Kentucky Public Service Commission

Staff Report on the

2014 Integrated Resource Plan

of Louisville Gas and Electric Company

and Kentucky Utilities Company

Case No. 2014-00131

March 2016

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 2014 Integrated Resource Plan ("IRP") to the Commission on April 21, 2014. The IRP includes the LG&E/KU plan for meeting their customers' electricity requirements for the period 2014-2028.

On May 30, 2014 an Order was issued to hold the procedural schedule in this case in abeyance after KU was notified by certain municipal wholesale customers of their intent to terminate their electric retail purchase contracts with KU. On August 12, 2014, the Companies informed the Commission they were withdrawing their application for a Certificate of Public Convenience and Necessity for a natural gas combined-cycle generating facility at the existing Green River Station ("Green River NGCC").[1] On September 15, 2014, pursuant to a Staff Notice issued on September 3, 2014, an informal conference ("IC") was held with the Companies to discuss the potential impact of the eminent departure of nine municipal wholesale customers on the joint load forecast and resource assessment plan included in the IRP. On October 1, 2014, 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. On October 17, 2014, the Companies filed, pursuant to the stipulation in the September 15, 2014 IC, a resource assessment addendum to the 2014 IRP ("Addendum") which updated the load forecast to reflect the impacts of the loss of the municipal customers and an updated resource assessment reflecting the withdrawal of the application for the Green River NGCC, including a solution to address the interim reserve margin issue discussed at the IC.

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[1] *See* Case No. 2014-00002, *Joint Application of Louisville Gas & Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station* (Ky. PSC Dec. 19, 2014).

In response to a Staff's Request for Information regarding the Companies planned closure of the Green River Units 3 and 4 in April of 2015, on November 21, 2014, the Companies stated that "since the filing of the IRP, recent events on LG&E and KU's transmission network and the interconnected utilities have raised concerns over reliability impacts created by the planned retirement of these units and triggered the need for additional study."[2] As a result, the Companies have requested and received approval from the Kentucky Division of Air Quality to operate Green River Units 3 and 4 through April 2016, at which time the units will be retired.

On January 29, 2015, an amended procedural schedule Order was issued after the Commission found that there were unresolved issues related to the January 8, 2015 announcement that the Companies had decided not to retire two coal-fired generation units at the E. W. Brown station.[3] The schedule provided for an additional round of data requests to LG&E/KU and revised the dates for the written comments of 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, Inc. ("KIUC"), and Wallace McMullen 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, changed its name 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 397,000 customers in Jefferson County and 16 surrounding counties with a total service area covering approximately 1,300 square miles. It supplies natural gas to over 321,000 customers.[4]

KU supplies retail electricity in 77 Kentucky counties to approximately 543,000 customers in a service area covering approximately 4,800 non-contiguous square miles, in five Virginia counties, under the corporate name of Old Dominion Power ("ODP") and

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[2] LG&E/KU's Response to Staff's First Request for Information ("Staff's First Request"), Item 1.

[3] *See Platts Megawatt Daily*, January 8, 2015, at 1.

[4] IRP, Volume I at 5-1 and 5-2.

to five customers in Tennessee.[5] It currently sells wholesale electricity to 12 municipal electric systems in Kentucky.[6]

The Companies' net summer generation capacity in 2014 was 7,906 Megawatts ("MW").[7] This consisted of 5,742 MW of coal-fired capacity, 2,086 MW of gas-fired capacity and 78 MW of hydroelectric ("hydro") power.[8] 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.[9] 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.[10] KU experienced its highest summer peak demand of 4,354 MW on that same day.[11] The Companies' highest combined system winter peak demand of 7,114 MW occurred on January 6, 2014, ending at 9:00 p.m. Eastern Standard Time.[12] KU experienced its all-time system peak demand of 5,068 MW during this hour.[13]

The purpose of this report is to review and evaluate the Companies' Joint IRP in accordance with 807 KAR 5:058, Section 11(3), which requires 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 its next IRP filing. 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

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[5] *Id.* at 5-1.

[6] *Id.*

[7] *Id.* at 5-4.

[8] *Id.* at 5-3.

[9] *Id.* at 5-2.

[10] *Id.* at 5-4.

[11] Case No. 2011-00140, *The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company* ("2011 IRP") (Ky. PSC May 13, 2013), Staff Report at 3.

[12] IRP, Volume I at 5-4.

[13] *Id.*

- The report also includes an incremental component noting any significant changes from the Companies' most recent IRP, filed in 2011.

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 examined 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 6,434 MW, their weather-normalized 2013 peak, to 7,766 MW in 2028, reflecting a growth rate of .8 percent per year.[14] Their winter peak load is expected to increase from 5,907 MW to 6,595 MW over the same period, reflecting a growth rate of .7 percent.[15] Energy requirements are projected to increase from 34,874,000 MWh in 2013 to 39,279,000 MWh in 2028, which reflects an annual growth rate of .7 percent.[16]

The LG&E/KU IRP was developed based on a minimum reserve margin criterion of 16 percent.[17] Based on Demand-Side Management ("DSM") programs in place at the

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14 *Id.* at 5-22.

15 *Id.*

16 *Id.* at 5-20.

17 IRP, Volume III at 25.

time the IRP was filed, along with new programs proposed in Case No. 2014-00003,[18] the Companies expect to have a 500-MW reduction in summer peak demand by the end of 2018 and realize a total energy savings of 200 gigawatt hours ("GWh").[19] LG&E/KU's base case resource plan, in the Mid Carbon, Mid gas price scenarios, includes the retirement of 438 MW of coal-fired capacity at the E.W. Brown and Green River generating stations, and the addition of 1,474 MW of combined-cycle gas-fired capacity.[20]

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.

The report contains a number of recommendations for the Companies' next IRP. The majority of the Staff's recommendations are contained in Sections 2, 3, and 4.

It must be noted that departures from the filing schedule in 807 KAR 5:058 have caused overlaps of IRP filings. To help minimize future overlaps, in conjunction with changes in other utilities' IRP filing schedules, Staff recommends to the Commission a filing date for LG&E/KU's next IRP of November 1, 2018.

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[18] *See* Case No. 2014-00003, *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. 14, 2014).

[19] IRP, Volume I at 5-39 and 8-30.

[20] Addendum at 7.

SECTION 2

LOAD FORECASTING

BACKGROUND

This section reviews LG&E's and KU's projected load growth and forecasting methodology. The Companies' forecasting approach is based on econometric modeling of energy sales by customer, but it also incorporates specific information on the prospective energy requirements of their largest customers. Data inputs to the forecasting process come from several sources. Macroeconomic and demographic forecast data are provided by IHS Global Insight ("Global Insight"). Information from both Global Insight's 2013 Long-Term Macro Forecast and its Population and Household Forecast is used in the Companies' forecasts.[21] Weather data is provided by the National Climatic Data Center, a branch of the National Oceanic and Atmospheric Administration ("NOAA") of the U.S. Department of Commerce. Modeling of appliance saturations and energy-efficiency ("EE") trends uses regional databases developed by the U.S. Energy Information Administration ("EIA") which are provided to the Companies by Itron.

Growth in annual real U.S. gross domestic production ("GDP") is forecasted to average 2.5 percent over the forecast period ending in 2042, 0.2 percent below the most recent 30-year historical average. This lower growth is attributed to slower growth in the labor force due to the retirements of those considered to be "Baby Boomers." Real personal disposable income is forecasted to increase 2.4 percent annually over the next 30 years, or 0.3 percent below the 30-year historical average.[22] Based on data from the Census Bureau, the population growth rate is expected to slow.

Kentucky's real gross state production ("RGSP") is forecasted to increase 2.0 percent annually over the next 30 years, which is 0.2 percent less than the average for the period 1990-2007.[23] Kentucky's real personal disposable income is forecasted to rise 2.2 percent annually over the next 30 years compared to the 30-year historical average of 2.4 percent.[24] LG&E/ KU developed their long-term Base Case forecast using "the best information available"[25] at the time the IRP was being prepared.

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[21] IRP, Volume I, Section 5.(2) at 5-12.

[22] *Id.*

[23] RGSP for Kentucky is only available beginning in 1990. The historical period ends in 2007 to reflect results not impacted by the 2008 recession.

[24] IRP, Volume I, Section 5.(2) at 5-13.

[25] *Id.* at 5-17.

Given the uncertainty inherent in long-term forecasts, the Companies developed High Case and Low Case forecasts to reflect the statistical uncertainty about the Base Case forecast. In the High Case forecast, energy requirements and peak demand are approximately 6 percent higher in 2018 than in the Base Case. Energy requirements and peak demand are approximately 6 percent lower in 2018 in the Low Case forecast compared to the Base Case.[26]

Compared to forecasts in the 2011 IRP, the Companies' 2014 forecasts reflect sizeable reductions in both energy requirements and demand. These reductions are driven by the slow return of jobs and economic growth after the end of the 2008–2009 recession. LG&E and KU are forecasting a downward trend in sales in the near-term years of their forecasts and a continuing lower-than-historical rate of growth in the later years of the forecast period ending in 2028. The forecasted annual growth rate in sales during the forecast period is 0.7 percent, compared to 1.2 percent in the 2011 IRP. With an annual growth rate roughly one-half the prior growth rate, the sales level forecasted in the 2011 IRP to be reached in 2018 is now forecasted to be reached in 2027.

LOAD FORECAST METHODOLOGY

LG&E's and KU's 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. 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, as mentioned earlier, are obtained from customers' historical use and specific information provided by individual customers.

The weather data obtained from NOAA covered the most recent 20-year period available at the time the Companies were preparing the IRP. The data, from Lexington, Louisville, and Bristol, Tennessee, include heating and cooling degree days for the 20-year period ending in 2012.[27] Degree days used in the models are all on a 65-degree Fahrenheit base.

Changes in Methodology Since the 2011 IRP

The Companies have implemented the following changes since the 2011 IRP:

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[26] *Id.*, Section 7.(7)(e) at 7-29.

[27] Bristol, Tennessee, weather data is used in the forecast for the five Virginia counties served by ODP.

- In the 2011 IRP, class-specific load profiles were used to develop hourly demand forecasts in order to better reflect demand-side management programs that impact the load profile of specific classes. In the 2014 IRP, this process was enhanced by using historical hourly shapes, by company, month, and day of the week with different weather ranges to better reflect load shapes for different temperature ranges.
- In the 2011 IRP, the responses provided in home appliance saturation surveys of both LG&E and KU customers were used to develop assumptions for the residential forecasting models. For the 2014 IRP, commercial end-use surveys were conducted in addition to residential surveys, and the responses were used to develop assumptions for commercial forecasting models.[28]
- RGSP was used as the main economic driver of the forecasts of small commercial sales in the 2011 IRP. In the 2014 IRP, the Companies also used Kentucky retail employment as a key driver in the small commercial forecast.[29]

After the Companies' energy forecasts are complete, they are converted from a billed basis to a calendar basis and are then used to create hourly sales forecasts. The hourly sales forecasts are then adjusted to reflect company uses and system losses to produce a forecast of hourly energy requirements.

LG&E SALES FORECAST

Generally, the same forecast methodology is used by LG&E and KU. LG&E's sales forecast is made up of 13 models, each of which forecasts the number of customers, use-per-customer, or total sales on a monthly basis, and is associated with one or more homogenous rate classes. LG&E's energy sales are forecasted to grow from 11,908 GWh in 2014 to 13,201 GWh in 2028, which represents a 0.7 percent average annual growth rate.[30] This compares to a 1.4 percent average annual growth rate in the Companies' 2011 IRP.[31] LG&E forecasts for a single jurisdiction — the Kentucky retail jurisdiction.

LG&E RESIDENTIAL FORECAST

LG&E's residential forecast includes customers on the Residential Service ("RS") and Volunteer Fire Department rate schedules. It is the product of the forecasted number of customers and average use per customer which is forecasted using a SAE model. The residential forecast is a function of weather, economic conditions, equipment saturation, household demographics, and usage levels. Residential energy sales are forecasted to increase from 4,234 GWh in 2014 to 5,092 GWh in 2028,

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[28] IRP, Volume I, Section 7.(7)(f) at 7-32.

[29] *Id.* at 7-33.

[30] *Id.*, Section 6, Table 6.(1)-11 at 6-19.

[31] *Id.*

representing a 1.3 percent average annual growth rate,[32] which compares to 1.5 percent in the 2011 IRP.

LG&E COMMERCIAL FORECAST

LG&E's commercial forecast group consists of two commercial models: LG&E small commercial and LG&E large commercial. The small commercial customers include those who receive service under the General Service tariff. The large commercial customers include those who receive service under the Commercial Power Service and Commercial Time-of-Day tariffs. The commercial forecast is the product of average use-per-customer (obtained using a SAE model) and a customer forecast. Commercial energy sales are forecasted to increase from 3,695 GWh in 2014 to 3,763 GWh in 2028, which represents a 0.1 percent average annual growth rate,[33] compared to the 1.8 percent average annual growth rate in the 2011 IRP.

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

Industrial energy sales have rebounded more strongly since the end of the 2008–2009 recession than have sales to other customer classes. Industrial energy sales are forecasted to increase from 2,823 GWh in 2014 to 3,197 GWh in 2028, representing a 0.9 percent average annual growth rate.[34] This reflects an increase from the 0.5 percent growth rate reflected in the 2011 IRP forecast.

