecast is based on an allocation of the PS-Secondary forecast. The All-Electric Schools forecast is a function of the number of Residential customers and weather, except for in June, July, and August (summer months), and May, October and November (shoulder months).[25] Commercial energy sales are forecast to increase from 4,635 GWh in 2011 to 5,894 GWh in 2025 representing a 1.9 percent average annual growth rate.[26]

KU INDUSTRIAL FORECAST

The industrial group forecast consists of four separate models: PS Primary, Retail Transmission Service, Industrial Service and Large Time of Day Primary. With the exception of General Service customers in the PS Primary customer class, PS Primary customers take service at primary distribution voltage levels. The forecast is a function of Cooling Degree Days, an industrial production index, the real price of

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[22] Peak demand figures are inclusive of interruptible power and the effects of new and existing DSM programs. Section 7, Tables 7.(4)(a), pages 7-8 and 7-37, and Section 8, Tables 8.(4)(a)-1 and -2, pages 8-80 and 8-81.

[23] LG&E/KU IRP, Section 7.(7)(c), pages 18-19.

[24] Id., Section 7.(4), Table 7.(4)(a), page 7-8.

[25] Id., Section 7.(7)(c), pages 19-20.

[26] Id., Section 7.(4), Table 7.(4)(a), page 7-8.

electricity and various binary variables. The Time of Day Primary forecast is based on historical usage and is taken from the PS Primary forecast. The Retail Transmission Service forecast includes all customers who receive service on a transmission level rate. A separate industrial production index related to mining was included for Mine Power customers. North American Stainless, with its arc furnace, is the only customer on the Industrial Service rate. The forecast for this customer was based on historical usage and direct discussions with the customer. The Large Time of Day Primary class includes all customers on the rate schedule that take service at primary distribution voltage levels. The forecast is a function of an industry weighted industrial production index, the number of households and weather.[27] Taken together, industrial energy sales are forecast to grow from 5,849 GWh in 2011 to 7,613 GWh in 2025 representing a 2.2 percent average annual growth rate.

KU MINE POWER FORECAST

All mine power customers are included in the PS Primary, Large Time of Day Primary or the Retail Transmission Service customer rate classes, depending on usage and voltage.[28]

KU MUNICIPAL FORECAST

The Municipal group (public authorities) forecast contains three separate models: KU Transmission Municipals, KU Primary Municipals and the City of Paris. KU Transmission Municipals take service at transmission voltage levels. This forecast is a function of weather and the number of households in the counties encompassing the various municipalities. The Primary Municipals customers include municipalities taking service at distribution voltage levels. The forecast is a function of weather and the number of households in the counties encompassing the various municipalities. The City of Paris is forecast separately because it generates a portion of its own power. This forecast is a function of weather, the number of households in Bourbon County and binary variables.[29] Energy sales to this class are forecast to grow from 1,587 GWh in 2011 to 1,935 GWh in 2025, which reflects a 1.6 percent average annual growth rate.[30]

KU LIGHTING

KU's lighting forecasts are made using two separate models: KU Street Lighting and KU Private Outdoor Lighting. Each forecast is the product of the number of lighting hours per month and the energy use per fixture per hour, per month. Energy

[27] Id., Section 7.(7)(c), pages 20-21.

[28] Id., page 22.

[29] Id., pages 22-23.

[30] Id., Section 7.(4), Table 7.(4)(a), page 7-8.

use was held to 2008 levels and the number of fixtures was forecast using a trend.[31] Energy sales for lighting are forecast to grow from 84 GWH in 2011 to 99 GWh in 2025.[32]

OLD DOMINION POWER

ODP, KU's affiliate, operates in five counties in Virginia. Forecasts for ODP customer classes are obtained separately and are modeled similarly to KU's customer classes in Kentucky.[33] Energy sales to ODP are forecast to increase from 917 GWh in 2011 to 1,024 GWh in 2025, representing an average annual growth rate of 0.1 percent.

DEMAND SIDE MANAGEMENT

LG&E/KU update forecasts yearly. Such updates capture changes in saturation levels of appliances and equipment in the market and also help capture new emerging energy efficiency technology entering the market and any other DSM programs. The cumulative impacts of all new and existing DSM programs are expected to grow from 389.9 GWh in 2011 to 1,950.7 GWh in 2025. Summer peak reductions from DSM programs are forecast to range from 220 MW in 2011 to 802 MW in 2025. Similarly, winter peak reductions are forecast to range from 46 MW in 2011 to 267 MW in 2025.[34]

SENSITIVITY ANALYSIS

High and low forecast scenarios are based upon probabilistic simulations of the historical volatility of the weather normalized year-over-year energy sales trend. The simulations produce high and low forecasts of energy sales and peak demand approximately 4 percent above and below the base case forecasts.

For LG&E, the 2015 base case energy sales forecast is 13,826 GWh, and the high and low forecasts are 14,316 GWh and 13,3352 GWh, respectively. Similarly, the 2015 peak demand forecast is 2,980 MW, with corresponding high and low forecasts of 3,084 MW and 2,877 MW, respectively. By 2025, the base case energy sales and peak demand are 15,965 GWh and 3,596 MW, respectively. Corresponding high and low bands range from 16,532 GWh–15,397 GWh and 3,716 MW–3,475 MW.[35]

For KU, the 2015 base case energy sales forecast is 24,625 GWh, and the high and low forecasts are 25,559 GWh and 23,692 GWh, respectively. Similarly, the 2015 peak demand forecast is 4,497 MW, with corresponding high and low forecasts of 4,667

[31] Id., Section 7.(7)(c), pages 23.

[32] Id., Section 7.(4), Table 7.(4)(a), page 7-8

[33] Id., Section 7.(7)(c), pages 23-25.

[34] Id., Table 8.(3)(e)(3), pages 8-74 and 8-75, and Table 8.(4)(a)(1), pages 8-80 and 8-81.

[35] Id., Section 7.7e, pages 46-48, and LG&E Tables 7.(7)(e)-1 and 7.(7)(e)-2.

MW and 4,327 MW, respectively. By 2025, the base case energy sales and peak demand are 28,625 GWh and 5,361 MW, respectively. Corresponding high and low bands range from 29,716 GWh–27,535 GWh and 5,560 MW–5,163 MW.[36]

CHANGES FROM LAST IRP FILING

There have been two enhancements to the forecasting process since the last IRP filing. The SAE model is now used to obtain forecasts for General Service customers. The adoption of this model allows the Companies to better incorporate and track end use and energy efficiency enhancements in the commercial sector. The hourly demand forecast methodology has also been enhanced. Previously, each utility's total energy was allocated to specific hours based upon the average 10-year load duration curve. Now, customer-class-specific load profiles are used to develop the hourly demand forecast. This approach more accurately reflects the effects of DSM and energy efficiency programs at the customer class level. Finally, a new residential end use appliance saturation survey was conducted in April 2010. Both Companies participate in an Itron-sponsored Energy Forecaster's Group. This is a collaborative group with other utilities which aids in the development of regional end use saturation and efficiency data for the various customer classes.[37]

INTERVENOR COMMENTS

The Environmental Intervenors, the only party filing comments, contend that the Companies' load growth projections do not include a meaningful sensitivity analysis. Citing the impact of the 2008 recession and the energy efficiency provisions of the Energy Independence and Security Act of 2007 ("EISA") and ARRA, the Environmental Intervenors state, "it would appear that the Companies' estimate of increased annual electricity demand growth as compared to the 2008 IRP is overstated."[38] While noting the sensitivity performed by LG&E/KU for peak demand, the Environmental Intervenors claim the Companies' forecast is lacking in that no sensitivity analysis was performed on the rate of growth for "energy demand."[39]

LG&E/KU REPLY COMMENTS

The Companies state that their load forecasts and sensitivity analysis comply with the requirements in 807 KAR 5:058 and developed their high and low forecasts using historical annual growth rate volatility. LG&E/KU state that the upper and lower uncertainty ranges contained in their sensitivity analysis was developed by moving 1.64 standard deviations from the base case projection each year for both Companies. The

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[36] Id., pages 26-28, and KU Tables 7.7e-1 and 7.(7)(e)-2.

[37] Id., Section 7.(7)(f) and 7.(7)(g), pages 28-29.

[38] Comments of Intervenors Natural Resources Defense Council and Sierra Club on the 2011 Integrated Resource Plan of Kentucky Utilities Company and Louisville Gas and Electric at 3.

[39] Id.

ranges reflect a 90 percent confidence interval over the forecast period, according to the Companies, and constitute a statistically valid representation of the forecast range.[40]

DISCUSSION OF REASONABLENESS/RESPONSE TO 2008 RECOMMENDATIONS

Staff is generally satisfied with LG&E/KU's load forecasting approach, which is both thorough and well documented. The load forecasting model and its results are reasonable, as were LG&E/KU's responses to questions regarding the forecasts. Staff concludes that LG&E/KU provided an adequate explanation of their sensitivity analysis response to the Environmental Intervenors' criticisms of the Companies' load forecasts.

In its report on LG&E/KU's 2008 IRP, Staff made the following recommendations relative to forecasting:

- LG&E/KU should continue to examine and report on the potential impact of increasing competition and future environmental requirements and how these issues are incorporated into future forecasts.

- LG&E/KU should continue efforts to further integrate load forecasting processes and report on these efforts in future IRP filings.

The Companies stated that, due to their obligation to serve in their established service territories in Kentucky and Virginia, the IRP assumed that the status quo will be maintained and that competition will not be mandated. Their planning assumes that the obligation to serve specifically defined service territories will continue. Accordingly, the base IRP forecast does not explicitly incorporate the impacts of increasing competition. The base IRP forecast and the High and Low forecast sensitivities using the SAE models did incorporate future environmental requirements.

LG&E/KU stated that a number of changes in forecasting methodology were incorporated in their 2011 IRP forecasts to further streamline and integrate their forecasting processes. This was done while maintaining or enhancing the consistency of data inputs and the quality of the forecasts.

RECOMMENDATIONS

Staff recommends that LG&E/KU continue to review the potential impact of new and pending environmental requirements and report on how these requirements have been incorporated into their load forecasts and related risk analysis in the next IRP.

Staff also recommends that the Companies' efforts to further refine and integrate their load forecasting process be continued where appropriate and that they report on these efforts in their next IRP.

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[40] Joint Response of Louisville Gas and Electric Company and Kentucky Utilities Company to the Corrected Comments of Intervenors Natural Resources Defense Council and Sierra Club at 3-4.

Staff recommends that LG&E/KU discuss the impact on demand of recent and projected increases in the price of electricity to their customers in the next IRP. The price elasticity of the demand for electricity should be fully examined and a sensitivity analysis performed.

SECTION 3

DEMAND-SIDE MANAGEMENT/ENERGY EFFICIENCY

This section discusses Demand-Side Management/Energy Efficiency ("DSM/EE") aspects of the LG&E/KU IRP. Existing DSM/EE programs offered by LG&E/KU at the time the IRP was filed were approved by the Commission in Case No. 2007-00319.[41] The Commission approved the Companies' proposed seven-year plan at that time to allow sufficient time to implement the selected programs and realize the level of savings that was forecast. Since the approval of that plan, the Companies state that they have learned a great deal about the challenges and obstacles to implementing the programs and achieving the stated targets.[42] Also, as a result of recommendations in the Commission Staff's Report on LG&E/KU's 2008 IRP and the Companies' ongoing review of current DSM/EE programs and research into possible new programs, a plan was developed to expand their portfolio of DSM/EE programs, which was filed with the Commission in 2011.

In Case No. 2011-00134, LG&E/KU requested and were authorized to enhance five existing programs and implement three new programs.[43] They developed the DSM/EE plan proposed in that case in collaboration with their Energy Advisory Group, which seeks opportunities for new and innovative DSM programs for both the residential and commercial customer segments. In conjunction with Case No. 2011-00134, the Companies engaged an independent third-party consultant, ICF International ("ICF"), to provide a broad review of their DSM/EE plan for the period 2011-2017. The review included a detailed overview of the existing programs that the Companies plan to enhance, along with the new programs proposed in Case No. 2011-00134. ICF also conducted a portfolio-level review of the Companies' overall DSM/EE investments. The Companies engaged Navigant Consulting to perform the individual program evaluations within their DSM/EE portfolio.[44]

The programs that were not enhanced as part of the Case No. 2011-00134 filing are still in place and unchanged and continue at their previously approved funding level

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[41] Case No. 2007-00319, The Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company Demand Side Management for the Review, Modification, and Continuation of Energy Efficiency Programs and DSM Cost Recovery Mechanisms (Ky. PSC March 31, 2008).

[42] Response to Item 5 of Commission Staff's First Data Request ("Staff's First Request").

[43] Case No. 2011-00134, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company (Ky. PSC Nov. 9, 2011).

[44] Response to Item 26 of Staff's First Request.

through 2014. Upon full implementation of the DSM/EE portfolio, the Companies expect to achieve a 500 MW reduction in summer peak demand and a 143.9 MW reduction in winter peak demand by the end of 2017.[45] The corresponding energy reduction for 2017 is 1,181.2 GWh. By 2026, LG&E/KU expect to achieve 838.7 and 279.4 MW summer and winter coincident peak reductions, respectively, and a total energy reduction of 2046.6 GWh.[46]

EXISTING DSM/EE PROGAM DESCRIPTIONS

LG&E/KU identified three current residential or commercial programs approved in Case No. 2007-00319 that will remain unchanged. These programs were not included in the new DSM/EE plan filed in Case No. 2011-00134. LG&E/KU propose to continue these programs, which they characterize as "market transformation programs" through 2014. These three programs are currently operating satisfactorily within the approved program designs, and, according to the Companies, do not warrant enhancements at this time.[47] These programs, as described by the Companies, are as follows:

1. Residential High Efficiency Lighting – This program promotes increased use of ENERGY STAR rated Compact Fluorescent Lights ("CFL") within the residential sector of LG&E and KU electric consumers. The program distributes CFL bulbs through direct-mail delivery, customer walk-in centers and retailer coupons.

2. Residential New Construction – This program is designed to reduce residential energy use and facilitate market transformation by creating a shift in builders' new home construction to include energy efficient construction practices.

3. Residential and Commercial HVAC Diagnostics and Tune-up Program – This program targets customers with probable heating, ventilation, and air conditioning ("HVAC") system performance issues.[48]

In addition to the programs identified above, LG&E/KU have two additional programs designed to educate and assist customers in the general area of DSM/EE programs. They are as follows:

4. Customer Education and Public Information – This program's objective is to increase public awareness and understanding of the urgent need for more efficient use of energy, and the environmental and financial impacts created by climate change issues. This program will also increase customer awareness and encourage utilization of energy efficiency products and services. Participation is voluntary and LG&E/KU

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[45] LG&E/KU IRP, pages 5-40 and 8-75.

[46] Id., pages 8-75 and 8-76.

[47] Id., pages 5-41 and 8-75.

[48] Residential and Commercial HVAC Diagnostics and Tune-up Program is shown as one program in Case No. 2011-00134. In the IRP, this is shown as two separate programs, the Residential HVAC Diagnostics and Tune-up Program and the Commercial HVAC Diagnostics and Tune-up Program.

cannot compel customer participation in DSM/EE programs; however, Staff shares the Commission's belief that most well-informed customers would choose to participate as a means to avoid higher energy bills. Staff hopes the Companies will use this program to the fullest to educate customers on the need for greater energy efficiency.

5. Dealer Referral Network – The program is a web-based Dealer Referral Network designed to deliver the following services to program constituents:

- Assist customers in finding qualified and reliable personnel to install energy efficiency improvements recommended and/or subsidized by the various energy efficiency programs;
- Identify energy-related subcontractors for contractors seeking to build energy-efficient homes or improve energy efficiency of existing homes; and
- Fulfillment of incentives and rebates.

ENHANCED DSM/EE PROGRAMS

In Case No. 2011-00134, the Companies received approval to offer through 2017, with enhancements, the five residential and commercial DSM programs that were authorized in Case No. 2007-00319. The programs are as follows:

1. Residential and Commercial Load Management/Demand Conservation – This program cycles residential and commercial central air conditioning units and water heaters, and residential pool pumps. It is designed to provide customers an incentive to allow the Companies to interrupt service to their central air conditioners, water heaters and/or pool pumps at peak demand periods when additional resources are needed to meet customer demand. The enhancement approved in Case No. 2011-00134 will allow for increased incentives in order to encourage greater customer enrollment.

2. Residential Conservation/Home Energy Performance – This program targets customers who occupy single-family homes, apartments, or condominiums. It provides customers an on-site energy audit that identifies opportunities for improved energy efficiency. The enhancement approved in Case No. 2011-00134 is to include incentives to implement the energy retrofit measures recommended though the energy audit process allowing for greater energy and demand reductions.

3. Residential Low Income Weatherization – This program is designed to reduce the energy bills of low-income customers by weatherizing their homes. This program is available to customers who qualify for Low Income Home Energy Assistance Program ("LIHEAP") services. The enhancement approved in Case No. 2011-00134 will allow for increased weatherization measures for the low-income customer segment and for an increase in the number of customers served.

4. Commercial Conservation/Commercial Incentives – The objective of this program, which is offered to all commercial customers, is to identify energy efficiency opportunities for customers and assist them in the implementation of those identified energy efficiency opportunities. The enhancement approved in Case No. 2011-00134

created a custom rebate option to allow for additional opportunities to capture savings beyond those from the original prescriptive equipment list. This rebate is intended to encourage greater customer enrollment in the program.

5. Program Development and Administration – This program was established to capture costs incurred in the development and administration of energy efficiency programs where it is difficult to assign costs specifically to an individual program. This program currently employs three full-time equivalents ("FTE"), and the Companies were approved to add three more FTE positions in Case No. 2011-00134. These positions are for procurement, marketing, and a financial analyst.

NEW DSM/EE PROGRAMS

LG&E/KU sought and received approval in Case No. 2011-00134 for three new DSM/EE programs to operate through 2017. The new programs are the (1) Residential Smart Energy Profile Program, (2) Residential Incentive Program, and (3) Residential Refrigerator Removal Program. These programs were selected based on the screening process identified in Case No. 2007-00319. This process included a qualitative test and a subsequent two-phase quantitative test. The present value for each program was calculated using four of the generally recognized "California Tests". Following are the program descriptions:

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

2. Residential Incentives – The objective of this program is to encourage customers to purchase various Energy Star appliances, HVAC equipment, or window films that meet certain requirements, qualifying them for incentives. This program will be open to all residential customers. The Companies are planning on one and one-half FTE positions to administer this program.

3. Residential Refrigerator Removal – This program is designed to provide removal and recycling of inefficient secondary refrigerators and freezers from LG&E/KU customer households. The removal of these inefficient units will reduce consumption and demand.

RESPONSIVE PRICING AND SMART METERING PILOT PROGRAM

In Case No. 2007-00117,[49] the Commission approved LG&E's application to develop a responsive pricing and smart metering pilot program that would serve up to

[49] Case No. 2007-00117, Application of Louisville Gas and Electric Company for an Order Approving a Responsive Pricing and Smart Metering Pilot Program (Ky. PSC July 12, 2007).

2,000 customers for an initial three-year term from January 2008 to January 2011. LG&E filed with the Commission a tariff establishing Residential and General Service Responsive Pricing that incorporates a time-of-use rate with critical peak pricing ("CPP"). The Responsive Pricing tariff became effective January 2008. Pursuant to the Commission's Order, the pilot program continues and the rates and cost-recovery remain in effect. On July 1, 2011, LG&E filed an evaluation on the results obtained from the three-year study period.

During the pilot, a customer-behavior analysis measured two key components. The evaluation's Executive Summary states, "analysis on customer behavior has been performed to measure two key components: (1) the actual energy shift and change in customer behavior patterns, and (2) how time-of-use rates and various devices effected *(sic)* customer satisfaction. Pilot results showed high-quality load reductions for demand response, with load found to shift from higher-priced weekday hours to lower-priced off-peak and weekend time periods. Additionally, customers using in-home devices but not on the time-of-use rates were found to be using almost half of their energy during the low tier of the rate schedule. Customers who received critical peak pricing ("CPP") signals shifted their energy use but created a 0.5 – 0.8 kW per customer higher peak than the original system peak and consumed more overall energy."