LG&E PUBLIC AUTHORITY FORECAST

LG&E's public authority (largely governmental entities) sales are forecasted to be is essentially flat from 2014 to 2028 due to a major customer's change in operation. Public authority energy sales are forecasted to decrease slightly from 1,155 GWh in 2014 to 1,148 GWh in 2028.[35]

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[32] *Id.*, Section 6, Table 6.(1)-12 at 6-21.

[33] *Id.*, Table 6.(1)-14, at 6-23.

[34] *Id.*, Table 6.(1)-15, at 6-24.

[35] *Id.*, Table 6.(1)-16, at 6-25.

LG&E PEAK DEMAND FORECAST

LG&E forecasts its peak demand to increase from 2,655 MW in 2014 to 2,982 MW in 2028, which represents an average annual growth rate of 0.8 percent.[36] This compares to a 1.4 percent growth rate in the Companies' 2011 IRP and reflects a 419 MW reduction in forecasted peak demand in 2028 compared to the 2011 IRP.

KU SALES FORECASTS[37]

KU's sales forecast comprises 28 models, each of which forecasts the number of customers, use-per-customer, or total sales on a monthly basis and is associated with one or more homogenous rate classes. KU sells to three jurisdictional groups: Kentucky retail, Kentucky wholesale,[38] and Virginia retail.[39] KU's energy sales are forecasted to grow from 21,774 GWh in 2014 to 23,837 GWh in 2028[40] for a 0.6 percent average annual growth rate compared to a 1.5 percent average growth rate in the 2011 IRP.[41]

KU RESIDENTIAL FORECAST

As previously discussed, the residential forecast is a function of weather, economic conditions, household demographics, and equipment saturation and usage levels. Residential energy sales are forecast to increase from 6,727 GWh in 2014 to 7,611 GWh in 2028, which represents an average annual growth rate of 0.9 percent.[42] This compares to a 1.6 percent annual growth rate in the 2011 IRP.

KU COMMERCIAL FORECAST

KU's commercial customers consist of those who receive service under the General Service, TOD-Secondary and All-Electric Schools tariffs. KU's commercial sales were slow to recover after the 2008–2009 recession, as some large commercial customers closed their businesses. In addition, by late 2011, 137 customers changed

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[36] *Id.*, Table 6.(1)-17 at 6-26.

[37] In addition to the customer class forecasts discussed in this section, KU also forecasts its lighting sales. These sales, which account for less than two-tenths of one percent of KU's energy sales, are forecasted to remain flat at 39–40 GWh over the forecast period.

[38] The wholesale group consists of 12 municipal utilities.

[39] IRP, Volume I, Section 5.(1) at 5-1.

[40] *Id.*, Section 6(1), Table 6.(1)-3 at 6-8.

[41] *Id.* Energy sales include KU's Kentucky and Virginia retail sales and its wholesale sales.

[42] *Id.*, Section 6.(1), Table 6.(1)-4 at 6-10.

from a Commercial to an Industrial classification, further lowering the base line for the 2014 forecast.[43] The forecasted annual growth rate for the period 2014-2028 is 0.6 percent, with sales increasing from 4,257 GWh in 2014 to 4,650 GWh in 2028. This compares to an average annual growth rate of 1.6 percent in the 2011 IRP.[44]

KU INDUSTRIAL FORECAST

The industrial forecast involves multiple models. A separate industrial production index related to mining was included for Mine Power customers. North American Stainless ("NAS"), with its arc furnace, is the only customer on the Industrial Service rate. The forecast for NAS is based on historical usage and direct discussions with the customer. Taken together, industrial energy sales are forecasted to grow from 7,188 GWh in 2014 to 7,621 GWh in 2028, reflecting a 0.4 percent average annual growth rate, which compares to a 1.6 percent average annual growth rate in the 2011 IRP.[45]

KU PUBLIC AUTHORITY FORECAST

KU's public authority sales (largely government entities) are forecasted to increase from 1,632 GWh in 2014 to 1,703 GWh in 2028. This reflects an average annual growth rate of 0.3 percent compared to an average annual growth rate of 1.3 percent in the Companies' 2011 IRP.[46]

KU MUNICIPAL FORECAST

The municipal group forecast is a function of weather and number of households in the counties encompassing the various municipalities. There are three categories of municipal customers: Transmission Municipals; Primary Municipals; and the city of Paris. The city of Paris is forecasted separately because it generates a portion of its own power. Energy sales to this class are forecasted in the IRP to grow from 1,969 GWh in 2014 to 2,252 GWh in 2028, which reflects a 1.0 percent average annual growth rate.[47] In April 2014, nine of these customers provided notices of termination of their wholesale power agreements. Due to these terminations, KU's forecasted summer peak demand will be reduced from what was included in its IRP by approximately 325 MW after April 30, 2019, while annual energy sales are expected to be 1,127 GWh lower in 2019.[48]

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[43] *Id.* at 6-11.

[44] *Id.*, Table 6.(1)-6, at 6-12.

[45] *Id.*, Table 6.(1)-7, at 6-13.

[46] *Id.*, Table 6.(1)-8, at 6-14.

[47] *Id.*, Table 6.(1)-9, at 6-15.

[48] Addendum, Appendix A.

KU PEAK DEMAND FORECAST

KU forecasts its peak demand to increase from 4,334 MW in 2014 to 4,784 MW in 2028, which represents an average annual growth rate of 0.7 percent.[49] This compares to a 1.4 percent growth rate in the 2011 IRP and reflects a 430-MW reduction in forecasted peak demand in 2028 compared to the 2011 IRP.[50] This is reduced further due to the contract terminations of the municipal customers discussed earlier.

OLD DOMINION POWER

ODP operates in five counties in southwestern Virginia. Forecasts for ODP customer classes are obtained separately and are modeled in a fashion similarly to that of KU's customer classes. Energy sales to ODP are forecasted to increase from 909 GWh in 2014 to 960 GWh in 2028, representing an average annual growth rate of 0.3 percent.[51]

DEMAND-SIDE MANAGEMENT

LG&E and KU prepare forecasts annually. Their forecasts capture changes in saturation levels of appliances and equipment in the market, and also help capture new emerging EE technologies entering the market and DSM programs approved as of 2014. The cumulative impacts of all new and existing DSM programs for the Companies are expected to grow from 832.7 GWh in 2014 to 1,169.3 GWh in 2018.[52] Summer peak reductions from DSM programs are forecasted to range from 339.9 MW in 2014 to 500.2 MW in 2018.[53] The forecasts reflected no changes in EE/DSM impacts in the years after 2018.

The Companies state that their DSM and EE programs do not further reduce demand and energy beyond 2018, based on the results of an Energy Efficiency Potential Study performed for them by The Cadmus Group.[54] The study involved assessments of EE potential in the residential and commercial sectors and considered a wide range of EE technologies.[55] According to the study, the Companies are on track to

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[49] IRP, Volume I, Table 6.(1)-10, at 6-16.

[50] *Id.*

[51] *Id.*, Table 7.(7)(b), at 7-18.

[52] *Id.*, Section 8.(3)(e)(3), Table 8.(3)(e)(3)-2 at 8-33.

[53] *Id.* at 8-34.

[54] *Id.* at 8-29.

[55] The Companies' existing DSM programs are approved through the end of 2018.

exhaust their achievable EE potential from currently approved programs by 2018.[56] The Companies do continue to study DSM opportunities and anticipate adding cost-effective new or expanded DSM programs and measures for future implementation.[57]

SENSITIVITY ANALYSIS

To address uncertainty, LG&E and KU developed scenarios to support sensitivity analyses of their resource plans. As in prior IRPs, these scenarios were based on probabilistic simulation of the historical volatility exhibited by each company's weather-normalized year-over-year sales trend.[58] While there are a number of uncertainties that could impact the Companies' resource decisions, they identified uncertainties in native load, natural gas prices, and greenhouse gas ("GHG") regulation as the most important in evaluating their resource decisions.

The Companies acquire new supply-side or demand-side resources to meet native load customers' future energy needs. Hence, the forecast of those needs has a significant impact on their optimal expansion plan. Future native load is driven by future economic activity, the adoption rate of DSM programs, and the development of new electric end uses. With experience of how the effects of the recession of 2008–2009 affected, and continue to affect, both demand and energy consumption, the need for sensitivity analyses should not be understated.

Natural gas has become the fuel of choice for fossil generation as a result of the New Source Performance Standards proposed by the U.S. Environmental Protection Agency ("EPA"). The Companies state that the abundance of natural gas supply resulting from advanced drilling technologies has put downward pressure on natural gas prices and greatly enhanced the economics of Natural Gas Combined Cycle ("NGCC") generation. Conversely, the Companies state that the impending nationwide retirement of coal-fired generating units and related shift to NGCC will increase the demand for natural gas and put upward pressure on prices. To address long-term natural gas price uncertainty, the Companies developed "Low," "Mid," and "High" natural gas price scenarios.[59]

To evaluate GHG regulation, the Companies developed two approaches: the first approach puts a price on each ton of carbon dioxide ("CO_2"), while the second approach puts a cap on CO_2 mass emissions. Under the first approach, "Mid" and "Zero" CO_2 price scenarios were considered. In the "Mid" CO_2 price scenario, CO_2 prices begin to

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[56] IRP, Volume I at 8-29.

[57] Joint Response of LG&E/KU to the Environmental Intervenors Comments ("Companies' Joint Reply") at 11.

[58] *Id.*, Volume I, Section 5.(6) at 5-44.

[59] *Id.*, Section 5.(2) at 5-17.

appear in 2020, as listed in Table 2.1 below. The "Zero" CO_2 price scenario was considered because of uncertainty regarding future GHG regulation of existing generating units.[60]

TABLE 2.1

Year	Mid CO2 Price ($/short ton)
2020	17
2021	20
2022	23
2023	26
2024	30
2025	33
2026	37
2027	40
2028	44
2029	48

The second approach is based on the Obama administration's Climate Action Plan released in June 2013, which calls for a 17 percent reduction in CO_2 emissions from 2005 levels.[61] Under this "CO_2 mass emissions cap" scenario, the Companies are limited to 29.4 million tons of CO_2 annually beginning in 2020.[62]

For LG&E, the 2018 base case energy sales forecast is 12,961 GWh while the high and low energy sales forecasts are 13,386 GWh and 12,536 GWh, respectively. Similarly, the 2018 peak demand forecast is 2,737 MW, with corresponding high and low forecasts of 2,827 MW and 2,647 MW, respectively. By 2028, the base case energy sales and peak demand are 13,967 GWh and 2,982 MW, respectively. Corresponding high and low bands range from 14,786 GWh to 13,147 GWh and 3,157 MW to 2,807 MW.[63]

For KU, the 2018 base case energy sales forecast is 23,723 GWh, and the high and low energy sales forecasts are 25,217 GWh and 22,230 GWh, respectively. Similarly, the 2018 peak demand forecast is 4,462 MW, with corresponding high and low forecasts of 4,743 MW and 4,181 MW, respectively. By 2028, the base case energy sales and peak demand are 25,312 GWh and 4,784 MW, respectively.

60 *Id.* at 5-18.

61 The final version of the Clean Power Plan requires an overall reduction in carbon emissions of 32 percent over 2005 levels by 2030

62 IRP, Volume I at 5-18.

63 *Id.*, Section 7.(7)(e), LG&E Tables 7.(7)(e)-1 and 7.(7)(e)-2 at 7-51.

Corresponding high and low bands range from 27,486 GWh to 23,138 GWh, and 5,195 MW to 4,373 MW.[64]

INTERVENOR COMMENTS

The Sierra Club, the only intervenor who filed comments, contends that the Companies' load growth projections are flawed because they reflect no change in EE impacts beyond 2018. It states that instead of assuming "that energy efficiency gains grind to a halt in 2018, the Companies should be considering a range of levels of DSM programs in the years after 2018."[65] The Sierra Club further states that the Companies should consider alternative amounts of DSM, as either a supply-side resource or a load modifier, for the years in the planning period not covered by an approved DSM plan.[66]

The Sierra Club claims that LG&E's and KU's natural gas price analysis, in which the "Low," "Mid," and "High" price scenarios were weighted equally, is also flawed, asserting that the "Mid" price forecast should have been treated as the scenario most likely to occur.[67] According to the Sierra Club, although EIA assigned no probability to its "Mid" price forecast in its reference case, forecasting agencies as well as utilities often treat a "Mid" price forecast as the forecast most likely to occur, and consider the sensitivities that bound the "Mid" price as less likely to occur.[68] The Sierra Club states that if the mid gas price is weighted more heavily and the sensitivities weighted less, average capacity factors of the existing coal-fired generating units change from those based on equal weighting of the natural gas price forecasts. Depending on the weighting, the Sierra Club claims that the retirement of KU's E.W. Brown Unit 1 could be triggered as early as 2020.[69]

The Sierra Club, noting that the Companies' actual energy sales have been less than their forecasted sales in eight of the last ten years, contends that some adjustment should be made to the Companies' load forecasts.[70] The Sierra Club suggests that the Companies have several options for addressing this issue, from altering the forecasting methodology to applying a correction factor at the end of the forecasting process. It concludes by stating that however the Companies address this matter, they need to

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[64] *Id.*, KU Tables 7.7e-1 at 7-30 and 7.(7)(e)-2 at 7-31.

[65] Comments of the Environmental Intervenors at 3.

[66] *Id.* at 32.

[67] *Id.* at 19.

[68] *Id.*

[69] *Id.* at 20.