There are only approximately 80 customers remaining on the Responsive Pricing rate, and LG&E recommends the Commission issue an order discontinuing the pilot program. But, in the evaluation, LG&E states it had gained valuable insight through this pilot program. The Executive Summary of the evaluation further states, "operationally LG&E has gained valuable experience in recognizing the risks of emerging technologies in smart metering and advanced two-way communications. LG&E seeks to consider developing further experience and methods for deploying these technologies through additional pilots and trials designed to test customer acceptance, use, and cost to benefit analysis. For example, capability to automatically capture, upload, and validate data is vital to providing customers with access to their consumption trends and associated costs, and evaluating consumer willingness and ability to conserve energy. Furthermore, such systems could enable LG&E to provide customers with access to their data through a variety of virtual based tools thus enhancing the customer value and maintaining continued customer satisfaction. Piloting these solutions would be of critical benefit to LG&E as their societal value is showing to be very important to broader smart meter activities."

From this three-year pilot, LG&E made observations in the evaluation report. One observation is that network performance can be largely dependent on terrain topography. Natural barriers such as foliage and the distance between the meters and backhaul communication equipment in remote areas of the service territory are crucial variables that require further evaluation. Additional pilot programs would provide LG&E with an opportunity to exercise new and emerging technologies in metering and network communications, which could help overcome geography-specific barriers. A second observation is that LG&E gained significant knowledge about customer consumption, rebound of energy usage following or in anticipation of price reductions after peak pricing, and energy efficiency achieved by some customers, though only providing information through in-home displays. LG&E suggests that a high level of guidance and direction be provided through additional pilot programs. LG&E believes that providing customers with technologies and detailed usage information, coupled with education, will empower customers to make decisions about their personal energy consumption. Customer education is required if demand response and variable rate structures are to be expanded. A third observation is that LG&E was not able to utilize and evaluate fully computerized meter data management system capabilities, given that such systems were not readily available and economically feasible during the pilot deployment. These systems exist today, however, and are scalable enough to handle trials and pilots at a fraction of the cost of a fully implemented system. LG&E believes that pilots and trials designed to understand customer behavior and investigate emerging the integration of technologies into existing system infrastructure should be continued. LG&E recognizes that customer education about the benefits of energy efficiency and specifically smart technology is crucial to increased and ongoing consumer acceptance and employment of the technology.

GREEN ENERGY

The Companies each have green energy tariffs. These tariffs allow customers to voluntarily purchase Renewable Energy Certificates ("REC"). A REC represents the beneficial environmental attributes of energy generated absent the greenhouse gas emissions associated with 1 MWh. Energy generated using renewable resources can include wind, solar, and hydro power.

Both Companies have Small Green Energy ("SGE") Riders, Tariff SGE, which are available to residential and small-business customers under the RS and GS tariffs. Customers can purchase RECs in monthly increments of 300 kWh for $5 per month. The commitment of residential and small commercial customers to purchase RECs can be cancelled at any time. Also, the Companies have Large Green Energy ("LGE") Riders, Tariff LGE, for all other customers. Customers can purchase RECs in monthly increments of 1,000 kWh for $13 per month. Large commercial and industrial customers must commit for one year.

For the period July 1, 2011 through December 31, 2011, LG&E had 994 customers on Tariff SGE and purchased 39,355 RECs for 2011. It had no customers on Tariff LGE. For the same time period, KU had 572 customers on Tariff SGE and purchased 24,215 RECs. KU also had three customers on Tariff LGE who purchased 786 RECs. The Companies purchase RECs in-house. The Companies state they have not seen a drop in participation following recent rate cases, but in order to mitigate this risk, the Companies continue to maintain program promotion efforts.[50]

[50] Response to Item 9 of Staff's First Request.

SUMMARY DISCUSSION OF DSM/EE

Staff recognizes the Companies' efforts since the last IRP to implement the programs approved in Case No. 2007-00319 and in researching and developing the enhanced and new programs approved in Case No. 2011-00134. While initial results from the DSM/EE programs approved in the former case were not as great as expected, due to obstacles and challenges involved in implementing the programs, the Companies were able to exceed the full portfolio's projected peak demand and energy savings in 2010. The lessons learned in implementing programs approved in Case No. 2007-00319 will aid the Companies in promoting best practices and broad targeting of programs approved in Case No. 2011-00134. Staff commends the Companies efforts to follow the recommendations from the 2008 IRP Staff Report and the steps they have taken in enhancing existing programs and developing new programs.

INTERVENOR COMMENTS

The Environmental Intervenors maintain that the Companies "need to enhance the DSM/EE programs so as to more fully capture all cost-effective means for reducing demand growth." While giving credit to the programs approved in Case No. 2011-00134, they claim that experience throughout the country shows that well-designed and implemented DSM/EE programs can reduce energy demand by 1 to 2 percent per year at a significantly lower cost than it takes to produce that same amount of energy. Further, they claim that the Companies' own filings of DSM/EE net benefits and the Program Review by ICF indicate that far more demand reductions can cost-effectively be achieved.[51] The Environmental Intervenors contend that the Companies' benefit-cost ratio for the entire DSM/EE portfolio suggests there is a great deal of additional energy savings that could be achieved through programs with a positive benefit-cost ratio. Based upon the ICF Program Review and the extent to which the results of the Utility Cost Test and Total Resource Cost Test exceed 1.0, they claim there is significant opportunity to cost-effectively increase the DSM/EE incentives offered in order to increase participation in energy saving programs and go after much deeper energy savings, while remaining cost-effective and delivering net benefits to the Companies' service territories.

The Environmental Intervenors also maintain the Companies should evaluate the level of DSM programs by allowing DSM/EE programs to compete with supply-side resources on equal footing in any energy planning modeling undertaken by the Companies. They also suggest the Commission should follow ICF's recommendation to conduct an energy efficiency potential study, which would help the Companies determine how much energy efficiency is available in their service territories and at what cost. The Environmental Intervenors recommend that the Companies double their

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[51] ICF International, Louisville Gas and Electric Company/Kentucky Utilities Company – DSM Program Review (Mar. 18, 2011). The ICF Report was filed as Exhibit 10 to the Companies' Demand Side Management and Energy Efficiency Program Plan filing in Case No. 2011-00134.

DSM-related energy savings to 1 percent of sales for each of the next three years, and to increase the level to 2 percent per year thereafter.

LG&E/KU REPLY COMMENTS

The Companies maintain they have been aggressive in their DSM/EE efforts, as evidenced by the enhanced and new programs approved by the Commission in Case No. 2011-00134, and their continuing efforts to review and analyze new opportunities for energy efficiency. While the Companies did not specifically address the Environmental Intervenors' suggestion to follow the ICF recommendation and conduct an energy efficiency potential study, they stated that it is unlikely that any currently cost-effective DSM/EE programs have been overlooked, thereby eliminating the need to conduct a new potential study.

The Companies think that one of the reasons the Environmental Groups may believe there are cost-effective DSM/EE programs that have been overlooked is that the Environmental Intervenors largely dismiss the Ratepayer Impact Measure ("RIM") cost-benefit test. The Companies state it would be easy to achieve additional energy and demand savings if the cost to non-participants were no object, but the Companies take the RIM test seriously and attempt to make their portfolio of DSM/EE programs cost-effective for all customers, both participants and non-participants.

The Companies maintain that if the Environmental Intervenors had performed savings calculations for residential and commercial customers only, which are the only customers that have DSM/EE programs, the amount of demand and energy savings would be approximately 1 percent of sales. This is significantly more than what the Environmental Intervenors estimated by comparing the Companies' energy and demand savings to total sales.

Finally, the Companies state that the Environmental Intervenors have overlooked some unavoidable facts concerning their DSM/EE programs and the overall prospects of DSM/EE in Kentucky that affect demand and energy savings. First, the Companies in particular, and Kentucky's electric utilities more broadly, have some of the lowest rates in the nation, decreasing the financial incentive for customers to conserve. Second, as the Commonwealth of Kentucky has established no demand or energy savings requirements, it is unreasonable for the Environmental Intervenors to compare the Companies' DSM/EE demand and energy savings to the savings utilities are achieving in states that have such legislative or regulatory requirements.

The Companies state their belief that, overall, their existing DSM/EE portfolio is robust and not lacking in any respect. LG&E/KU state that they will continue to monitor opportunities for expanded and new DSM/EE programs as such opportunities arise, and that they will strive to achieve the energy savings goals promulgated in the governor's energy plan for Kentucky.

DISCUSSION OF REASONABLENESS/RESPONSE TO 2008 RECOMMENDATIONS

In its report on LG&E/KU's 2008 IRP, Staff made the following recommendations relative to DSM/EE:

- Pursue DSM/EE alternatives with industrial and large commercial customers.

- Continue aggressively seeking opportunities for new and innovative DSM/EE programs.

- Work to verify (to the extent possible) the actual achieved reduction in energy usage of each of the pilot DSM programs.

Staff notes that the Companies filed their application in Case No. 2011-00134 on April 14, 2011, one week before filing their IRP. A final order was issued in that case on November 9, 2011 approving the six enhanced programs as well as three new programs, through 2017 with the requirement that the Companies file a three-year review report in 2014.

The commercial programs approved in Case No. 2011-00134 are responsive to the increasing number of requests the Companies have received from the commercial customer segment. The commercial programs include additional energy efficiency retrofits eligible for incentives, such as refrigeration, and new commercial customized incentives to encourage sustained energy efficient retrofits for customers that are not covered by the existing Commercial Conservation/Incentive Program. The Companies continue to review and evaluate existing and potential new residential and commercial DSM/EE programs for future expansion filings.