[70] *Id.* at 30–32.

account for their tendency in the past ten years to forecast energy sales levels that are greater than their actual energy sales levels.[71]

LG&E/KU REPLY COMMENTS

In response to the Sierra Club's claim that their load growth projections are flawed because they reflect no change in EE impacts beyond 2018, the Companies state that their IRP used the best DSM/EE data available at the time of filing: the Cadmus Energy-Efficiency Potential Study filed in Case No. 2014-00003, their most recent DSM case.[72] The Companies stated that the Cadmus study had noted that LG&E and KU were "rapidly depleting the achievable energy potential in their service territories, and were on track to exhaust their achievable energy efficiency potential by 2018."[73] The Companies stated that showing no additional EE impacts beyond 2018 does not mean that they will end their DSM-EE programs in 2018, or that they will not introduce new programs. It merely means that the currently approved DSM-EE programs are on track to exhaust their achievable EE potential by 2018.[74]

Concerning the Sierra Club's contention that their analysis was flawed because they did not assign probabilities to the natural gas price scenarios modeled in their IRP, the Companies explain that they used three gas price forecasts from EIA and that EIA did not assign probabilities to those forecasts. The Companies state that they followed an approach similar to EIA's: they did not assign probabilities to the different gas price forecasts while they modeled a number of scenarios using different assumptions to determine the most robust generating technologies across a range of assumptions.[75]

Regarding the Sierra Club's criticism that their forecasted energy sales over the last ten years have typically exceeded their actual energy sales, the Companies note that the average annual difference is less than 1.5 percent. They state that, given the number of factors beyond their control that influence energy consumption, such a low average is "actually remarkably good."[76]

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[71] *Id.*

[72] Companies' Joint Reply at 8–9.

[73] *Id.* at 9.

[74] *Id.*

[75] *Id.* at 8.

[76] *Id.* at 16.

RESPONSE TO 2011 RECOMMENDATIONS / DISCUSSION OF REASONABLENESS

Response to 2011 Recommendations

In its report on LG&E/KU's 2011 IRP, Staff made three recommendations relative to forecasting. The recommendations and the Companies' responses follow:

- Continue to review the potential impact of new and pending environmental requirements and report on how these requirements are incorporated into their load forecasts and related risk analysis in the next IRP.

The Companies stated that their load forecasts do not explicitly incorporate new and pending environmental requirements. However, the forecast models incorporate price and economic series to take into account the changes in economic conditions resulting from such environmental requirements.[77]

- Continue the Companies' efforts to further refine and integrate their load forecasting process where appropriate and report on these efforts in their next IRP.

Concerning their load forecasting process, the Companies point to the changes discussed earlier under the heading Changes in Methodology Since the 2011 IRP.[78]

- 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.

The Companies stated that the price elasticity of demand used in the 2014 IRP forecast for residential customers was -0.1, while the price elasticity of demand for commercial customers was -0.05. These values are specific to the SAE model used for residential and commercial forecasting, which capture additional price responsiveness by accounting for changes in appliance efficiency. According to the Companies, when using -0.1 and -0.05 for residential and commercial elasticity of demand as an input, the SAE model provided results that were consistent with historical energy consumption and provided a reasonable forecast.[79]

Discussion of Reasonableness

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

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[77] IRP, Volume III at 1.

[78] *Id.*

[79] *Id.*

commends the Companies for enhancements to the development of hourly demand forecasts that better reflect load shapes for different temperature ranges.

Staff believes that the Companies should reflect changes in EE impacts in their forecasts for the entire 15-year planning period irrespective of the status of their DSM/EE programs.

RECOMMENDATIONS

Staff makes the recommendations below concerning the Companies' energy and demand forecasts for their next IRP.

The potential impact of existing and future environmental regulations on the price of electricity and other economic variables that affect the price of electricity remains a topic of significant interest within the electric utility industry and the utility regulatory community. Therefore, the effects of such regulations should continue to be examined by LG&E and KU as a part of their load forecasts and sensitivity analyses.

The potential continues to exist for future increases in electricity prices due to stricter environmental requirements that are large enough to affect consumer behavior and energy consumption. An updated analysis and discussion of how such price increases may impact the elasticity of customer demand should be included in the Companies' next IRP.

As required by the IRP regulation (807 KAR 5:058), LG&E and KU should reflect anticipated changes in EE impacts in their forecasts for the full planning period included in the IRP.

SECTION 3

DEMAND-SIDE MANAGEMENT/ENERGY EFFICIENCY

This section discusses the DSM/EE aspects of the LG&E/KU IRP. At the time of the IRP filing, the Companies had filed a DSM application in Case No. 2014-00003[80] proposing continuation and some modification of existing programs and the addition of a new program, and deleting four programs. The Commission has since approved LG&E/KU's application.

DSM/EE PROGRAMS THAT EXPIRED AT THE END OF 2014

The following programs, which were approved in Case No. 2007-00319[81] through 2014, expired at the end of 2014 because they will reach the end of their approval cycle and useful life.

1. Residential High Efficiency Lighting – This program promotes an increased use of Energy Star-rated compact fluorescent light ("CFL") bulbs within the residential customer sector. The Companies use this program to increase customer awareness of the environmental and financial benefits of CFLs. The program distributes the CFLs through direct mail.

2. Residential New Construction – This program is designed to reduce residential energy usage and facilitate market transformation by creating a shift in builders' new home construction to include energy-efficient construction practices. Builders who are part of the program can take advantage of technical training classes, gain additional exposure to potential customers, and receive incentives to help offset costs when including more energy-efficient features during home construction. The Companies reimburse the cost of plan reviews and inspection costs related to an Energy Star or Home Energy Rating System ("HERS") home certification.

3. Residential and Commercial HVAC Diagnostic and Tune-up Program – The objective of this program is to reduce peak demand and energy use by conducting a diagnostic performance check on residential and small commercial unitary air conditioning and heat pump units, air-restricted indoor and outdoor coils, and over- and under-refrigerant charge. The program targets customers that likely have heating, ventilation, and air conditioning ("HVAC") system performance issues. There are no incentives paid directly to customers. Customers are charged a discounted fixed fee for

[80] Case No. 2014-00003, *Louisville Gas and Electric Company and Kentucky Utilities* (Ky. PSC Jan. 17, 2014).

[81] *See* Case No. 2007-00319, *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 Mar. 31, 2008).

the diagnosis and, if needed, a similar fee for implementation of corrective actions. The program pays the portion of diagnostic and tune-up cost in excess of the fixed charge.

4. Dealer Referral Network – This program provides a web-based Dealer Referral Network designed to deliver the following services to program constituents:

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

DSM/EE PROGRAMS THAT REMAIN UNCHANGED

The following programs remain unchanged and continue at their currently approved funding levels and duration (through 2018). Through ongoing and comprehensive analysis, LG&E/KU will determine whether to pursue these programs further in a later DSM expansion filing or discontinue the programs in 2018. The program performance of each of these programs indicates no program change was necessary at this time.

1. Smart Energy Profile Program – This program provides a portion of the highest-consuming residential customers with a customized report containing tips, tools and EE programming recommendations based on individual household energy consumption. These reports are benchmarked against similar properties in the same locality. The report includes a comparison of the customer's energy usage to that of similar houses (collectively) and a comparison to the customer's own energy usage in the prior year. The report is designed to help customers understand and make better-informed choices relating to energy usage and associated costs.

2. Residential Load Management/Demand Conservation Program – This program employs switches in homes to help reduce the demand for electricity during peak times. The program is designed so the Companies can communicate with the switches to cycle central air conditioning units, heat pumps, electric water heaters, and pool pumps off and on through a predetermined sequence.

3. Residential Refrigerator Removal Program – This program provides removal and recycling of working, inefficient secondary refrigerators and freezers from customer households. Customers participating in this program are provided a one-time incentive.

4. Residential Low Income Weatherization Program ("WeCare") – The WeCare program is an education and weatherization program designed to reduce energy consumption of low-income customers. The program provides energy audits, energy education, blower door tests, and installation of weatherization and energy conservation measures. Qualified customers receive energy conservation measures

ranging from \$0 to \$2,100, based upon the customer's most recent 12-month energy usage and the results of an energy audit.

5. Program Development and Administration – This program was established to capture costs incurred in the development and administration of EE programs in which it is difficult to assign costs specifically to an individual program. The function of the program includes, but is not limited to, new program concept and initial design; market research related to new programming; research and technical evaluation of new technologies and programs; overall program tracking and management; development of key personnel; and membership in associated trade organizations.

ENHANCED DSM/EE PROGRAMS

The following programs were enhanced and continued through 2018, some include additional funding.

1. Commercial Load Management/Demand Conservation Program – This program employs switches or interfaces to customer equipment in small and large commercial businesses to help reduce the demand for electricity during peak times. The program communicates with the switches or interfaces to cycle equipment.

This program enhancement is placing more focus on the large commercial aspect of the program. The small commercial program has been available since 2001 and has produced approximately 4 MW of demand reduction. The large commercial program has provided 10 MW of demand reduction in two years of operation. Due to its success, more focus will be placed on the large commercial program, with an additional \$5.7 million[82] in capital, operation and maintenance funding for 2015-2018. The small commercial program is proposed to remain unchanged, with currently enrolled customers still eligible for incentives and eligible customers still able to enroll.

2. Residential Incentives Program – The Residential Incentives Program encourages customers to purchase and install various Energy Star appliances, HVAC equipment, or window films that meet certain requirements, qualifying customers for an incentive.

The program has experienced success since its inception due to its simple design and variety of appliances rebated. As of November 2013, the Companies surpassed the anticipated rebated appliances by 125 percent and their forecasted financial spend by 107 percent. To address the exceedingly high customer participation and prevent early program termination, the Companies sought approval for increased incentive dollars to fund the program through 2018 consistent with the original filing for

[82] Case No. 2014-00003, *Louisville Gas and Electric Company and Kentucky Utilities Company* (Ky. PSC Nov. 14, 2014), Direct Testimony of Michael E. Hornung, Application, Exhibit MEH-1 at 23.

this program. As requested, the Commission granted an additional $5.7 million[83] in funding.

3. Customer Education and Public Information Program – This program is designed to help customers make sound energy-use decisions, increase control over energy bills, and empower them to actively manage their energy usage. The Customer Education and Public Information program is implemented through a mass media campaign and an elementary and middle school program. The mass media campaign includes public service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to teach concepts such as basic energy and EE concepts.

4. Commercial Conservation/Commercial Incentives Program – This program is designed to increase the implementation of EE measures by providing financial incentives to assist with the replacement of aging and less efficient equipment and for new construction built beyond code requirements. The Program also offers an online tool providing recommendations for EE improvements. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements. A prescriptive list provides customers with incentive values for various efficiency improvement projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable kW removed. New construction rebates are available on savings over code plus bonus rebates for Leadership in Energy & Environmental Design (LEED) certification. The maximum annual incentive per facility is $50,000. Customers can receive multi-year incentives in a single year when such multiyear incentives do not exceed the aggregate of $100,000 per facility and no incentive was provided in the immediately preceding year. The program is applicable for combined prescriptive, custom and new construction rebates.

LG&E/KU eliminated the on-site commercial audits from this program, but provide a rebate to commercial customers who have an independent third-party on-site commercial audit performed and verify that they have implemented the recommended energy-saving measures from the audit. LG&E/KU also implemented an online tool for their Business Service Centers and commercial customer segment to provide recommendations for EE improvements. This enhancement will allow the Companies to provide EE programming to these customers and further support customer goals. The intent is to encourage new construction efforts to implement design options for efficient construction that is above building code that will further increase energy savings.

5. Residential Conservation/Home Energy Performance – This program provides a comprehensive on-site audit from a certified auditor. For a fee of $25, residential customers receive incentives to support the implementation of energy-saving measures. Customers are eligible for incentives ranging from $150 to $1,000

[83] *Id.* at 28.

based on EE measures that are purchased and installed and validated through a follow-up test.

LG&E/KU enhanced this program with a multi-family property incentive tier in order to capture energy saving in a multi-family environment. The insulation and weatherization tier is targeted to implementation of insulation and weatherization measures identified in the completed onsite audit reports. The participation goals are unchanged and there are no energy or demand reductions expected.

NEW DSM/EE PROGRAMS

LG&E/KU is offering a new voluntary Advanced Metering Systems ("AMS") program. The offering is limited to 5,000 LG&E and 5,000 KU residential and general service customers on a first-come-first-served basis, and will include a web portal to display consumption data to customers. The primary purpose of the AMS is to put in place the communications and control infrastructure necessary for possible future advanced-meter deployments, as well as to provide participating customers more detailed information about their consumption. The Companies stated in their application that their proposal was consistent with KRS 278.285(1)(h), which includes among the factors to be considered when the Commission undertakes a review of a utility's proposed DSM/EE plan, "Next-generation residential utility meters that can provide residents with amount of current utility usage, its cost, and can be capable of being read by the utility either remotely or from the exterior of the home." LG&E/KU has indicated the advanced meters they plan to deploy as part of the proposed AMS are precisely such meters. Through the AMS, the Companies would remotely read participating customers' meters and provide the customers with hourly energy usage data using a website portal, according to the Companies, with a customer's data available on the website within 48 hours of collection. The Companies stated that the benefits are unknown and will depend on what customers do with the enhanced consumption information from the advanced meters and the associated portal.

The proposed costs of the AMS are $5.7 million[84] for 2015-2018, which includes $3.8 million in capital costs and $1.9 million for operation and maintenance costs. The Companies noted that they have been engaged with various stakeholders since 2007 in considering the potential benefits and costs of Advanced Metering Infrastructure ("AMI") or smart-meter deployment and related service offerings. LG&E stated that it conducted a Responsive Pricing Program and Smart Meter Pilot from 2008-2011 to test certain smart meters and pricing alternatives in a geographically targeted area. The study tested the functionality of equipment available at that time and provided findings regarding customer engagement with rate and enabling technology options. The findings were presented to the Commission in a final report in July 2011. Subsequently, LG&E requested cancelation of the program, citing equipment obsolescence, termination of the vendor providing hosting service, and increasing costs for a decreasing number of participants. In approving the cancellation, the Commission's

[84] *Id.* at 50.

Order encouraged ongoing study into the efficacy and potential costs and benefits of further smart-meter deployment and dynamic pricing.

LG&E/KU believe investing in AMS now is more economical than in the past due to the decline in advanced-meter costs in recent years. The Companies commissioned The Smart Meter Study conducted by DNV KEMA that suggests these costs have now decreased sufficiently to consider targeted advanced-meter deployment. LG&E/KU believe that full deployment remains uneconomical; the Companies believe that the cost decrease indicates that they should again explore this technology through voluntary customer participation for a limited number of customers.

DSM/EE PROGRAM COST-EFFECTIVENESS AND ENERGY SAVINGS

The Companies stated that, in determining the DSM/EE they proposed to extend or implement Case No. 2014-00003, they used the industry-standard cost-benefit tests set out in the California Standard Practice Manual ("California tests"). The Companies concluded that the proposed DSM/EE portfolio, taken as a whole, and excluding the proposed AMS program, passes the Participant, Utility Cost, and Total Resources Cost Tests. The Companies project that the effect of all of their past and current DSM/EE programs, as well as those in the Commission approved Proposed DSM/EE Program Plan,[85] will create a cumulative demand reduction of 500 MW and cumulative energy and gas savings of 1.6 million MWh and nearly 13.4 million CCF by 2018.

In response to the Sierra Club, LGE/KU stated they have not assumed any incremental energy savings resulting from DSM programs approved as of 2014 from 2019-2028.[86]

ENERGY EFFICIENCY POTENTIAL STUDY

In Case No. 2014-00003, the Companies provided an Energy Efficiency Potential Study ("Potential Study") prepared by The Cadmus Group, Inc. ("Cadmus").[87] The scope of the Potential Study separately assessed technical and economic potential for electricity and natural gas in the residential and commercial sectors. The Potential Study did not include any EE potential study of the industrial sector. Within each utility's sector-level assessment, the Potential Study further distinguished among market segments or business types, vintage, and applicable end uses within each. The study included six residential segments (existing and new construction for single-family, multi-

[85] Case No. 2014-00003, *Louisville Gas and Electric Company and Kentucky Utilities* (Ky. PSC Jan. 17, 2014), Application at 5.

[86] Response of LG&E/KU to the Environmental Intervenors Initial Data Request ("Environmental Intervenors Initial Request"), Item 10.

[87] Case No. 2014-00003, *Louisville Gas and Electric Company and Kentucky Utilities* (Ky. PSC Jan. 17, 2014).

family, and manufactured homes) and 22 commercial segments (11 building types within existing and new construction).

Cadmus first assessed the technical potential for 252 unique electric and 113 unique gas EE measures representing a comprehensive set of electric and natural gas EE measures applicable to local climate and customer characteristics. The Potential Study results indicate 5,390 GWh of technically feasible electric EE potential savings by 2033, the end of the 20-year planning horizon, with approximately 2,527 GWh of these resources proving cost-effective. The identified economic potential amounts to 10 percent of forecast load in 2033. The Potential Study results indicate over 96 million therms of technically feasible, natural gas EE potential by 2033. The identified economic potential of 47 million therms amounts to 16 percent of forecast load in 2033.

In the final Order in Case No 2014-00003, the Commission ordered LG&E/KU to conduct an industrial sector DSM potential study. The Companies notified[88] the Commission that they had selected Cadmus to perform the industrial DSM potential study.

GREEN ENERGY[89]

The Companies each have green energy tariffs. These tariffs allow customers to voluntarily purchase Renewable Energy Credits ("RECs"). RECs represent the beneficial environmental attributes of energy generated absent the GHG 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, 2014, through December 31, 2014, LG&E had 874 customers on Tariff SGE and purchased 13,936 RECs. For that same time period, LG&E had six customers on Tariff LGE and purchased 6,079 RECs.

[88] Letter from LG&E/KU, dated February 25, 2015, responding to Order in Case No. 2014-00003, *Louisville Gas and Electric Company and Kentucky Utilities Company* (Ky. PSC Nov. 14, 2014).

[89] Semi-Annual Report dated January 30, 2015 as required in paragraph 2 in the Final Order of Case No. 2009-00467, *Application of Kentucky Utilities Company and Louisville Gas and Electric Company to Modify their Green Energy Programs* (Ky. PSC Feb. 22, 2010).

For the period July 1, 2014, through December 31, 2014, KU had 509 customers on Tariff SGE and purchased 7,894 RECs. KU also had three customers on Tariff LGE who purchased 301 RECs. The Companies purchase RECs in-house. The Companies continue to maintain program promotion efforts.

INTERVENORS' COMMENTS

The Sierra Club filed written comments expressing their concerns as to LG&E/KU DSM/EE analyses and potential. The first concern was that LG&E/KU failed to analyze a reasonable range of alternative DSM amounts in the years after 2018. They further stated that EE is the least-cost, least-risk system resource. With an average levelized cost of roughly 2-3 cents per KWh, no emissions, and the ability to defer or avoid the need for generation and related infrastructure, EE programs are a critical part of a cost-effective utility resource mix that can lower system costs and risk, thereby reducing customer bills. The Sierra Club further stated that in LG&E/KU's most recent DSM case, the Companies found that every dollar invested in DSM resulted in approximately three dollars in energy savings.[90] The Sierra Club went on to state this Commission has observed, EE and other demand-side programs are critical resources that will "become more important and cost-effective in the future as more constraints are likely to be placed on utilities that rely significantly on coal-fired generation."[91]

The Sierra Club continued by stating the Commission's IRP rules require that utilities fully consider these critical resource options in developing their plans to meet their customers' power needs for the 15-year forecast period. Specifically, utilities must identify and describe existing DSM programs and estimate their load impact; account for existing and continuing DSM programs in their 15-year load forecast; describe DSM resources that are not already in place and are considered for inclusion in the plan; provide detailed information about each new DSM program, including the energy and peak savings and cost savings; and describe the criteria used to screen each resource alternative, including DSM.[92]

The Sierra Club stated that the Commission has adopted an IRP standard that requires each electric utility to "integrate energy efficiency resources into its plans and adopt policies establishing cost-effective energy efficiency resources with equal priority as other resource options" and, in each IRP, "fully explain its consideration of cost-effective energy efficiency resources as defined in the Commission's IRP regulation (807 KAR 5:058)."[93]

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[90] Comments of the Environmental Intervenors at 21.

[91] *Id.*

[92] *Id.*

[93] *Id.* at 22.

The Sierra Club maintains the Companies did not vary the level of DSM in any of their load forecasts beyond 2018.[94] The Sierra Club stated, "In short, the Companies did not evaluate any alternatives to the levels of DSM assumed in the 2015-2018 DSM plan approved in Case No. 2014-00003."[95]

The Sierra Club claims that this is a critical flaw, because the Companies' approved DSM plan ends in 2018. The Companies have no approved DSM plan covering 2019-2028 and they conducted no analysis for this IRP of DSM plans for 2019-2028. They further state that this leaves a gap of ten years, from 2019-2028, in which the IRP assumes no new energy savings or demand reductions from DSM.[96]

The Sierra Club states that the Companies could have evaluated DSM for 2019-2028 in a number of ways. For example, the Companies could have evaluated DSM alternatives by allowing Strategist to select DSM in blocks, similar to a supply-side resource. Although it is an inferior method, the Sierra Club states, the Companies could at least have considered and applied different levels of DSM to the load forecast. The Companies chose neither of these options. Instead, the Companies used a single, pre-determined amount of DSM, which fails to evaluate the optimal amount of DSM, especially after the Companies' DSM plan ends in 2018, according to the Sierra Club. Accordingly, the Companies failed to consider a proper range of resource portfolios and evaluate how they perform under different conditions. The Sierra Club cites 807 KAR 5:058 Section 8(2).[97]

The Sierra Club's second concern was LG&E/KU's claim that the Companies will exhaust achievable EE potential by 2018 is unfounded. The Sierra Club states that in this IRP, the Companies assume that EE and demand response grind to a halt after 2018: there is no additional energy savings or peak load reduction from EE and demand response after 2018. Across every one of the 21 scenarios, the Companies assume that it is not achievable to cost-effectively save a single, additional kilowatt hour of energy. The Companies make this remarkable assumption on the theory that "the Companies are currently on track to exhaust their achievable energy-efficiency potential by 2018."[98] The notion that the Companies will exhaust their achievable EE potential by 2018 is baseless, the Sierra Club states, adding that this view merely underscores the Companies' reluctance to aggressively pursue DSM. The Sierra Club further state there are many reasons to question the Companies' assumption that achievable EE potential will be exhausted by 2018.[99]

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94 *Id.*

95 *Id.*

96 *Id.*

97 *Id.* at 22–23.

98 *Id.* at 23.

99 *Id.*

The Sierra Club first points-out that the Companies have been achieving relatively low rates of EE compared to utilities in neighboring states that have similar electricity market characteristics, including similar prices and a similar mix of customers. Secondly, the technologies that enable energy savings—from more energy efficient light bulbs to more energy efficient appliances—are constantly evolving, so there is no reason to believe that manufacturers will cease developing EE technology in 2018.[100]

The Sierra Club's third point is that the Companies do not offer any DSM programs to industrial customers, who make up roughly one-third of the Companies' energy sales. They state that the Commission recently ordered the Companies to investigate the potential for offering a DSM program to industrial customers. The Sierra Club goes on to state that given that the Companies offer no DSM programs to the customers who are a third of the Companies' load, it is difficult to fathom how the Companies could exhaust the potential for industrial programs that have not even been offered yet. To put it differently, the Sierra Club further states that it is unclear how the Companies can exhaust potential that they have yet to even tap.[101]

The Sierra Club believes that to examine a reasonable range of DSM plans for this IRP, the Companies had several options short of commissioning a new EE potential study. The Sierra Club mentions that there are commercially available models, such as Plexos Linear Program, that the Companies could have used to develop DSM plans for 2019-2028. The Sierra Club states that these DSM programs could then either be available in Strategist as resources to select, or, at a minimum, the Companies could have applied the DSM amounts to reduce their load forecasts. The Sierra Club continues that the Companies' decision to instead assume that no new energy savings or demand reductions can be achieved after 2018 results in an unreasonably narrow range of portfolios—since all 21 scenarios use the same assumption of no incremental growth in DSM after 2018. The Sierra Club goes on to state that as a result, the Companies did not consider a meaningful variety of resource portfolios and did not evaluate them under meaningfully different conditions. The Sierra Club cites 807 KAR 5:058 Section 8(2).[102]

LG&E/KU RESPONSE

LG&E/KU believe that the 2014 IRP adequately accounts for DSM/EE. The Companies state that the 2014 IRP used the best DSM/EE data available from the Cadmus EE Potential Study filed in Case No. 2014-00003.[103] Cadmus evaluated residential and commercial DSM/EE potential in the Companies' service territories. The

[100] *Id.* at 24.

[101] *Id.*

[102] *Id.* at 24–25.

[103] Case No. 2014-00003, *Louisville Gas and Electric Company and Kentucky Utilities* (Ky. PSC Jan. 17, 2014).

Potential Study concluded that over the 20-year study period (2014-2033) there would be a range of 941 GWh to 1,478 GWh of achievable electricity savings by 2033, representing 3.9 percent to 6.1 percent of residential and commercial sales in 2033. The Potential Study noted also that, due to the Companies' active marketing, advertising efforts, and relationships with trade allies, that LG&E/KU were rapidly depleting the achievable EE potential in their service territories, and were on track to exhaust their achievable EE potential by 2018. The Companies state that their DSM-EE programs are on track to reach their forecasted achievable DSM/EE potential for the entire 20-year study period by 2018. The Companies stated that this does not mean the Companies will end their DSM-EE programs in 2018, or that they will refrain from introducing new programs. This only means that the Companies' DSM/EE portfolio is on track to achieve significant savings by 2018.[104]

LG&E/KU notes that the Potential Study's "achievable potential" is a subset of economic potential, which in turn is a subset of technical potential. Stated another way, Cadmus began by analyzing how much EE potential exists in the Companies' service territory unconstrained by economics or customer behavior. The Companies state that the Potential Study narrowed the range of potential with economic constraints, determining how much EE would be economical given the Companies' avoided costs. Finally, LG&E/KU stated that Cadmus examined the behavior of the Companies' customers, recognizing that the Companies' DSM/EE programs are voluntary, to determine how much DSM-EE programming customers are likely to consume; this is what Cadmus called "achievable potential," and it is the level of DSM/EE savings the Companies used in their 2014 IRP because it was the best information available at the time the Companies performed their IRP analyses.[105]

The Companies state that the Sierra Club is not satisfied with what LG&E/KU believe to be a reasonable, evidence-based approach. The Companies state that the Sierra Club asserts the Companies should simply have assumed additional DSM/EE-related savings in 2019 and beyond. LG&E/KU assert that the Sierra Club argues the Companies' modeling software, Strategist, should have been allowed to "select DSM as a resource,"[106] but they do not state with any specificity which DSM/EE programs Strategist should have been allowed to choose, much less how one could defend having a model simply "select" DSM/EE programming as a resource in Kentucky, a state in which customer participation in utility DSM-EE programming is voluntary. LG&E/KU also note that the Sierra Club does not propose a single DSM/EE program or technology for the Companies to implement in 2019 or beyond. The Companies state that the Sierra Club asserts that DSM-EE technology will continue to improve, and the Companies should assume in their planning savings from technologies that do not exist.[107]

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[104] Companies' Joint Reply at 8-9.