The Companies' analysis of potential DSM options in Case No. 2011-00134 was performed using the DSMore program, which replaced DSManager for providing benefit-cost calculations for DSM/EE programs. The benefit-cost calculations contained in DSMore provide more robust analytics surrounding weather and market conditions and a more transparent platform to understand the underlying calculations associated with the benefit-cost tests. In addition, in the current IRP, the Companies used class-specific load profiles to develop hourly demand forecasts. This approach enabled them to better reflect DSM/EE programs that impact the load profile of specific classes. Together, these changes have allowed the Companies to more closely measure the actual achieved reduction in energy usage for the DSM/EE programs in existence, as well as those reductions that will be achieved in the enhanced and new programs approved in Case No. 2011-00134.

RECOMMENDATIONS

The Environmental Intervenors recommendation that the Commission require that LG&E/KU perform a potential or market characterization study has already been addressed. In Case No 2011-00375,[52] the Commission directed the Companies to commission a potential or market characterization study as recommended in the ICF report.

In its July 1, 2012 Responsive Pricing and Smart Metering Pilot Program Final Report, LG&E seeks to develop internal capabilities to deal with changing smart meter technology and its integration into LG&E's existing system infrastructure prior to large or full-scale deployment meters. LG&E has five goals for additional pilots. Those goals are: (1) develop a further understanding of customer perspectives of smart meter technology; (2) develop a further understanding of how selected meter data management systems will interface with LG&E's current IT infrastructure; (3) develop an understanding of the progressive change in metering, communications, and data management technologies over time, ongoing quality control and potential interoperability, implementation, and standard issues; (4) develop an understanding and experience of multiple rate offerings by providing customers with optional rate choices, rate comparison tools, and access to energy usage data; and (5) develop experience and techniques for deploying smart meter technologies and communications systems in rural areas and evaluate convergence of such infrastructure with existing load control programs to ensure a sustainable demand response solution. The Staff encourages the pursuit of these goals in the integration of smart meter technology into LG&E's existing system infrastructure.

The Staff encourages the Companies to continue to review new possible DSM/EE programs and seek ways to expand the current approved DSM/EE plan.

The Staff recommends that the Companies continue to educate customers and to promote the availability of and participation in DSM/EE programs. Such participation represents one way in which customers can impact the degree to which ever-increasing energy costs impact their electric bills.

The Staff recommends that the Companies continue to define and improve procedures to evaluate, measure, and verify both actual costs and benefits of energy savings based on the actual dollar savings and energy savings.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

INTRODUCTION

This section summarizes, reviews, and comments on LG&E/KU's evaluation of their existing supply-side resources and potential future supply-side resources. It also

[52] Case No. 2011-00375, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity 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 La Grange, Kentucky (Ky. PSC May 3, 2012)

includes discussion on various aspects of the Companies' environmental compliance planning.

EXISTING CAPACITY

The Companies are generation, transmission, and distribution utilities operating as a single interconnected and centrally dispatched electric system. LG&E/KU coordinate planning, construction, operation and maintenance of their facilities. They serve approximately 939,000 electric customers via a transmission and distribution network consisting of 27,600 miles. At present, LG&E/KU have a joint net summer generation capacity of 8,001 MW. LG&E provides electric service in an area covering approximately 700 square miles and includes the Louisville metropolitan area and 17 surrounding counties. KU supplies electric service in an area that covers approximately 6,600 non-contiguous square miles and includes 77 counties in Kentucky. KU sells wholesale electricity for resale to 12 municipalities in Kentucky and serves five counties in Virginia. It also serves five customers in Tennessee.

LG&E/KU's power generating system consists of 19 coal-fired units operated at seven different generating stations: Cane Run, E.W. Brown, Ghent, Green River, Mill Creek, Trimble County and Tyrone. These units combined have a net summer rating of 5,808 MW. The LG&E/KU system also includes 16 gas-fired combustion turbines which supplement the Companies' coal-fired base load units during periods of peak demand. These facilities are located at the Cane Run, E.W. Brown, Haefling, Paddy's Run, Trimble County, and Zorn generating stations and have a combined net summer rating of 2,115 MW. LG&E and KU also have hydroelectric facilities located at Dix Dam and Ohio Falls which have a combined summer rating of 78 MW. The Companies also have access to 155 MW of capacity and the associated energy at the time of summer peak from their ownership interests in the Ohio Valley Electric Corporation ("OVEC").

The largest and most recently completed coal-fired unit is Trimble County Unit 2. It has a net summer rating of 732 MW and was placed in service in early 2011. The Companies own 75 percent of both this unit and Trimble County Unit 1. The other 25 percent of each unit is owned by the Illinois and Indiana municipal power associations. Table 1 below presents a summary of both LG&E/KU's existing and potential future generating units.

TABLE 1

EXISTING and FUTURE GENERATION

Plant Name	Unit No.	Location / Status	In Serv Date	Unit Type	Net Capability (MW) 2011/12 Winter	Net Capability (MW) 2011 Summer	Entitlement (%) KU	Entitlement (%) LGE	Fuel	Fuel Storage Cap SO_2 Content	Scheduled Upgrades Derates, Retirements
Cane Run	4	Louisville / Existing	1962	Steam	155	155		100	Coal	350,000 Tons (6.0# SO_2)	Assumed to retire 2016
	5		1966		168	168					
	6		1969		240	240					
	11		1968	Turbine	14	14			Gas/ Oil	50,000 Gals	None
Dix Dam	1-3	Burgin / Existing	1925	Hydro	28	26	100		H_2O	None	4 MW upgrade 2011-2012
E. W. Brown Coal	1	Burgin / Existing	1957	Steam	107	106	100		Coal	360,000 Tons (6# SO_2)	Baghouse Derate 2014
	2		1963		168	166					Baghouse Derate 2015
	3		1971		415	411					SCR Derate 2012 Baghouse Derate 2016
E.W. Brown	5		2001	Turbine	131	122	47	53	Gas	2,200,000 Gals	None
E.W. Brown	6		1999		163	146	62	38	Gas/ Oil		
	7		1999		163	146					
E.W. Brown	8		1995		129	121	100				
	9		1994		129	121					
	10		1995		129	121					
	11		1996		129	121					
Ghent	1	Ghent / Existing	1974	Steam	486	493	100		Coal	1,300,000 Tons (6# SO_2)	Baghouse Derate 2016
	2		1977		480	490					Baghouse Derate 2016
	3		1981		485	454					Baghouse Derate 2015
	4		1984		495	487					Baghouse Derate 2015
Green River	3	Central City / Existing	1954	Steam	71	68	100		Coal	150,000 Tons (4.5 of SO_2)	Assumed to Retire 2016
	4		1959		102	95					
Haefling	1	Lexington / Existing	1970	Turbine	14	12	100		Gas/ Oil	130,000 Gals	None
	2		1970		14	12					
	3		1970		14	12					
Mill Creek	1	Louisville / Existing	1972	Steam	303	303		100	Coal	1,000,000 Tons (6# SO_2)	Baghouse Derate 2014
	2		1974		299	301					Baghouse Derate 2013
	3		1978		397	391					Baghouse Derate 2015
	4		1982		492	477					Baghouse Derate 2014
Ohio Falls	1-8	Louisville / Existing	1928	Hydro	Run of River (35/52)			100	H_2O	None	12 MW upgrade 2011-2014
Paddy's Run	11	Louisville / Existing	1968	Turbine	13	12		100	Gas	None	None
	12		1968		28	23					
Paddy's Run	13		2001		175	158	47	53			
Tyrone	3	Versailles / Existing	1953	Steam	73	71	100		Coal	30,000 Tons (1.4# SO_2)	Assumed to Retire 2016
Trimble County Coal (75%)	1	Near Bedford / Existing	1990	Steam	515 (386)	511 (383)	0	75	Coal	1,000,000 Tons (6# SO_2)	Baghouse Derate 2015
	2		2011		761 (571)	732 (549)	61	14		150,000 Tons (0.6# SO_2)	None
Trimble County	5		2002	Turbine	180	160	71	29	Gas	None	None
	6		2002		180	160					
	7		2004		180	160	63	37			
	8		2004		180	160					
	9		2004		180	160					
	10		2004		180	160					
Zorn	1	Louisville / Existing	1969	Turbine	16	14		100	Gas	None	None
Future Units											
3x1 CC	1	Unknown / Proposed	2016	Turbine	1009	907	Unknown		Gas	None	None
3x1 CC	2		2018		1009	907					
3x1 CC	3		2025		1009	907					

RELIABILITY CRITERIA

LG&E/KU indicate that their strategy is to furnish electric energy services in a reliable, economic, and efficient manner. For reliability purposes, a reserve margin is needed to have sufficient capacity available to allow for (1) unexpected loss of generation; (2) reduced generation capacity due to equipment problems; (3) unanticipated load growth; (4) variances in load due to extreme weather conditions; and (5) disruptions in contracted purchased power. A utility's required reserve capacity can be supplied via its own generation, purchased power, or a combination thereof. "Reserve margin" is derived as follows:

Reserve Margin = (Total Supply Capability- Peak Load)/ Peak Load

LG&E/KU commissioned a study to determine an optimal reserve margin that was performed by Astrape Consulting in April 2011.[53] The study relied on the Strategic Energy and Risk Valuation Model ("SERVM")[54] to model factors including load growth, weather uncertainty, unit performance, and the capability to import from interconnected regions. The model evaluated "reliability energy costs" associated with 1) Unserved Energy Events, 2) Expensive (i.e., above Combustion Turbine dispatch cost) Purchased Power and 3) Dispatching Expensive Peaking Resources. Thousands of scenarios were considered with various reserve margin levels ranging from 10 to 24 percent compared to the costs of carrying reserves. The optimum reserve margin is established when the reliability energy costs combined with the costs of carrying reserves are minimized. Due to the high volatility of reliability costs and the fixed costs of reserve capacity, LG&E/KU identified the best risk assessment to be at the 85th percentile (confidence level) of reliability energy costs. Given the model inputs and the risk assumption, total reliability costs were minimized at a reserve margin of 15.5 percent.[55]

Per the study, LG&E/KU identified an optimal target reserve margin in a 15 to 17 percent range. For planning purposes, LG&E/KU targeted a 16 percent reserve margin which would provide an adequate and reliable system to meet customers' demands.