[105] *Id.* at 9-10.

[106] *Id.* at 10.

[107] *Id.*

The Companies state that they agree DSM/EE technology will continue to improve and that they will continually review new DSM/EE technologies and programs. LG&E/KU also stated that they will continue to study new DSM/EE technologies and program opportunities, and will seek to implement them to the extent they are projected to be economical under the four California Standard Practice Manual tests. LG&E/KU further state that contrary to the Sierra Club's claim, that the Companies are reluctant to aggressively pursue DSM and they have the most comprehensive and successful DSM/EE portfolio in the Commonwealth. The Companies note the recently Commission approved the Companies' 2014-2018 DSM/EE Program Plan, which contains the programs of which the Companies are currently aware that, at a portfolio level, satisfy the Commission-prescribed cost-benefit tests. The Companies believe at the time they performed their 2014 IRP analysis, there were no other programs of which the Companies were aware that would have created additional DSM/EE savings and would have passed the applicable cost-benefit tests. The Companies further state the 2014-2018 DSM/EE Program Plan is projected to achieve the Potential Study's projected DSM/EE potential through 2033 by the year 2018.[108]

Finally, concerning Sierra Club's assertion that industrial DSM/EE might produce meaningful additional capacity reductions, LG&E/KU state there are three noteworthy points. First, with respect to capacity reductions, which are the only reductions important to IRP capacity planning, the Companies state they have offered for years, curtailable service riders under which the Companies' largest industrial customers receive bill credits for being interruptible at certain levels and under certain conditions. LG&E/KU state the IRP analyses took into account the ability to curtail these customers. Second, the Companies state that they did not offer industrial DSM/EE programs at the time they performed their 2014 IRP analyses, and based on input from their industrial customers, it appeared unlikely to be economical to offer such programs during the 2014 IRP planning period. The third point is a number of the Companies' largest industrial customers have told the Companies about the customers' own EE efforts and those savings are embedded in the Companies' load forecasts in the form of reduced energy consumption. The Companies state their load forecasts use data from the EIA concerning end-use efficiency trends, which helps the Companies' IRP account for forecasted naturally occurring efficiency gains. The Companies believe by the time they perform their 2017 IRP analysis, they will have likely received results of the industrial DSM/EE potential study Cadmus will perform for the Companies' service territories, and the Companies will include any insights from that study in their 2017 IRP.[109]

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[108] *Id. at* 10-11.

[109] *Id.* at 12.

DISCUSSION OF REASONABLENESS/RECOMMENDATIONS FROM THE PREVIOUS IRP

In the 2011 IRP Staff Report, Staff made following three recommendations:[110]

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

Staff is satisfied that the Companies have continued to review new possible DSM/EE programs and seek ways to expand the current approved DSM/EE plan has evident in their last DSM application.[111] In the application, the Companies reviewed their DSM portfolio and determined some new programs needed to be proposed, while some existing programs needed to be continued with modification or terminated.

2. Staff recommended 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.

Staff is satisfied that the Companies met this recommendation through the DSM programs that educate and inform their customers as to EE and the customer's individual energy consumption and potential energy savings. The Companies make their customers aware of their DSM portfolio through mailers, bill stuffers, and various forms of media ads.

3. Staff recommended that the Companies continue to define and improve procedures to evaluate, measure, and verify ("EMV") both actual costs and benefits of energy savings based on the actual dollar savings and energy savings.

Staff is satisfied the Companies pursued EMV to a greater level in the latest DSM application by applying the California tests to their DSM/EE portfolio as a whole, and determining the DSM/EE portfolio was cost-effective. In that application, the Companies reviewed various DSM program measures for consideration.[112]

EPA CLEAN POWER PLAN

As the Commission has stated in several Orders, it believes that conservation, EE and DSM become more important and cost-effective, given expectations that more constraints will be placed upon coal-based generation. The Commission notes that on

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[110] Case No. 2011-00140, *Louisville Gas and Electric Company and Kentucky Utilities Company* (Ky. PSC Mar. 13, 2013), Staff Report at 24.

[111] Case No. 2014-00003, *Louisville Gas and Electric Company and Kentucky Utilities Company* (Ky. PSC Nov. 14, 2014).

[112] *Id.* (Ky. PSC Jan. 17, 2014), Application, Exhibit MEH-3, Appendix F.

August 3, 2015, the EPA issued, under Section 111 (d) of the Clean Air Act, its Clean Power Plan ("CPP") to reduce carbon emissions from existing power plants. The CPP includes three building blocks to guide states in developing cost-effective, long-term strategies to reduce carbon dioxide emissions.

While DSM and EE are not part of the building blocks in the EPA's CPP, DSM and EE can still be used by the states to meet its targets/goals. As part of the CPP, the EPA has created a Clean Energy Incentive Program to provide opportunities for investments in renewable energy and DSM/EE that is to deliver results in 2020 and/or 2021.

Although the Companies have a number of DSM/EE programs in place, Staff encourages the Companies, and all other electric energy providers, to continue and enhance their efforts to offer cost-effective DSM/EE programs.

RECOMMENDATIONS

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

The Companies should consider reviewing industrial DSM programs, once the industrial potential study is completed, that might meet the EE needs of their industrial customers.

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.

As required by the IRP regulation (807 KAR 5:058), the Companies should 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.

Staff recommends that the Companies model for growth from new customers that participate in existing plans, considering Low, Mid and High scenarios, for potential EE from any considered new DSM/EE programs or portfolio.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

INTRODUCTION

This section summarizes, reviews, and comments on LG&E/KU's evaluation of existing and future supply-side resources. It also includes discussion on various aspects of LG&E/KU's environmental compliance planning.

EXISTING CAPACITY

LG&E/KU are investor-owned generation, transmission, and distribution utilities operating as a single interconnected and centrally dispatched electric system. The Companies serve approximately 940,000 electric customers through a 27,000 mile transmission and distribution network.

The Companies' power generating system consists of 18 coal-fired units, 11 hydro units, and 20 simple-cycle combustion turbines ("SCCTs") that are largely gas fired. The coal-fired units are located at the E.W. Brown, Cane Run, Ghent, Green River, Mill Creek, and Trimble County generating stations. Several of these stations also contain SCCTs to supplement the system during peak periods. SCCTs are located at the E.W. Brown, Cane Run, Trimble County, Paddy's Run, Zorn, and Haefling generation stations. The Companies' hydro facilities are located at the Dix Dam and Ohio Falls stations. The net summer and winter generating capabilities of the Companies are shown in Table 4.1.[113]

Table 4.1, Net Capacity

	2014 Summer Net Capacity (MW)	2014/15 Winter Net Capacity (MW)
KU		
Coal	3,220	3,251
Gas	1,422	1,608
Hydro	24	24
Total	**4,685**	**4,883**
LG&E		
Coal	2,523	2,537
Gas	644	725
Hydro	54	35
Total	**3,221**	**3,297**
COMBINED		
Coal	5,742	5,787
Gas	2,086	2,333
Hydro	78	59
Total	**7,906**	**8,180**

113 IRP, Volume I at 5-3.

In January 2014, the Companies experienced its highest combined winter peak, at 7,114 MW. KUs portion of the peak was 5,068 MW.

In 2011, the Companies planned to retire 800 MW of coal-fired generation to meet the U.S.EPA's Mercury and Air Toxics Compliance ("MATS") and Ambient Air Quality Standards. It retired the Tyrone 3 plant in Versailles in 2013 and Cane Run units 4, 5, and 6 prior to mid-2015. The Companies intended to close the 163-MW Green River plant, yet with the departure of numerous coal-fired facilities regionally, it applied and received approval from the Kentucky Division of Air Quality to keep the facility generating until at least mid-2016.

The Companies constructed a 640-MW 2x1 natural gas-fired combined-cycle unit ("NGCC") at the Cane Run site in Jefferson County to fill part of the void left from earlier plant retirements. Cane Run 7 was operational in July 2015.

The Companies planned to purchase and add to its portfolio 495 MW of simple cycle combustion-turbine power at the existing LS Power Bluegrass in La Grange, Kentucky. The Companies were unable to complete this purchase when it received an unfavorable ruling from FERC in May 2012. With the evaluation of its summer 2012 load forecast, the Companies found it necessary to acquire resources as early as 2015 in order to reliably serve customers energy and capacity needs.

The Companies released an RFP in September 2012 seeking capacity and energy to meet long-term needs. In January 2014, they submitted a case to the Commission requesting a CPCN for a 700-MW NGCC at the Green River site to come on line in 2018[114] and a 10-MW solar facility to be constructed in 2016 at the E. W. Brown site.[115] During the same timeframe, the Companies received notice from nine Municipalities of their intent to withdraw their wholesale Power Agreements and the associated 325-MW load.[116] This change in events affected the Companies filed load forecast and on October 17, 2014 a revised forecast was filed in this case. At this time, the Commission was formally notified regarding the withdrawal of the Green River NGCC plant and the continued pursuit of a CPCN for the solar facility. The Commission approved construction of the E. W. Brown 10-MW Solar Facility in December 2014. The Companies existing and planned generation are listed below:

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[114] *Id.* at 6-1.

[115] Case No. 2014-00002, *Louisville Gas & Electric Company and Kentucky Utilities* (Ky. PSC Dec. 19, 2014).

[116] *See* the IC Memorandum for the September 15, 2014 IC dated September 19, 2014. Cane Run Units 4, 5, and 6 have been retired since the IRP was filed.

Table 4.2 Existing and Planned Generation[117]

PLANT	UNIT #	LOCATION	ESTABLISHED	TYPE	CAP WIN (MW)	CAP SUM (MW)
CANE RUN	4	LOUISVILLE	1962	STEAM	155	155
CANE RUN	5	LOUISVILLE	1966	STEAM	168	168
CANE RUN	6	LOUISVILLE	1969	STEAM	240	240
CANE RUN	7	LOUISVILLE	2015	TURBINE	652	640
CANE RUN	11	LOUISVILLE	1968	TURBINE	14	14
DIX DAM	1-3	BURGIN	1925	HYDRO	24	24
E W BROWN	1	BURGIN	1957	STEAM	107	106
E W BROWN	2	BURGIN	1963	STEAM	168	166
E W BROWN	3	BURGIN	1971	STEAM	414	410
E W BROWN	5	BURGIN	2001	TURBINE	130	133
E W BROWN	6	BURGIN	1999	TURBINE	171	146
E W BROWN	7	BURGIN	1999	TURBINE	171	146
E W BROWN	8	BURGIN	1995	TURBINE	128	121
E W BROWN	9	BURGIN	1994	TURBINE	138	121
E W BROWN	10	BURGIN	1995	TURBINE	138	121
E W BROWN	11	BURGIN	1996	TURBINE	128	121
E W BROWN **(future)**		BURGIN	2016	SOLAR	0	9
GHENT	1	GHENT	1974	STEAM	481	475
GHENT	2	GHENT	1977	STEAM	477	495
GHENT	3	GHENT	1981	STEAM	482	489
GHENT	4	GHENT	1984	STEAM	491	469
GREEN RIVER	3	CENTRAL CITY	1954	STEAM	71	68
GREEN RIVER	4	CENTRAL CITY	1959	STEAM	98	93
HAEFLING	1	LEXINGTON	1970	TURBINE	14	12
HAEFLING	2	LEXINGTON	1970	TURBINE	14	12
MILL CREEK	1	LOUISVILLE	1972	STEAM	303	303
MILL CREEK	2	LOUISVILLE	1974	STEAM	299	301

[117] IRP, Volume I, Table 8.(3)(b) at 8-22.

MILL CREEK	3	LOUISVILLE	1978	STEAM	394	391
MILL CREEK	4	LOUISVILLE	1982	STEAM	486	477
OHIO FALLS	1-8	LOUISVILLE	1928	HYDRO	35-54	35-54
PADDYS RUN	11	LOUISVILLE	1968	TURBINE	13	12
PADDYS RUN	12	LOUISVILLE	1968	TURBINE	28	23
PADDYS RUN	13	LOUISVILLE	2001	TURBINE	175	147
TRIMBLE COUNTY	1	Near BEDFORD	1990	STEAM	511	511
TRIMBLE COUNTY	2	Near BEDFORD	2011	STEAM	760	732
TRIMBLE COUNTY	5	Near BEDFORD	2002	TURBINE	176	157
TRIMBLE COUNTY	6	Near BEDFORD	2002	TURBINE	176	157
TRIMBLE COUNTY	7	Near BEDFORD	2004	TURBINE	176	157
TRIMBLE COUNTY	8	Near BEDFORD	2004	TURBINE	176	157
TRIMBLE COUNTY	9	Near BEDFORD	2004	TURBINE	176	157
TRIMBLE COUNTY	10	Near BEDFORD	2004	TURBINE	176	157
ZORN	1	LOUISVILLE	1969	TURBINE	16	14

The Companies continually assess their operational generating facilities through high-level condition and performance assessments. Two of the oldest coal-fired steam units currently operating in its fleet are Brown Units 1 and 2. LG&E/KU retained Black and Veatch in 2012 to perform a specific remaining-life assessment on the units and the report concluded that if maintained properly, the facilities should continue to function as designed. Subsequent testing revealed that if a chemical additive to remove mercury were added prior to and after combustion on Units 1 and 2, the units could operate within MATs guidelines with some operational limitations during peak summer conditions.[118] The viability of the plants in its fleet hinges equally on the possibility of more stringent future environmental regulations, as opposed to significant mechanical failure, causing premature plant retirement.[119]

The Companies acknowledged a necessity to acquire power in the 2015 through 2018 period to fill a short-term need prior to the departure of the municipal load. It released an RFP in May 2014 seeking proposals from respondents who could provide 100–350 MW of capacity and energy from 2015–2020. The Companies reviewed the RFP responses and addressed the need by filing a case with the Commission to

[118] LG&E/KU's Responses to Staff's Third a Request for Information ("Staff's Third Request"), Items 1 and 2.

[119] IRP, Volume I at 5-48.

purchase firm generation and capacity from Bluegrass Generation.[120] The agreement, which the Commission approved on November 24, 2014, entitles the Companies to 165 MW of firm generation capacity and output from Bluegrass Unit No. 3 from May 1, 2015, through April 30, 2019.

Table 4.3 below details the Companies' capacity forecast with the removal of the Green River NGCC and the addition of the Bluegrass Capacity purchase and tolling agreement.

Table 4.3, Summer Load Forecast (MW)[121]

	2015	2016	2017	2018	2019	2020	2025	2028
Forecast load	7,364	7,450	7,520	7,607	7,337	7,394	7,666	7,826
DSM	(336)	(365)	(394)	(423)	(406)	(406)	(406)	(406)
Net load	7,028	7,085	7,126	7,183	6,932	6,988	7,260	7,421

RELIABILITY CRITERIA

LG&E/KU's strategy is to provide electric energy services in a reliable, economic, and efficient manner. For reliability purposes, a reserve margin is the quantity of capacity in excess of that required to satisfy the projected peak load. This reserve margin is crucial to reduce risks that are posed by forced outages, transmission constraints, load forecast deviations, or other unforeseen events that prevent a utility from being able to meet its native load requirements.

Reserve margins have both physical and economic reliability guidelines. In North America, the physical reliability guideline is the "1 in 10 year loss-of-load guideline," which is designed to assume one loss-of-load event in ten years. This physical guideline may not always coincide with an optimal economic guideline. In the Companies' reserve margin analysis, an optimal planning reserve margin range took both guidelines in effect.[122]

For the 2011 IRP, the companies targeted the midpoint of a 15 to 17 percent economic reserve margin for planning purposes. The Companies commissioned a reserve margin study for planning purposes in 2014. The findings endorsed the Companies' plan based upon a 16 percent minimum reserve margin above peak load.[123] The planning study acknowledged DSM contributions to the gross load, and used the resulting net load value to develop expansion plans. As shown below, the

[120] Case No. 2014-00321, *Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Declaratory Order and Approval Pursuant to KRS 278.300 for a Capacity Purchase and Tolling Agreement* (Ky. PSC Nov. 24, 2014).

[121] Addendum, Table 1.

[122] IRP, Volume III, 2014 Reserve Margin Study, Section 3 at 9.

[123] *Id.*, Section 5.3 at 25.

base load projections remain chiefly within the reserve margin parameters through the year 2020, at which time the Companies will have long-term needs. The low-load projections indicate no need for capacity and the high-load scenario demonstrates an immediate need. The Companies observe that new capacity could not come on line prior to 2019, due to the time needed to develop, permit and construct the unit.[124] The Companies further recognize the future potential retirement of 37 GW of capacity[125] and the potential need to rely solely upon their own generation in meeting energy and capacity needs. For the above noted justifications, the Commission finds that the 16 percent planning reserve margin is reasonable.

The Companies reserve margin projections, shown in table 4.4 below, recognize the removal of the Green River NGCC, the addition of the Brown solar facility, the addition of the Bluegrass tolling purchase, and the removal of the municipal load.[126]

Table 4.4, Reserve Margin (%)

	2015	2016	2017	2018	2019	2020	2025	2028
Reserve Margin (%)								
Base Load	17.3	16.2	15.6	14.6	16.4	15.5	11.2	8.7
Low Load	23.1	22.2	21.7	20.9	23.3	22.6	19.7	18.1
High Load	12.0	10.8	10.0	9.0	10.2	9.1	3.8	0.8

SUPPLY-SIDE RESOURCES

The Companies evaluate new supply and demand-side resources to reliably meet customers future energy needs at the lowest practical cost. The resource assessment takes into account changing economic and environmental uncertainties. LG&E/KU's' resource assessment was developed using the Strategist Integrated Planning System, developed by Ventyx, which produces and ranks a number of plans that meet environmental and reliability criteria.

The Companies developed a resource plan in several steps by first examining over 50 viable generating technology possibilities and then minimizing the technologies to produce an optimal future expansion plan.

The Companies considered coal-fired, natural gas, energy-storage, waste-to-energy, renewable and nuclear technologies whose costs and performance characteristics were estimated by Burns & McDonnell.[127] The technologies were evaluated over three capital-cost scenarios, three heat-rate scenarios, three fuel

[124] Addendum at 5.

[125] Projected Eastern Interconnect generation retirements required to meet EPA guidelines. IRP, Volume III, Reserve Margin Study at 6.

[126] Addendum at 5.

[127] IRP, Volume I at 5-16.

scenarios, two CO_2 scenarios, and ten capacity-factor scenarios for a total of 540 cases. The cases were then subjected to a 10 percent Renewable Energy Credit and Investment Tax Credit scenario and another scenario which excluded credits altogether.[128] The generation technologies which passed the screening analysis are listed in Table 4.5.[129]

TABLE 4.5

Generation Technology Options
Solar
Wind
2x1 NGCC
1x1 NGCC
SCCT One Unit
SCCT Three Units

The Companies state that due to the EPA's proposed New Source Performance Standards for GHG, natural gas has become the fuel of choice for generating power. As the predominant fuel source for planning purposes, the Companies recognize supply and demand and the effect this has on the long-term price of natural gas.[130] With this caveat, the Companies developed a low, mid, and high natural gas price for its model runs. Two other factors play dominant roles; the first being native load and its effect on demand and energy and the second is pending Green House Gas ("GHG") policy decisions.[131] Due to the current GHG uncertainties, the Companies modeled two emission scenarios, as discussed in Section 2 of this Report.

Other than the solar facility under construction at the Brown site, the Companies project no construction prior to the 2019-2020 period. Table 4.6 identifies the Optimal Expansion Plan for a zero CO_2 price scenario, Table 4.7 for a mid CO_2 price, and Table 4.8 for a CO_2 Mass emission cap scenario.[132]

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[128] *Id.* at 5-15.

[129] *Id.* at 5-33.

[130] *Id.* at 5-17.

[131] *Id.* at 5-16.

[132] Addendum, Appendix B.

Table 4.6 Optimal Expansion Plan; Zero CO_2 Price Scenario

CO_2 Price	0C	0C	0C	0C	0C	0C	0C	0C	0C
Load	LL	LL	LL	BL	BL	BL	HL	HL	HL
Gas Price	LG	MG	HG	LG	MG	HG	LG	MG	HG
2014									
2015	CR7	CR7	CR7	CR7	CR7	CR7	CR7	CR7	CR7
2016	BRS	BRS	BRS	BRS	BRS	BRS	BRS	BRS	BRS
2017									
2018									
2019							2x1G(1)	2x1G(1)	2x1G(1)
2020				2x1G(1)	CTx3(1)	CTx3(1)			
2021									
2022									
2023							2x1G(1)	CTx3(1)	CTx3(1)
2024									
2025									
2026									
2027									
2028									

CO2 Price: Zero (0C) Load: Low (LL), Base (BL) Gas Price Low(LG), Mid (MG), High (HG)

Table 4.7; Optimal Expansion Plan, Mid-CO_2 Price Scenario

CO_2 Price	MC	MC	MC	MC	MC	MC
Load	LL	LL	LL	BL	BL	BL
Gas Price	LG	MG	HG	LG	MG	HG
2014						
2015	CR7	CR7	CR7	CR7	CR7	CR7
2016	BRS	BRS	BRS	BRS	BRS	BRS
2017						
2018						
2019						
2020	Ret BR 1-2	Ret BR 1-2	Ret BR 1-2	Ret BR 1-2 1x1G(1)	Ret BR 1-2 2x1G(1)	Ret BR 1-2 2x1G(1)
2021						
2022	2x1G(1)	2x1G(1)				
2023						
2024					2x1G(1)	
2025			2x1G(1)			
2026						
2027						Wind(2)
2028						2x1G(1)

CO2 Price: Mid(MC) Load: Low(LL), Base (BL) Gas Price: Low(LG), Mid(MG), High (HG)

Table 4.8 Optimal Expansion Plan, CO2 Mass Emissions Cap Scenario

CO_2 Price	CAP	CAP	CAP	CAP	CAP	0C
Load	LL	LL	LL	BL	BL	BL
Gas Price	LG	MG	HG	LG	MG	HG
2014						
2015	CR7	CR7	CR7	CR7	CR7	CR7
2016	BRS	BRS	BRS	BRS	BRS	BRS
2017						
2018						
2019				2x1G(1)		
2020	Ret BR 1-2	Ret BR 1-2	Ret BR 1-2 Wind (6)	Ret BR 1-2	Ret BR 1-2 2x1G(1)	Ret BR 1-2 2x1G(1)
2021			Wind(3)			
2022						
2023		2x1G(1)	Wind(5)			
2024	2x1G(1)					
2025						Wind(1)
2026						Wind(1)
2027			Wind(4)	2x1G(1)	2x1G(1)	Wind(3)
2028			Wind(1) Solar(1)			Wind(5) Solar(1)

CO2 price: Mid (MC) Load: Low (LL), Base (BL) Gas Price: Low(LG), Mid (MG), High (HG)

ASSESSMENT OF NON-UTILITY GENERATION – COGENERATION, RENEWABLES, AND OTHER SOURCES

According to the Companies, successful co-generation facilities are very site specific and require an industrial host operating with the appropriate technical and economic factors which allows the arrangement the ability to be cost-effective and provide a return on the investment. LG&E/KU have a tariff on file with published rate schedules for cogeneration customers with qualifying facilities to sell power back to the grid. The net-meting tariffs recognize the energy difference a customer produces versus consumes and banks any excess as a credit to be applied against the customer's future energy purchases. The Companies net metering rider limits customers to 30 kW of generating capacity.[133]

The companies currently have 206 net metering customers with capacities ranging from 0.35 kW to 30 kW. In 2013, the group produced 225 MWh in excess of their consumption.[134] Summaries of the customers that the companies have details for are listed below in Table 4.9.

[133] IRP, Volume III at 4.

[134] *Id.* at 3.

Table 4.9, Net Metering[135]

	Solar customer (#)	Solar capacity (kW)	Wind customer (#)	Wind capacity (kW)
Residential	177	625	2	5
Non-residential	22	200	2	4
Total	199	825	4	9

If an entity has more than 30 kW of capacity, the Companies provide riders on a case-by-case examination. There is currently one 50-kW hydro-customer taking advantage of the rider, and in 2013, the customer generated zero MWh in excess of their individual energy consumption.[136]

With the relatively minimal amount of net-metering energy produced in its territory, the Companies do not include net-metering generation in its planning. The Companies do not purchase power from non-utility sources,[137] and are of the opinion that the use of distributed energy resources and renewables are on the rise, yet are not currently economical in Kentucky. However, as the industry evolves and cost projections descend downward, the Companies believe that it is important to stay abreast of the development in renewables.[138]

In this belief, as discussed in the Capacity section of this IRP, the Companies will have operational a 10-MW solar facility at the E. W. Brown Station in 2016. The Companies modeled and evaluated four renewable technology options over two iterations of 540 cases. In the iteration containing an ability to sell renewable energy credits and benefit from a 10 percent investment tax credit, the modeling forecast that in a carbon-constrained environment with high fuel prices, solar–photovoltaic, wind and hydro generation were found to be among the top four least-cost technology options in 26 of the cases.[139] The Brown Solar Facility will allow the Companies' staff the opportunity to gain operational experience with solar renewables.[140]

COMPLIANCE PLANNING

Because of the competitive advantage of coal-fired electricity, Kentucky's utilities have undertaken construction projects to install extensive environmental controls to meet the requirements of a number of new EPA rules including the MATS, Cross State Air Pollution Rule, and revised National Ambient Air Quality Standards ("NAAQS") In the

[135] *Id.* at 4.

[136] *Id.*

[137] IRP, Volume I at 8-25.

[138] *Id.* at 6-38.

[139] IRP, Volume III, 2014 Resource Assessment, Table 19 at 27.

[140] LG&E/KU's Response to Staff's First Request, Item 13.

period from 2009 to 2015, LG&E and KU will have spent over $3 billion on environmental control projects, and that amount does not include the cost of constructing replacement generation for the six coal units the Companies are retiring.[141]

As part of implementing this plan, the Companies intend to monitor the development of environmental regulations and will perform studies and other activities "necessary to make decisions regarding existing and future generating resources."[142] When evaluating long-term generation options, future GHG regulations are a very important component in the consideration.[143] LG&E/KU recognize that environmental regulations of GHG may significantly impact planning for future generating resources "potentially resulting in the economic retirement of existing [coal-fired] units" and, thereby, increasing the need for additional generating resources.[144]

Chemical additive testing was conducted at the E. W. Brown Station Units 1 and 2 in March 2013 in order to indicate mercury emission and air toxic standard compliance, identify alternatives, and signal any operational limitations required. With the addition of chemical injection systems on Units 1 and 2, the units will continue their operation and be in compliance with some operational limitations during peak summer conditions.[145] Due to MATS regulation compliance, Green River units 3 and 4 require the addition of emission controls if they are operated after April of 2015; extensions of one or two years from that date could be requested. Due to a reliability issue, a one-year extension was requested to address the reliability issue until a transmission solution could be implemented.[146]

Title IV of the Clean Air Act amendments was established to reduce the adverse effects of sulfur dioxide SO_2 and nitrogen oxides NO_X emissions which are transformed into sulfates and nitrates that combine with water in the atmosphere and return to the earth as acid rain. These emission reduction requirements lead to controls that also aided in the reduction of ozone and fine particulate matter ($PM_{2.5}$).[147] To address SO_2

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141 LG&E/KU's Supplemental Response to Sierra Club's First Data Request, Item 1.14, Introduction at 3 of 28.