SUPPLY-SIDE EVALUATION

Fifty-six mature and emerging technology alternatives were screened through a levelized screening analysis developed by utilizing the Electric Power Research Institute Technical Assessment Guide ("EPRI TAG") and the Cummins & Barnard Report.[56] The EPRI TAG was used for the mature and developed technologies, and the Cummins & Barnard Report was for some experimental technologies.[57] Total costs were calculated

[53] LG&E/KU IRP, Volume III, LG&E and KU 2011 Reserve Margin Study, Appendix A.

[54] Id., page 2, Strategic Energy and Risk Valuation Model (SERVM).

[55] Id., page 6, Figure ES3.

[56] *The Cummins and Barnard Generation Options Technology Study*, dated December 2007.

[57] LG&E/KU IRP, Section 8, page 8-89.

for each alternative, at various levels of utilization, over a 30-year period and levelized to reflect uniform payment streams in each year. Levelized costs of each alternative, at varying capacity factors, are compared and the least-cost technologies for capacity factor increments throughout the planning period are determined. The screening analysis considers three sensitivity variables: capital cost, operating efficiency (measured by heat rate), and fuel cost.

Environmental costs pertaining to NO_x and SO_2 are included in the analysis. The environmental cost implications regarding NO_x and SO_2 emissions are accounted for as a variable cost similar to a fuel adder.[58] LG&E/KU indicate that no environmental cost has been included for CO_2 since there is no market anticipated for CO_2 emissions allowances, due to currently proposed regulations.[59] LG&E/KU notes that in December 2010, the Environmental Protection Agency ("EPA") announced a plan to propose new source performance standards ("NSPS") regulations for greenhouse gas and/or CO_2 emissions.[60] The new rules would be applicable to new and modified electric generating units ("EGU") and would set guidelines for existing EGUs. As of the date of the LG&E/KU filing of this IRP, the EPA had not released the final NSPS.[61] LG&E/KU further state that until more information is provided, the potential impact of the new rules is uncertain and they will continue to review the issue.[62]

Table 2 shows the technologies included in the LG&E/KU screening analysis.

TABLE 2
TECHNOLOGIES SCREENED

ID	Technology Description	Category	Sub-Category	Fuel Type
1	Pumped Hydro Energy Storage	Storage	Pumped Hydro	Charging Only
2	Advanced Battery Energy Storage	Storage	Battery	Charging Only
3	Compressed Air Energy Storage	Storage	Compressed Air	Gas and Charging
4	Simple Cycle GE LM6000 CT	Natural Gas	SCCT	Gas
5	Simple Cycle GE 7EA CT	Natural Gas	SCCT	Gas
6	Simple Cycle GE 7FA CT	Natural Gas	SCCT	Gas
7	Combined Cycle GE 7EA CT	Natural Gas	CCCT	Gas
8	Combined Cycle 1x1 7F-Class	Natural Gas	CCCT	Gas
9	Combined Cycle 1x1 G-Class CT	Natural Gas	CCCT	Gas
10	Combined Cycle 2x1 7F-Class CT	Natural Gas	CCCT	Gas
11	Combined Cycle 3x1 7F-Class CT	Natural Gas	CCCT	Gas

[58] Id., page 8-104.

[59] LG&E/KU IRP, Volume III, Analysis of Supply-Side Technology Alternatives, Prepared by Generation Planning and Analysis, March 2011, at 1.

[60] LG&E/KU IRP, Section 8, page 8-104.

[61] On March 27, 2012, EPA released a proposal to set a standard for CO_2 emissions from new fossil fuel EGUs, which would subject them to a maximum emissions rate of 1,000 pounds per MWh. The proposal would not apply to existing EGUs or to modification or reconstruction of existing EGUs. Also, the standards would not apply to new coal-fired EGUs that had already received preconstruction permits and begin construction within 12 months of the date the proposal is published in the Federal Register.

[62] LG&E/KU IRP, Section 8, page 8-104.

ID	Technology Description	Category	Sub-Category	Fuel Type
12	Combined Cycle Seimens 5000F CT	Natural Gas	CCCT	Gas
13	Humid Air Turbine Cycle CT	Natural Gas	CCCT	Gas
14	Kalina Cycle CC CT	Natural Gas	CCCT	Gas
15	Cheng Cycle CT	Natural Gas	CCCT	Gas
16	Peaking Microturbine	Natural Gas	CT	Gas
17	Baseload Microturbine	Natural Gas	CT	Gas
18	Subcritical Pulverized Coal 256 MW	Coal	Pulverized Coal	Coal
19	Subcritical Pulverized Coal 512 MW	Coal	Pulverized Coal	Coal
20	Circulating Fluidized Bed 2x 250 MW	Coal	Fluidized Bed Combustion	Coal
21	Supercritical Pulverized Coal 565 MW	Coal	Pulverized Coal	Coal
22	Supercritical Pulverized Coal 800 MW	Coal	Pulverized Coal	Coal
23	Pressurized Fluidized Bed Combustion	Coal	Fluidized Bed Combustion	Coal
24	1x1 IGCC	Coal	IGCC	Coal Gasification
25	2x1 IGCC	Coal	IGCC	Coal Gasification
26	Subcritical Pulverized Coal 502 MW CCS	Coal	Pulverized Coal	Coal
27	Circulating Fluidized Bed CC	Coal	Fluidized Bed Combustion	Coal
28	Supercritical Pulverized Coal 565 MW CCS	Coal	Pulverized Coal	Coal
29	Supercritical Pulverized Coal 800 MW CCS	Coal	Pulverized Coal	Coal
30	1x1 IGCC CCS	Coal	IGCC	Coal Gasification
31	2x1 IGCC CC	Coal	IGCC	Coal Gasification
32	Wind Energy Conversion	Renewable	Wind	No Fuel
33	Solar Photovoltaic	Renewable	Solar	No Fuel
34	Solar Thermal, Parabolic Trough	Renewable	Solar	No Fuel
35	Solar Thermal, Power Tower w/Storage	Renewable	Solar	No Fuel
36	Solar Thermal, Parabolic Dish	Renewable	Solar	No Fuel
37	Solar Thermal, Central Receiver	Renewable	Solar	No Fuel
38	Solar Thermal, Solar Chimney	Renewable	Solar	No Fuel
39	MSW Mass Burn	Waste to Energy	MSW	MSW
40	RDF Stoker-Fired	Waste to Energy	RDF	RDF
41	Wood-Fired Stoker Plant	Waste to Energy	Biomass	Biomass
42	Landfill Gas IC Engine	Waste to Energy	LFG	Landfill Gas
43	TDF Multi-Fuel CFB (10% Co-Fire)	Waste to Energy	TDF	10% TDF/90% Coal
44	Sewage Sludge & Anaerobic Digestion	Waste to Energy	SS	Sewage
45	Bio Mass (Co-Fire)	Waste to Energy	Biomass	10% Renew/90% Coal
46	Wood-Fired CFBC	Waste to Energy	Fluidized Bed Combustion	Biomass
47	Co-Fired CFBC	Waste to Energy	Fluidized Bed Combustion	10% Renew/90% Coal
48	Molten Carbonate Fuel Cell	Natural Gas	Fuel Cell	Gas
49	Solid Oxide Fuel Cell	Natural Gas	Fuel Cell	Gas
50	Spark Ignition Engine	Natural Gas	Reciprocating Engine	Gas
51	Hydroelectric New 30MW	Renewable	Hydro	No Fuel
52	Hydroelectric 50 MW Bulb Unit	Renewable	Hydro	No Fuel
53	Hydroelectric 14 MW Kaplan Units	Renewable	Hydro	No Fuel
54	Hydroelectric 25 MW Bulb Units	Renewable	Hydro	No Fuel
55	Hydroelectric 50 MW Kaplan Unit	Renewable	Hydro	No Fuel
56	Hydroelectric 50 MW Propeller Unit	Renewable	Hydro	No Fuel

Based on the results of the screening analysis, the technologies listed in Table 3 were recommended for further analysis in the resource optimization studies using Strategist.[63]

TABLE 3

TECHNOLOGIES SUGGESTED FOR ANALYSIS WITHIN STRAGETIST

- Supercritical Pulverized Coal Unit – 800 MW
- Combined Cycle 3 x 1 F-Class Combustion Turbine
- Combined Cycle 2 x 1 F-Class Combustion Turbine
- Combined Cycle 1 x 1 G-Class Combustion Turbine
- Simple Cycle GE 7FA Combustion Turbine
- Landfill Gas IC Engine
- Wind Energy Conversion
- Ohio Falls 50 MW Bulb Hydro Unit

LG&E/KU indicate that the optimal plan is the installation of three 3 x 1 Combine Cycle units: one in each of the years 2016, 2018, and 2025. The Companies filed an application on September 15, 2011, which was docketed as Case Number 2011-00375, in which they sought approval to add a 640 MW natural gas combined cycle combustion turbine at LG&E's Cane Run Generating Station and to purchase natural gas simple cycle generation facilities in La Grange, Kentucky, from Bluegrass Generation Company, LLC ("Bluegrass Generation") which includes three turbines with a combined capacity of 495 MW to replace the retired generation at Cane Run, Green River, and Tyrone.

On May 3, 2012 the Commission found the proposed facilities are needed and granted LG&E/KU a Certificate of Public Convenience and Necessity for the proposed facilities. On June 18, 2012 LG&E/KU notified the Commission by letter that they had decided not to proceed with the Bluegrass Generation acquisition because the FERC's order required the Companies to submit a market power mitigation proposal by July 3, 2012 which FERC would have to review and then decide whether to accept or reject.[64] The FERC order would also require LG&E/KU to file a second compliance filing no later than December 31, 2016 to re-examine market power issues related to the Bluegrass Generation units.[65]

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[63] Strategist is a proprietary, widely used software package from Ventyx used to evaluate resource options. Strategist integrates the supply-side, demand-side, and environmental compliance alternatives to produce a ranked number of plans that meet the prescribed reliability criteria.

[64] LG&E/KU letter filed in Case No. 2011-00375, received June 18, 2012.