142 IRP, Volume I at 5-43.

143 *Id.* at 5-17.

144 *Id.* at 5-44.

145 LG&E/KU's Responses to Staff's First Request, Item 1; Staff's Second Request for Information ("Staff's Second Request"), Item 7; Staff's Third Request, Items 1 and 2; and Environmental Intervenors Second Request, Item 16.

146 LG&E/KU's Response to Staff's First Request, Item 1.

147 IRP, Volume I at 8-73; and LG&E/KU's Responses to the Environmental Intervenors First Request, Items 15, 16, and 23.

emissions the companies have constructed FGDs and related equipment on the affected generating stations which should allow for compliant emission levels to be achieved. Compliance with all of the NO_X-related regulations has been achieved at all of the companies' generating stations through the installation of advanced low NO_X burners and over fire air systems.[148]

Jefferson County, Kentucky, has been designated as a moderate NAAQS ozone nonattainment area by the EPA. With the shutdown of three coal-fired units at the Cane Run Station and two at the Duke Gallagher Station in New Albany, Indiana, ozone non-attainment is assumed to be adequately mitigated.[149]

Section 316(b) of the Clean Water Act addresses cooling water intake structures and limits their adverse environmental impact upon aquatic populations by reducing the number of fish that can be killed by impingement against, or by the entrainment in, the water source flow at the intake screens and structures. Mitigating this can be accomplished by limiting the intake water velocity and/or reducing the amount of water needed to complete the generation unit's cooling process. Other specific solutions identified by the Companies include: "cooling towers on all active units, 'helper' towers on once-thru cooling units for use during spawning season and low flow periods, fine mesh screens (1-2 mm) for water intake, fish return systems associated with the screens, and/or annual in-stream fish studies."[150] The Clean Water Act also proposes to review effluent guidelines for the steam electric industry that focus on mitigating environmental impact related to cooling water, ash residuals, coal pile runoff, air pollution control devices along with addressing effects from other waste streams.[151] The Companies continue to monitor these regulations and advise that "[t]he proposed regulations could require capital investments for treatment facilities within the time period of this IRP document."[152]

PROJECTS

Typically environmental compliance and control projects require the installation of large power-hungry electrical machinery as part of the additional process equipment. As a result there are usually efficiency penalties for the power plant associated with such projects, since the auxiliary equipment usage of power decreases the net power production of the plant.[153]

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[148] *Id.* at 8-77 through 8-81.

[149] *Id.* at 6-43 and 6-44.

[150] *Id.* at 8-88.

[151] *Id.*

[152] *Id.* at 8-89; and LG&E/KU's Responses to the Environmental Intervenors Initial Request, Item 14, and Environmental Intervenors Supplemental Request, Items 8 and 9.

[153] IRP, Volume I at 8-14; and LG&E/KU's Response to Staff's First Request, Item 18.

The Companies continue supporting GHG research efforts at the University of Kentucky's Center for Applied Energy Research through the Carbon Management Research Group (CMRG), and at the University of Texas at Austin and 3H Company.[154] As part of these efforts, a Department of Energy grant will allow for the installation of "a carbon capture slip-stream pilot demonstration system" at Kentucky Utilities' E.W. Brown plant, which will take a small portion of the flue gas and use an amine based solvent to capture CO_2. The Companies continue to support the Electric Power Research Institute's CO_2 Capture, Utilization and Storage program, which provides information about the expected cost, availability, performance, and technical challenges of a range of flue gas CO_2 capture processes.[155]

To comply with MATS emission limitations, the Companies are installing pulse jet fabric filter systems ("PJFF") on all coal-fired units with the exception of Trimble County Unit 2, which included PJFF as original equipment, and E.W. Brown Units 1 and 2, which utilize additives to assist with mercury removal.[156] Powdered activated carbon injection will be added to the dry sorbent injection systems on each unit that receives a PJFF. Mercury and acid gas emissions will be reduced further at all coal-fired units with either existing or new wet flue gas desulfurization systems.[157]

In addressing EPA coal-combustion residual regulations, the Companies continue landfill and ash pond expansion projects at the E.W. Brown, Ghent, Mill Creek, and Trimble County stations. The Companies expect the combination of coal combustion product sales and ash containment expansions to extend the life of the ponds and landfills and help to control overall generation costs.[158]

EFFICIENCY IMPROVEMENTS

The Companies explain that increased generation efficiency will be obtained by updating controls to the latest technologies, turbine overhauls and repair work, boiler tube replacements, pulverizer rebuilds, air quality control upgrades, cooling system improvements, and generator reliability improvements.[159] Current digital technologies permit more precise control of operational parameters and allow for integrated system optimization not available in older analog controls that are being replaced. In addition,

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[154] 3H Company is a clean technology company focusing on carbon-capture technology development and commercialization. It has developed patented processes using a proprietary solvent that captures CO2 much more efficiently than other currently available CO2 capture technologies.

[155] IRP, Volume I at 6-37.

[156] *Id.* at 6-41 and 6-42,

[157] *Id.* at 6-42.

[158] *Id.* at 8-10.

[159] *Id.* at 8-5.

the companies' upgrades include generator rewinds and refurbishments, degraded turbine overhauls, boiler feed pump restorations, and voltage regulator replacements.[160] Since boiler tube failures are the largest contributor to an increased forced outage rate, the Companies regard boiler tube inspection, software modeling and timely replacement a necessity to improve generator availability and efficiency. Other preventative maintenance projects completed to improve boiler and generation efficiency include precipitator upgrades and rebuilds, installing new or modifying existing burners, air compressor and air heater replacements, and improvements to condensate and feedwater equipment.[161]

GENERATION

The rehabilitation and modernization of the eight generating units at the Ohio Falls Hydroelectric Power Station is expected to increase summer net capacity output of sustainable long-term renewable generation from 48MW to 64MW.[162] In addition, efforts at improving the reliability and efficiency of renewable generation were completed with dam remediation and the complete overhauls of the Dix Dam Hydro Units 1 and 2.[163]

In 2013 Mid-Continent Independent System Operator, Inc. ("MISO") expanded its operations and raised issues concerning network reliability and the magnitude of power flowing through its existing member connections. These MISO issues raised concerns, combined with a possible multitude of nationwide coal-fired supply side retirements, required the Companies to request and receive a one-year use extension for the Green River 3 and 4 units.[164]

For modeling, the Companies use Strategist to dispatch its generating units in a least-cost manner to meet native load and evaluate the dispatching on a weekly basis.[165] Brown Unit 3 is designated in the modeling as a must-run unit based on transmission reliability requirements.[166]

Various projects and efforts have been completed to maintain coal-fired boiler reliability, availability, and efficiency due to "[c]hanges in coal supply and coal burners to

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160 *Id.* at 8-6.

161 *Id.* at 8-7 through 8-9.

162 *Id.* at 5-37.

163 *Id.*

164 LG&E/KU's Response to Staff's Second Request, Item 2.

165 LG&E/KU's Response to Environmental Intervenors Supplemental Request, Item 2.2.

166 LG&E/KU's Response to Environmental Intervenors Third Request for Information, Item 3.3.

reduce gaseous emissions" which negatively impacted boiler slagging and precipitator performance.[167] These endeavors have addressed component maintenance issues, overhauls, refurbishments and improvements to the power stations to reduce unit derates and improve overall operating efficiency.

The Companies state that they have executed significant efforts since the 2011 IRP improving reliability and maintaining efficiency of the combustion turbine fleet[168]

TRANSMISSION

The Companies are anticipating a $35 million project to eliminate a peak month overload issue and are completing a lower-cost project in order to resolve an overload condition in a portion of its transmission system which allows for the transfer of power associated with a purchase power agreement need.[169] The Companies state that interconnections with other utilities "increase the reliability of the transmission system and provide potential access to other economic and emergency generating sources for native load customers." And, specifically, allows planning to withstand "simultaneous forced outages of a generator and a transmission facility during peak conditions."[170]

DISTRIBUTION

The construction of new substations and new distribution lines has enhanced the distribution system primarily by improving service reliability, performance and quality. Projects of installing, upgrading, and replacing distribution substation transformers have been completed in order to serve new customers, improve service reliability, and to mitigate any effects on customers due to possible equipment failures. More recently, attention has shifted to reliability and aging infrastructure projects rather than capacity enhancement projects, and a total of six projects are planned for the years 2014 through 2016. The Companies' distribution transformers are now equivalent to, or better than, the efficiencies needed for DOE compliance. Also, capacitors continue to be installed, as appropriate, on the distribution system to provide the Companies more efficient use of their transmission, substation and distribution facilities.[171]

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[167] IRP, Volume I at 8-7.

[168] *Id.* at 8-11.

[169] Case No. 2014-00002, *Louisville Gas & Electric Company and Kentucky Utilities Company* (Ky. PSC Apr. 21, 2014), Application, Exhibit DSS-1 at 23; and LG&E/KU's Response to Staff's Second Request, Item 1.

[170] IRP, Volume I at 8-14 and 8-15.

[171] *Id.* at 8-15 and 8-16.

INTERVENOR COMMENTS

The Sierra Club submitted comments (which are numbered below for delineation and clarity) near the end of the IRP process which stated that:

> In particular, the IRP contains the following significant flaws:
>
> [1] The IRP uses neither economic modeling nor another mechanism to evaluate whether capital and fixed costs may render existing coal units uneconomic to operate;
>
> [2] In particular, despite anticipating that they will spend hundreds of millions of dollars on environmental capital projects, the Companies do not evaluate whether environmental capital costs will render any units uneconomic to operate;
>
> [3] The modeling results indicate Brown Unit 3 rarely is dispatched on an economic basis, and the Companies did little to evaluate whether Brown 3 would be dispatched in the absence of being designated a must-run resource;
>
> [4] The Companies likely underestimated the scenarios in which Brown Units 1 and 2 operate at such low capacity factors that they should be retired;
>
> [5] The IRP uses only one DSM forecast and fails to explore any alternative levels of DSM;
>
> [6] The IRP assumes that no additional energy savings can be achieved from DSM for an entire decade, from 2019-2028, because of the remarkable assertion that achievable energy efficiency will be exhausted by 2018; and
>
> [7] The Companies did not explore the system savings they could achieve by encouraging expanded deployment of rooftop and large-scale solar in their territories.
>
> [8] Additionally, the Companies should improve their analysis of demand-side management and renewable resources by using up-to-date information to evaluate what level of DSM and renewable resources would be most beneficial to ratepayers under a range of potential future scenarios. In place of the flawed assumption that energy efficiency gains grind to a halt in 2018, the Companies

should be considering a range of levels of DSM programs in the years after 2018.

[9] [G]iven the significant advances in wind turbine technology and the continued decline in cost, the Companies should ensure that they use up-to-date data to analyze both building new wind capacity in Kentucky and pursuing power purchase agreements with out-of-state wind resources.[172]

LG&E/KU RESPONSES TO INTERVENOR COMMENTS

The Companies responded to the Sierra Club comments two weeks later as indicated below (appropriately numbered in order to track and identify with above):

[1] [I]t would be imprudent to rely on hourly energy markets to meet customers' needs; the markets can be volatile (in terms of pricing and availability), and transmission constraints can prevent otherwise desirable energy transfers from occurring. . . . [T]he Companies do not bet the stability of their grid—they do not jeopardize providing reliable service to their customers—on the hope that economical energy will be available, . . . it would be imprudent actually to build a resource portfolio based on such a bet, . . . particularly . . . if the federal Clean Power Plan is finalized . . . because it will likely require the further retirement of significant quantities of coal-fired generation. These retirements will tend to reduce, not increase, the amount of energy available for short-term purchase. . . .[173]

[2] The Companies' 2014 IRP is the product of a process refined over nearly 20 years of IRP submissions and Staff's comments . . . therefore . . . concerning the Companies' analysis of capital and fixed operating and maintenance ('O&M') costs of existing units and the retirement of existing units, the Companies will consider performing alternative analyses for possible unit retirements in future IRP scenario modeling; indeed, the Companies already perform rigorous, time-consuming analyses of the kind suggested. . . .[174]

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172 Environmental Intervenors Comments (summary) at 2–4.

173 Companies' Joint Reply at 3 and 4.

174 *Id.* at 5.