[65] On June 27, 2012, representatives of LG&E/KU met with representatives of the AG and Commission Staff to provide further updates on the Bluegrass Generation purchase. LG&E/KU indicated that RFPs had been issued to survey the market and that responses were being evaluated.

COGENERATION, NET METERING AND DISTRIBUTED GENERATION

LG&E/KU have a tariff for cogeneration customers with qualifying facilities to sell all or part of their excess power to LG&E/KU. While the net metering tariff (described below) limits customers to 30 kW, the cogeneration tariffs are available to customers with qualifying facilities greater than 30 kW. Historically, there have been no customers on these tariffs. LG&E/KU continue to investigate potential opportunities. Successful cogeneration[66] facilities are very site specific and require an industrial host operating with the appropriate economic factors to make the arrangement cost-effective.

LG&E/KU also have a net metering tariff which provides customers with the option of generating their own electricity using renewable resources. Net metering measures the difference between the energy a customer purchases from LG&E/KU and the amount of energy the customer generates using their own renewable energy source. Any excess power generated is banked as a credit to be applied against the customer's future energy purchases from LG&E/KU. The Companies have 88 net metering customers with capacities from .875KW to 29.5KW. In 2010, those customers generated 84 MWH in excess of their individual energy consumption.[67]

LG&E/KU state that a number of small technologies were considered as supply-side options and could be utilized as distributed generation.[68] The wind conversion and landfill gas options passed the screening analysis and were included in the options available for the optimal expansion plan. The Companies state that due to the relatively high cost for opportunities in Kentucky for these resources, they were not chosen as the least cost means to meet expected demand. LG&E/KU will continue to evaluate potential generation opportunities as they arise and as technologies develop further.

RENEWABLES

LG&E/KU's generation includes renewable energy generated by hydroelectric facilities at Dix Dam and Ohio Falls. The Companies indicate that rehabilitation was completed on Unit 7 in October 2006 and on Unit 6 in January 2008 at the Ohio Falls facility. Rehabilitation work on Unit 5 was scheduled to begin in 2011 and the remaining five units are to be completed by the end of 2014. Rehabilitation was restricted to the turbine/generator units. Total rehabilitation of all Ohio Falls units will result in increasing the expected summer net output of the station to 64 MW from the 48 MW capacity output prior to the rehabilitation. KU has also undertaken a project to overhaul the three Dix Dam units. This project involves rewinding the generators, refurbishing the turbine sections, and upgrading controls. The overhaul on Unit 3 was completed in 2009 with final testing completed in February 2010. Unit 2 was to be completed in 2011 and Unit

[66] Cogeneration is sometimes referred to as Combined Heat and Power or CHP.

[67] LG&E/KU IRP, Volume III, page 2.

[68] Id., PSC Recommendations, page 3.

1 was expected to be completed in 2012. The overhaul will result in a total increase in output of 6 MW. LG&E/KU state that they continue to monitor potential hydro opportunities; however, sites for additional hydro facilities on the Ohio River are limited.

OTHER NON-UTILITY SOURCES

LG&E/KU maintain firm purchase power agreements with OVEC. 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"). The DOE gave notice of reductions in its contract demand for electricity, with power and energy no longer requested after August 31, 2001. The power and energy released became available to the sponsoring companies under the Inter-Company Power Agreement. During the 2011 summer peak, LG&E/KU planned to receive 155 MW net and varying capacities during the remaining months due to unit maintenance schedules on the OVEC system.

COMPLIANCE PLANNING

LG&E/KU provided lengthy discussion of environmental issues and compliance requirements known at the time the IRP was submitted to the Commission in April 2011. Since the IRP was filed, the EPA has issued several final rules with which LG&E/KU must comply. Other rules, such as the greenhouse gas ("GHG") or CO_2 emissions rule, were not final when the IRP was submitted. This discussion focuses on those rules addressed by LG&E/KU in Case Nos. 2011-00161 and 2011-00162 in which the Companies requested certificates of public convenience and necessity and approval of their 2011 compliance plan for recovery by environmental surcharge.

On June 1, 2011 LG&E/KU filed their 2011 Environmental Compliance Plans in order to comply with the EPA's rules.[69] The EPA issued the final Cross-State Air Pollution Rule ("CSAPR") on July 6, 2011. The rule became effective on October 7, 2011, with the first phase of SO_2 and annual NO_x compliance requirements becoming effective on January 1, 2012. A second, more stringent phase of SO_2 compliance obligations will go into effect on January 1, 2014. The rule's ozone-season NO_x emission limits will become effective on May 1, 2012.[70]

The proposed National Emission Standards for Hazardous Air Pollutants ("HAPs Rule") regulates emissions of mercury, particulate matter, and hydrogen chloride ("HCl"). For coal-fired units designed to burn coal with energy content of at least 8,300 Btu/lb (which includes all of LG&E/KU's coal-fired units) the proposed HAPs Rule's

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[69] Case No. 2011-00161, Approval of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge (Ky. PSC Dec. 15, 2011), and Case No. 2011-00162, Approval of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge (Ky. PSC Dec. 15, 2011).

[70] Case No. 2011-00161, Kentucky Utilities Company (Ky. PSC Dec. 15, 2011) at 3-4.

mercury emission limit is 1.2 lbs/TBtu. The HAPs Rule's emission limit for total particulate matter from existing electric generating units is 0.030 lb/MMBtu. For HCl, the HAPs Rule's emission limit from existing electric generating units is 0.0020 lb/MMBtu. However, the HAPs Rule allows SO_2 to be measured as a surrogate for directly measuring HCl, and this is the measure that LG&E/KU will use. The SO_2 limit as a surrogate for HCl under the HAPs Rule is .2 lb/MMBtu.[71]

The EPA also proposed regulations concerning the storage of coal combustion residuals ("CCR"). In June 2010, the EPA issued a notice of proposed rulemaking to regulate CCR. CCR, often referred to as coal ash, is currently considered exempt waste under an amendment to the Resource Conservation and Recovery Act ("RCRA"). The EPA is considering two possible options for the management of coal ash disposal for public comment. Under the first proposal, EPA would list CCR as special waste when destined for disposal in landfills or surface impoundments. Under the second proposal, the EPA would regulate CCR under the section for non-hazardous wastes. Additionally, the EPA has proposed a sub-option which is also known as "D Prime." The D Prime sub-option permits existing storage facilities to operate until the end of their useful lives so that only new landfills and surface impoundments would have to comply with the new subtitle D liner, location, and operational requirements.[72]

The following projects were proposed by LG&E/KU to meet the EPA regulation and were approved Commission:

<u>KU PROJECTS</u>[73]

1. Convert the Brown Main Ash Pond to a dry-storage CCR landfill.

2. Construct Particulate Matter Control Systems to serve Brown Unit 3. Each Particulate Matter Control System comprises a pulse-jet fabric filter ("baghouse") to capture particulate matter, a Powdered Activated Carbon ("PAC") injection system to capture mercury, and a lime injection system to protect the baghouses from the corrosive effects of sulfuric acid mist ("SAM"). Also KU will install SAM mitigation equipment consisting of sorbent injection systems on Brown Units 1 and 2 that are independent of the lime injection systems associated with the baghouses.

3. Construct Particulate Matter Control Systems to serve each of the four Ghent units. Upgrade SAM mitigation equipment on Ghent Units 1, 3, and 4. Also make modifications to various systems at Ghent Units 1, 3, and 4 to expand the operating range of the units at which their existing Selective Catalytic Reduction ("SCR") equipment can function to reduce NO_x emissions.

[71] <u>Id.</u>, at 4-5.

[72] <u>Id.</u>, at 5-6.

[73] <u>Id.</u>, at 10-11.

LG&E PROJECTS[74]

1. Remove the current Flue Gas Desulfurization ("FGD") systems on Mill Creek generating Station ("Mill Creek") units 1 and 2 and construct a single new FGD to serve both units.

2. Construct one new FGD to serve Mill Creek Unit 4.

3. Remove the existing FGD at Mill Creek Unit 3 and tie Unit 3 into the current unit 4 FGD.

4. Modification to various systems at Mill Creek Units 3 and 4 to expand the operating range of the units at which their existing SCR equipment can function to reduce NOx emissions.

5. Construct Particulate Matter Control Systems to serve all generating units at Mill Creek and at Trimble County Generating Station Unit 1.

EFFICIENCY IMPROVEMENTS

GENERATION

LG&E/KU have proceeded with several activities that have maintained or improved generation efficiencies. These have included the latest controls technologies, boiler tube replacements, pulverizer rebuilds, precipitator upgrades, cooling tower rebuilds, and generator reliability improvements.[75]

Existing digital controls or distributed control systems ("DCS") have been or are scheduled to be upgraded on Brown Units 2 and 3, Green River Units 3 and 4, Mill Creek Units 2, 3, and 4, Paddy's Run Unit 13, Trimble County Unit 1 and Ohio Falls Units 5, 6, 7, and 8. LG&E/KU state that these upgrades improve reliability and performance and otherwise replace obsolete versions of these control systems. New digital controls or DCS have been or are scheduled to be installed on Ghent Unit 2, Cane Run Unit 11, and Paddy's Run Units 11 and 12. Programmable logic controllers are being implemented at the Haefling and Dix Dam Stations. These new control systems replace less efficient analog relay logic or transistor logic controls.[76]

[74] Case No. 2011-00162, Louisville Gas and Electric Company (Ky. PSC Dec. 15, 2011) at 6-10.

[75] LG&E/KU IRP, Volume III, page 8-5.

[76] Id.

A fleet-wide performance and reliability program was implemented in 2010, utilizing predictive software monitoring key equipment points and providing alerts for performance inefficiencies and equipment issues.[77]

LG&E/KU indicate that in order to improve generation availability, boiler tube studies utilizing software modeling tools and inspections have been conducted using the latest technology to identify boiler sections in need of replacement. All units across the fleet have scheduled boiler outages to replace boiler tube sections. To ensure compliance with the current particulate emission standards, partial precipitator rebuilds have taken place on E. W. Brown Units 1 and 2 and Trimble County Unit 1. Improved and modernized precipitator controls have been installed on E. W. Brown Unit 1 and Cane Run Units 4-6. These modifications have reduced incidences of output restriction necessitated by opacity emission compliance.[78]

LG&E/KU state that several efficiency improvements at various plants were implemented such as:

1. Pulverizer rebuilds on all units.

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

3. Air compressor replacement on numerous units.

4. Gas-path outlet duct and expansion joint replacement on numerous units in which sections of the boiler outlet ductwork and expansion joints are replaced, improving boiler performance issues and reducing pluggage in the unit scrubber modules.

5. The hydroelectric units at Ohio Falls and Dix Dam have benefited from significant overhaul and upgrade efforts. Ongoing overhaul work at Ohio Falls includes new water flow wicket gates, new impellers, generator rewinds, and a new unit of the Johnson valve on Dix Dam unit 2 is scheduled for 2011, which will complete the plan to mitigate the potential for complete failure of this vintage valve. Johnson valve replacements on Dix Dam units 1 and 3 occurred in 2005 and 2007. The rehabilitation project for the Ohio Falls was divided into three phases over a number of years beginning in 2001. The first two phases of the project are complete. Phase 3 entails the rehabilitation of the turbine/generator units. It will take place during the low water season in the latter six months of the year.

6. Fuel delivery and handling equipment refurbishments on numerous units.

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[77] Id., at 8-5 to 8-6.

[78] Id.

7. Air heater basket replacements on numerous units, improving air flow and boiler efficiency.

8. The condensate water treatment facility at the Mill Creek station was replaced with a higher production facility utilizing reverse osmosis technology, reducing chemical treatments, increasing efficiency, and reducing derates.

9. Heat exchangers were replaced and condensers were retubed on numerous units, improving heat transfer efficiency and improving boiler chemistry.

10. At the Cane Run station, medium voltage switchgear was upgraded, replacing equipment that experienced multiple failures that had resulted in unit outages and derates.

11. 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 was to have a "rewedge" performed in spring 2011.[79]

TRANSMISSION

The primary purpose of the LG&E/KU transmission system is to reliably transmit electrical energy from company-owned generating sources to their native load customers. The transmission system itself is designed to deliver company-owned generator output and emergency generation to meet projected customer demands and to provide contracted long-term firm transmission services. Interconnections have been established with other utilities to increase the reliability of the transmission system and to provide potential access to other economic and emergency generating sources for native load customers. The transmission system is planned to withstand simultaneous forced outages of a generator and a transmission facility during peak conditions. LG&E/KU state that they routinely identify transmission construction projects and upgrades required to maintain the adequacy of the transmission system to meet projected customer demands.[80] All transmission construction projects identified by LG&E/KU in the IRP are listed as confidential. However, the transmission construction projects identified by LG&E/KU include line reconductoring and improvement, new line construction, new transformer installation and replacement, new capacitor installation and replacement, and new breaker installation and replacement, among others.

DISTRIBUTION

Distribution planning standards and guidelines are in place for LG&E/KU. In order to meet growing customer load and improve service reliability and quality, the distribution system has been enhanced over the past three years. In an effort to achieve the enhancement of its distribution system, LG&E/KU indicate that they have

[79] Id., at 8-6 to 8-7.

[80] Id., at 8-10 to 8-11.

undertaken the construction of new substations and distribution lines along with the expansion or improvement of existing substations and distribution lines.[81] Peak substation transformer loads are monitored annually and load forecasts are developed for a 10-year planning period. LG&E/KU use the loading data and other system information to develop a joint 10-year plan for major capacity enhancements necessary to address load growth and improve system performance.

In addition to planned major enhancements, on a daily basis, LG&E/KU 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. LG&E/KU have undertaken projects each year to install, upgrade or replace distribution substation transformers to serve new customers, improve service reliability, and/or mitigate the effects on customers due to major equipment failures. LG&E/KU state that 36 distribution substations have already been targeted for review in 2011–2013 for capacity enhancements.[82] LG&E/KU have installed capacitors on the distribution system to provide more efficient use of transmission, substation and distribution facilities. LG&E/KU plan to design for near-unity power factor at the substation bus where capacitor installations on the distribution system are reasonable and feasible.

INTERVENOR COMMENTS

The Environmental Groups stated that they are gladdened that LG&E/KU call for the retirement of the aging and dirty Cane Run, Green River, and Tyrone coal-fired electric generating units and for some increase in DSM/EE efforts. The Environmental Groups state that the IRP includes a number of flaws that result in the plan failing to result in the lowest-cost approach for LG&E/KU to meet their future energy needs.[83] The list below reflects the Environmental Groups' issues relative to the supply-side resource assessment.

1. Selection of an excessive reserve margin.

2. Reliance on an unsupported assumption that there will be zero future costs related to CO_2, rather than evaluating a range of potential CO_2 costs.

3. An inadequate assessment of the full set of capital, environmental, fuel, and operating and maintenance costs facing the LG&E/KU aging coal-fired electric generating units.

4. Failure to factor in and account for uncertainty in energy planning.[84]

[81] Id., at 8-11.

[82] Id., at 8-12.

[83] Corrected Comments of the Environmental Groups, filed Dec. 1, 2011, at 1.

[84] Id.

The Environmental Groups argue that the Astrape RMS overstates the appropriate reserve margin in several ways. The RMS increases the amount of uncertainty being modeled by including both weather uncertainty and economic uncertainty. The RMS also overestimates the reserve margin required to the LOLP of 0.1.[85] They also argue that the RMS does not give any credit to demand side resources. Finally, the Environmental Groups argue that the RMS omits consideration of the Contingency Reserve Sharing Group between LG&E/KU, the Tennessee Valley Authority and East Kentucky Power Cooperative.[86]

The Environmental Groups find that LG&E/KU's failure to assume any cost related to CO_2 in the IRP is a serious shortcoming, given that the Companies generate 97 percent of their electricity from coal. The Environmental Groups believe that at some time during the planning horizon, LG&E/KU will need either to reduce CO_2 emissions or pay a fee for such emissions. The Environmental Groups cite seven companies that included CO_2 prices in recent energy planning and recommend that LG&E/KU perform some analysis similar to that included in a Synapse Energy Economics report ("Synapse Report") provided with the Environmental Groups' comments.[87]

The Environmental Groups cite the Synapse Report in claiming the IRP includes an inadequate assessment of environmental costs, increasing maintenance and other operating costs facing LG&E/KU.[88] Finally, the Environmental Groups argue that the IRP does not fully assess the uncertainties and risk associated with a resource plan.[89]

LG&E/KU RESPONSES TO INTERVENOR COMMENTS

Regarding calculation of reserve margin, LG&E/KU state the methodology used in computing the minimum reserve margin for the 2011 IRP is philosophically unchanged from the methodology employed in past IRPs. LG&E/KU indicate that several factors contribute to the higher target reserve margin in the 2011 IRP compared with the 208 IRP. First, contingency reserve obligations increased from 91 MW prior to 2007 to 212 MW in 2010, then to 240 MW in 2011 with the dissolution of the Midwest Contingency Reserve Sharing Group. Because carrying contingency reserves is a NERC requirement, LG&E/KU must plan to have adequate capacity to meet peak load and contingency reserve obligations. Second, compared with prior IRPs, LG&E/KU's future generation will be concentrated in fewer and larger units, Trimble County Unit 2, which increases the reliability impact of a forced outage event. Based on the above factors, LG&E/KU believe that an increase in reserve margin is reasonable.

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[85] A LOLP of 0.1 is the equivalent of one day of lost energy in ten years.

[86] Corrected Comments of the Environmental Groups, filed Dec. 1, 2011, at 5-6.

[87] Id., at 10-11.

[88] Id., at 11-14.

[89] Id., at 15.

The Environmental Groups comments cited several resources in support of their allegation that LG&E/KU's proposed reserve margin was unnecessarily excessive. LG&E/KU first addressed the comment that its approach inflated the reserve margin by accounting for weather and economic uncertainties in a manner that duplicated historical uncertainty. LG&E/KU responded that the reserve margin study properly considered weather and economic uncertainties as distinctly separate uncertainties in the load forecasts and that the model relied on weather-normalized loads, thereby not overstating the minimum reserve margin. LG&E/KU further explained that the economic growth uncertainty is appropriately considered through the use of a fully distributed "50/50" load forecast error that equally accounts for actual load conditions that are lower and higher than predicted.[90] Similarly, LGE/KU responded to assertions that its reserve margin study used a method to compute loss-of-load probability that was inconsistent with results from traditional computational methods by reiterating that the method employed by Astrape Consulting was based on a full-range load forecast that equally considered scenarios at the upper and lower end of the load distribution.

Next, LG&E/KU contested comparisons made to other out-of region utilities' reserve margins and argued that such comparisons did not take into account regional and local differences. According to LG&E/KU, the characteristics (size and type and reliability of generating resources, the nature of the load and the import capability for other regions) of the optimal reserve margin vary among different regions. Other factors justify an increased reserve margin from prior periods including: increased contingency reserves; fewer but larger generating units; and the historical operational challenges experienced with an actual reserve margin of 15 percent.[91] In response to comments regarding the treatment of demand-side resources as generating capacity, LG&E/KU advises that it accounted for dispatchable DSM and curtailable-service customers as generation capacity consistent with North American Electric Reliability Corporation's ("NERC's") methodology at the time of filing its 2011 IRP. Future IRPs will comply with the then-applicable NERC approach.[92]

Lastly, LG&E/KU addressed concerns that it failed to consider the Contingency Reserve Sharing Group ("CRSG") agreement maintained with the Tennessee Valley Authority and East Kentucky Power Cooperative by explaining that the arrangement is an "operational" agreement that reduces the need for contingency reserves during short-term events (less than 1-hour) required by NERC but does not reduce the reserves necessary to meet peak loads.[93]

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[90] LG&E/KU Response to Corrected Comments of Intervenors Natural Resources Defense Council and Sierra Club, received Dec. 12, 2011, at pages 7-8.

[91] Id., at pages 8-10.

[92] Id., at pages 10-11.

[93] Id., at page 11.

Regarding CO_2 costs, LG&E/KU state that CO_2 costs are unknown and the likelihood of such costs being imposed is markedly lower than they were in 2008. LG&E/KU believe it was reasonable not to include such costs in the 2011 IRP.

Finally, LG&E/KU state that they have given appropriate consideration to the cost of operating their generating units and have fully accounted for uncertainty and risk.[94]

DISCUSSION OF REASONABLENESS – RESPONSE TO 2008 RECOMMENDATIONS

In the last IRP reviewed in Case No. 2008-00408, Staff recommended that LG&E/KU discuss and provide relevant information regarding cogeneration, net metering equipment and distributed generation. Staff also recommended that LG&E/KU discuss the consideration of each in the resource plan.

LG&E/KU provided the requested information which is summarized in the COGENERATION, NET METERING and DISTRIBUTED GENERATION section of this chapter. Staff is reasonably satisfied with the information provided and the response of LG&U/KU. Specific recommendations are included below.

It was also recommended that LG&E/KU provide a specific discussion of the improvements to and more efficient utilization of transmission and distribution facilities as required by 807 KAR 5:058, Section 8 (2)(a).

The information provided by LG&E/KU is included earlier in this chapter in the Transmission and Distribution sections. Staff is satisfied with the information provided but has included specific recommendations below.

RECOMMENDATIONS

In the next IRP, LG&E/KU should continue to discuss specifically the existence of any cogeneration within their service territories and the consideration given to cogeneration in the resource plan.

LG&E/KU should continue to provide a detailed discussion of the consideration given to distributed generation in the resource plan. The Commission encourages LG&E/KU to increase their exploration of alternatives to their base load generation, and provide an update as to the availability of those alternatives within their system in the filing of the next resource plan.

LG&E/KU should continue to specifically identify and describe the net metering equipment and systems installed on each system. LG&E/KU should continue to provide a detailed discussion of the manner in which such resources were considered in the LG&E/KU resource plan should also be provided.

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[94] Id., at 18-22.

The Companies included no CO_2 costs in the supply side evaluation and did not specifically address CO_2 issues in their compliance planning. Although LG&E/KU provided what it believed was appropriate rationale for not doing so, the Staff believes that LG&E/KU should have made some attempt to evaluate the impact of potential CO_2 rules. In the 2008 IRP, in response to a Staff recommendation, LG&E/KU evaluated an "Aggressive Green Scenario" for incorporating renewable technologies into their supply portfolio, even though no legislation had been passed on a national or Kentucky level. The Environmental Groups state that the exclusion of CO_2 costs from the IRP is a shortcoming in that 97 percent of LG&E/KU's generation is from coal. Staff agrees and, therefore, recommends that LG&E/KU provide a complete discussion of compliance actions and plans relating to current and pending environmental regulations within the next resource plan. Currently, the Commission expects that environmental compliance planning be performed comprehensively, considering not only existing and pending regulations, but also those reasonably anticipated, including, but not limited to CO_2. Comprehensive planning is essential in ensuring that compliance measures proposed be implemented and to allow the Commission adequate time to perform its statutory duties in determining that new facilities and modifications are necessary in order to provide safe and adequate service, and that the rates charged are fair, just, and reasonable. LG&E/KU previously showed the capability to progressively consider issues and rules that have not been finalized by the development and consideration of an "Aggressive Green Scenario" in their 2008 IRP.

LG&E/KU should continue to study and analyze their reserve margin. The study provided by LG&E/KU supports the 16 percent reserve margin used in this IRP for planning purposes. In the next IRP, LG&E/KU should consider the comments of the Environmental Groups and explain how those comments were considered in the determination of an appropriate reserve margin for the next IRP.

As noted earlier in this report, LG&E/KU recently notified the Commission that, due to the release of the recent FERC order, they have decided not to proceed with the acquisition of the Bluegrass Generation units previously approved by the Commission. As a result, LG&E/KU should provide timely updates to the Commission related to the consideration of alternatives to the production that would have been gained by the acquisition of the Bluegrass Generation units.

SECTION 5

INTEGRATION AND PLAN OPTIMIZATION

The final step in the IRP process is to integrate supply-side and demand-side options to achieve the optimal resource plan. This section will discuss the integration process and the resulting LG&E/KU plan.

THE INTEGRATION PROCESS

LG&E/KU use the Strategist computer model in developing an optimal expansion plan, relying specifically on the model's Load Forecast Adjustment ("LFA"), Generation and Fuel ("GAF"), Proview ("PRV") and Capital Expenditure and Recovery ("CER") modules. The Strategist software program can be used to evaluate a single pre-specified plan or it can be used, as it was by LG&E/KU, to optimize a set of resource alternatives under a pre-determined set of constraints and assumptions.

The LFA module is used to develop monthly load shapes which are transferred to the GAF module for production costing purposes. The GAF module then simulates power system dispatch. All combinations of potential resource options are evaluated in the PRV optimization module to create of list of resource plans, based on pre-specified constraints, to satisfy the Companies' established reserve margin criterion. The CER module is used to calculate revenue requirements associated with forecasted capital expenditures. These revenue requirements are inputs for the PRV module based on possible in-service dates for the projected capital projects. The revenue requirement profiles for these projects are then combined with the production cost analysis from the GAF module to generate a total system revenue requirement for the planning horizon.

SENSITIVITY AND BREAK EVEN ANALYSES

Within the development of the optimal plan, sensitivity analyses were performed regarding the uncertainty in the load forecasts, retirements of coal-fired generating units and in proposed environmental regulations. Break even analyses were performed on natural gas prices and coal unit capital costs in order to determine points at which the present-value revenue requirement (PVRR) of an expansion plan in which a coal unit is installed in 2018 rather than a gas-fired combined cycle unit would be similar to the PVRR for the base case.

The load forecast sensitivity was based on 1) the expected system load growth (base case); 2) higher-than-expected system load growth (high case); and 3) lower-than-expected system load growth (low case). In each case, at least one combined cycle CT is installed in 2016. In the base case, a second combined cycle CT is installed in 2018 and a third is installed in 2025. In the high case, the second combined cycle CT is installed in the same year as the first, 2016, while the installation of the third combined cycle is moved up to 2020. In the low case, a second CT is pushed back to 2020 while the third CT is installed 2025, the same as in the base case.

The sensitivity concerning coal unit retirements and environmental regulations assumed that, due to changes or delays in some regulations, no units would be retired. In this "no unit retirements" sensitivity, the first combined cycle CT is pushed back from 2016 to 2018, the second combined cycle CT is pushed back from 2018 to 2024 and no additional capacity is added in the 15-year planning period of the IRP.

The break even analysis for natural gas prices was based on assuming that the first new generating unit added during the IRP planning period would be a combined cycle CT installed in 2016, as in the base case. Then, holding all other inputs constant, the analysis was performed to determine by how much natural gas prices would need to exceed the prices in the base case in order for a coal unit to become economical over a natural gas unit to the point that it would be the second unit added during the planning period. The analysis showed that natural gas prices would have to increase throughout the planning period by approximately 30 percent before a coal unit would replace a gas unit as the second unit installed.

The break even analysis for coal unit capital costs also assumed that the first unit added during the IRP planning period would be a combined cycle CT, installed in 2016, the same as in the base case. All other inputs were then held constant in order to determine how much those capital costs would need to decrease before a coal unit would replace the planned 2018 combined cycle CT as the second unit to be installed during the planning period. The results of the analysis indicate that coal unit capital costs would need to decrease by approximately 30 percent before being selected as the unit of choice to be installed in 2018.

OVERALL PLAN INTEGRATION

Based on their base load forecasts, LG&E/KU determined that their optimal expansion plan includes the following:

- Incremental demand reductions of roughly 60 MW annually from DSM
- Retirement of 797 MW of existing coal-fired capacity in 2016
- Addition of a 907 MW 3 X 1 combined cycle CT in 2016
- Addition of a second 907 MW 3 X 1 combined cycle CT in 2018
- Addition of a third 907 MW 3 X 1 combined cycle CT in 2025

As discussed earlier in this report, subsequent to filing their IRP, the Companies filed an application seeking authority to construct a 640 MW combined cycle gas-fired generating facility at the Cane Run Generating Station and acquire 495 MW of gas-fired peaking capacity located in Oldham County, Kentucky. While the planned acquisition of the peaking capacity was subsequently cancelled, the Companies were authorized to add the planned capacity in Case No. 2011-00375. The end result is that an additional 640 MW of combined cycle capacity is planned as part of the LG&E/KU optimal expansion plan over the 15-year planning horizon covered by their IRP.

DISCUSSION OF REASONABLENESS

As stated earlier, since filing their 2011 IRP, the Companies received approval of (1) additional and expanded DSM and EE programs in Case No. 2011-00134; and (2) new environmental compliance plans in Case Nos. 2011-00161 and 2011-00162. The implementation of these programs and plans, together with the construction of the new capacity at the Cane Run Generating Station, represents the Companies' current overall resource plan. In addition, LG&E/KU recently issued a Request for Proposals for power to make up for the cancellation of the 495 MW of peaking capacity purchase authorized in Case No. 2011-00375.

The Companies have continued to broaden and improve their integration process while addressing an increasing number of issues, especially those issues that are being driven by changing environmental compliance rules. In addressing how to comply with these rules in a reasonable, cost-effective manner, LG&E/KU have:

- analyzed and determined which generating units are to be retired
- evaluated and chosen environmental controls to be installed at other units
- selected new supply-side resources needed to meet future requirements
- expanded demand-side programs to minimize supply-side additions

The Staff is generally satisfied with how LG&E/KU have approached the changes that electric utilities nationwide are facing in the current environment. The continued enhancements in the Companies' load forecasting processes are an important aspect of improving and refining the planning, both short-term and long-term, that is necessary to meet customers' load requirements, and service expectations, in the future. The scope and depth of their reserve margin analysis, as well as the supply-side and demand-side screening analyses, are well developed and informative.

The Staff concludes that the overall integration and optimization approach used by LG&E/KU is thorough, well-documented and reasonable in all respects. It has no additional recommendations for the Companies' next IRP filing beyond those contained in Sections 2, 3 and 4 of this report.

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