[3] The Companies' Must-Run Constraint on Brown Unit 3 Was Reasonable. Grid stability often requires generation from the Brown Generating Station. At the time the Companies performed their 2014 IRP, it was their understanding that placing a 155 MW must-run constraint on Brown Unit 3 would best satisfy grid-stability needs. By the time of the Companies' 2017 IRP, grid-stability needs from Brown and other generating stations could change, which is neither unusual nor at odds with the snapshot nature of IRP analyses.[175]

[4] Brown Units 1 and 2 are two of the Companies' more efficient coal units from a heat rate perspective. . . . [T]he Companies do not have an ideological commitment in favor of or against any energy source or generating unit; the Companies' goal is now, and has always been, to provide safe and reliable service at the lowest reasonable cost.[176]

[5] The Companies' 2014 IRP used the best DSM-EE data available at the time of the filing (April 21, 2014) to inform the Companies' analysis: the Cadmus Energy-Efficiency-Potential Study filed in Case No. 2014-00003. . . . The study concluded that over the 20-year study period (2014-2033) there would be a range of 941 GWh to 1,478 GWh of achievable electricity savings by 2033, representing 3.9% to 6.1% of residential and commercial sales in 2033.[177]

[6] The study noted also that . . . the Companies were rapidly depleting the achievable energy efficiency potential in their service territories, and were on track to exhaust their achievable energy efficiency potential by 2018 . . . their forecasted achievable DSM-EE potential for the entire 20-year study period by 2018 . . . that does not mean the Companies will end their DSM-EE programs in 2018, or that they will refrain from introducing new programs. It means only that the Companies' DSM-EE portfolio, as recently approved by the Commission, is on track to achieve significant savings—indeed, the forecasted level of achievable savings through 2033—by 2018.[178]

[175] *Id.* at 7.

[176] *Id.*

[177] *Id.* at 8 and 9.

[178] *Id.* at 9.

[7] It is important to recall that in the Cadmus study 'achievable potential' is a subset of economic potential, which in turn is a subset of technical potential . . . Cadmus began by analyzing how much energy-efficiency potential exists in the Companies' service territory . . . Cadmus then narrowed that range of potential with economic constraints . . . the Companies' avoided costs and other relevant factors. . . . Finally, Cadmus examined the behavior of the Companies' customers . . . that is what Cadmus called 'achievable potential,' and it is the level of DSM-EE savings the Companies used. . . . Sierra Club criticizes the Companies for not adequately accounting for the potential effects of the growth of distributed solar capacity in the Companies' service territories . . . more importantly, Sierra Club's comments do not provide any indication that distributed solar capacity would be likely to have any significant impact on the Companies' IRP . . . approximately 250 residential and commercial customers with solar generation are currently participating in the Companies' net metering tariff, which has been in place for more than a decade. The total installed solar capacity for these customers is 1,254 kW . . . Peak demand in the IRP base load forecast grows by 53 MW each year on average. Therefore, it would take about 11,000 more customers with distributed solar generation to delay the need for capacity by one year . . . even making generous assumptions about distributed solar capacity . . . would not have significantly affected any scenario's results.[179]

[8] [T]he Companies . . . have proposed a significant wind-power PPA . . . and a 10 MW solar array . . . indeed, continually review new DSM-EE technologies and programs—it would nonetheless be unwise to follow any approach that would have safe and reliable service depend on technologies that are unproven or do not exist . . . . [A]t the time the Companies performed their 2014 IRP analysis there were no other programs of which the Companies were aware that would have created additional DSM-EE savings and would have passed the applicable cost-benefit tests. And the Companies' 2014-2018 DSM-EE Program Plan is projected to achieve Cadmus's projected DSM-EE potential through 2033 by the year 2018. Therefore, the Companies used the Cadmus study's achievable DSM-EE potential for

[179] *Id.* at 9, 10, 14, and 15.

> the full term of the 2014 IRP planning period (2014-2030) but accelerated the achievement. . . .[180]
>
> [9] [T]he Companies...have proposed a significant wind-power PPA. . . .[181]
>
> The first page of the IRP states explicitly that it is a snapshot view of how available technologies can meet customers' future energy needs: 'the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner.' To evaluate different generating technologies over the IRP planning period, the Companies engage a reputable third-party consultant (in this case Burns & McDonnell) to provide cost and performance data for a broad range of technologies, including wind and solar.[182]
>
> The Companies . . . used the best information available at the time the Companies performed their analyses, including the best information then available concerning wind and solar technologies.[183]

RESPONSES TO PREVIOUS IRP CASE NO. 2011-00140 RECOMMENDATIONS

- 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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[180] *Id.* at 7, 10, and 11.

[181] *Id.* at 7.

[182] *Id.* at 12–13.

[183] *Id.* at 13.

The Companies have rate schedules that allow for distributed generation to be produced by customers within the service territory as discussed below.

Both KU and LG&E have a net metering rider which provide customers with the option of generating their own electricity using renewable resources. Net metering measures the difference between the energy a customer purchases from the Companies and the amount of energy the customer generates using its own renewable energy source. Any excess power generated is "banked" as a credit to be applied against the customer's future energy purchases from the Companies. The Companies currently have 206 net metering customers with capacities ranging from 0.35 kW to 30 kW. In 2013, those customers generated 225 MWh in excess of their individual energy consumption.

In addition to the net metering rider which limit customers to 30 kW of generating capacity, the Companies also provide riders for customers with generating capacities greater than 30 kW. These riders allow for cogeneration customers with qualifying facilities to sell all or part of their excess power to the Companies. Successful cogeneration facilities are very site-specific and require an industrial host operating with the appropriate economic factors to make the arrangement cost-effective. Currently, there is one customer on this rate with 50 kW of hydro generation. In 2013, this customer generated zero MWh in excess of its individual energy consumption.

Given the very small impact of net metering customers relative to the size of the Companies' generation needs and the lack of cogeneration customers on the Companies' system, these options have not been explicitly included as resources in the resource plan. While these types of generation sources can be somewhat reliable for producing energy, they offer an uncertain contribution to meet peak demand.

No respondents to the 2012 RFP proposed a cogeneration project. In developing the optimal resource plan, a number of small technologies that could be utilized as distributed generation were considered as supply-side options. . . . These technologies can be easily scalable and therefore would be suitable for distributed generation and combined heat and power applications.

The Companies found that after evaluating the wind and solar photovoltaic options passing the supply-side screening analysis, the overall costs of renewable generation remain higher than fossil generation technologies. The Companies advise that with tax incentives and RECs, "both solar PV and wind technologies might be cost competitive at some point."[184]

- Staff 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.

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[184] IRP, Volume III at 3, 4, and 5.

The Companies' future expansion plan is highly dependent on whether there are regulations of GHG emissions on existing generating units. GHG regulation could have a significant impact on the Companies' optimal expansion plan by making low-carbon generation more competitive and potentially resulting in the economic retirement of existing units, which would accelerate the need for additional generating resources.[185]

There have been significant changes in environmental regulations in the last few years requiring compliance planning and actions on the part of the companies. A summary list of these regulations include: the Clean Water Act – 316(b) – regulating cooling water intake structures, the Clean Water Act effluent limitation guidelines, the Clean Air Interstate Rule/Cross-State Air Pollution Rule, the Hazardous Air Pollutant Regulation, the National Ambient Air Quality Standards where SO_2, NOx, Ozone, $PM/PM_{2.5}$, and CO_2 emissions are regulated, and the Coal Combustion Residuals regulation. All of these environmental regulations and their recent changes are summarized, and their planning, operational effects, and uncertainties are discussed in detail by the companies in the application.[186]

- 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.

> The reliable supply of electricity is vital to Kentucky's economy and public safety. As electricity has become a more integral part of daily routines, customers have grown to expect it to be available at all times and in all weather conditions. Louisville Gas and Electric Company . . . and Kentucky Utilities Company . . . carry generating reserves in excess of their expected peak demand in an effort to meet the needs of their customers and the communities they serve. However, customers also demand that energy is affordable, thus the Companies must balance the costs of generating capacity with the reliability benefits provided by that capacity.[187]

In the Companies' 2014 Reserve Margin Study, the Environmental Group comments of 2011 are noted and considered.

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[185] IRP, Volume I, Section 5.(6) at 44.

[186] *Id.*, Environmental Regulations – Section 6 at 39–47; Section 8.(5)(b) at 52–66; and Section 8.(5)(f) at 73–91.

[187] IRP, Volume III, 2014 Reserve Margin Study, Executive Summary at 2.

- 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.

> On June 18, 2012, the Companies sent a letter to the Executive Director of the Commission, advising of the Companies' intent to terminate the purchase agreement with Bluegrass Generation. In addition, an Informal Conference was held on June 27, 2012 to discuss this topic.[188]

The Companies further mitigated the power loss from the Bluegrass Generating Units by entering a short-term tolling agreement to acquire 165 MW of firm generation from Unit 3 from May 2015 through April 2019.[189]

DISCUSSION OF REASONABLENESS

The Companies state that this triennial IRP includes five basic components:[190]

1) A plan summary;
2) A statement of significant changes from the most recently filed IRP;
3) A 15-year load forecast;
4) A resource assessment and acquisition plan for the fifteen years covered by the IRP; and
5) A collection of basic financial information.

Based on the Companies' Application, responses and other evidence in the case record, the Staff finds and accepts that this IRP complies with the requirements in 807 KAR 5:058. It is believed the information and responses adequately address the previous recommendations and comments presented. Therefore, Staff is generally satisfied with LG&E/KU's plan and the responses contained therein.

RECOMMENDATIONS

In the last IRP, Staff recommended that LG&E/KU provide and discuss relevant information regarding various aspects of its system and how governmental agencies, customers, and non-company actions affect its system. Given the continued and accelerated changes in environmental and other policies and interests, the consideration of each of the following areas of concern must be discussed in future resource plans.

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[188] *Id.*, at 7.

[189] *See* Case No. 2014-00321, *Louisville Gas and Electric Company and Kentucky Utilities Company* (Ky. PSC Nov. 24, 2014), Order.

[190] Companies' Joint Reply at 2.

LG&E/KU should continue to discuss the existence, and promotion of any cogeneration within their service territories and any consideration given to it.

LG&E/KU should continue to provide a discussion of any distributed generation and the impact of such generation on its system.

LG&E/KU should continue to list and describe the net metering equipment and system types installed in its service territory and the impact of the system.

LG&E/KU should continue to provide a complete discussion of compliance actions and plans relating to current and pending environmental regulations in their future resource planning.

LG&E/KU should continue their consideration of the comments of any intervenor groups and detail how those comments were considered in its system planning and preparation of the next IRP.

The Environmental Protection Agency issued a proposed rule to regulate carbon dioxide emissions from electric generating units under Section 111(d) of the Clean Air Act. It is anticipated that the Brown Solar Facility will help Kentucky meet its requirements under the proposed rule. LG&E/KU is to provide a complete discussion of activities and developments related to the Brown Solar Facility and its impact.

The Companies' 2014 Reserve Margin Study indicates that a 16 percent reserve margin will be inadequate under expected future generation and transmission capacity conditions, and physical reliability guidelines. In the next IRP LG&E/KU should provide a current and appropriate reserve margin study, along with sufficient study and analysis of expected and changing future uncertainties of adequately and reliably meeting customers' needs.

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

As in the 2011 IRP, the Companies utilized the Strategist computer model to develop optimal resource plan analyses in the 2014 IRP. Strategist uses the Companies' peak and energy load forecasts and load shapes for multiple years to create typical monthly load shapes for production costing purposes. System dispatch and operation are simulated using a load duration curve production costing technique. Production costs include fuel, incremental O&M, purchase power, and emission costs, and are calculated based on inputs including generation unit and purchase power characteristics, fuel costs, and unit- or fuel-specific emissions information. All combinations of potential options are evaluated to produce a list of resource plans, subject to user specified constraints, that satisfy the Companies' minimum reserve criterion of 16 percent (above peak load after adjusting for DSM). The production cost analysis is combined with an analysis of new construction expenditures to suggest an optimal resource plan and sub-optimal resource plans based on minimizing utility cost.

The Strategist software program can be used to evaluate a single pre-specified plan or it can be used to optimize a set of resource alternatives under a pre-determined set of constraints and assumptions. Due to potential carbon constraints in the foreseeable future, the Companies are of the opinion that its system may benefit from an additional low or zero CO_2-emitting resource before it is necessary to add capacity to maintain the minimum reserve margin. As a result, Strategist program was utilized to evaluate 2x1 NGCC and wind units in the Mid CO_2 price scenarios before the capacity was needed to maintain the target reserve margin.

SENSITIVITY ANALYSES

Within the development of the optimal expansion plans, the Companies, as previously stated, considered native load (demand and energy), natural gas prices, and GHG regulations as the most important uncertainties to consider in evaluating long-term generation resources. The Companies developed expansion plans over multiple load, gas price and a two-phase CO_2 scenario as discussed earlier in this report.

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

In the optimal expansion plans for the Zero CO_2 price scenarios, in each of the Low load scenarios, the Companies have no need for additional capacity in the planning period. In the Base load scenarios, the Companies have a long-term need for capacity in 2020. With Low gas prices, 2x1 NGCC capacity (737 MW) is added in 2020, but with Mid and High gas prices, simple-cycle combustion turbine ("SCCT") capacity (3 units, 602 MW(CTx3)) is added. With Mid and High gas prices, (and no CO_2 price), the Companies' energy needs are met primarily with existing coal units and Cane Run 7; SCCT units (1 Unit, 201 MW) are added to meet the Companies' need for capacity. With Low gas prices, the production cost savings associated with NGCC capacity more than offset the NGCC unit's higher capital costs. In each of the High load scenarios, a 2x1 NGCC unit is added in 2019 and in 2027, a 2x1 NGCC is added in a Low gas scenario whereas a CTx3 is added in a the Mid and High gas scenarios to meet the need for capacity and energy.

In the optimal expansion plans for the Mid CO_2 price scenarios, as in the original IRP filing, the Brown Units 1 and 2 are assumed to be retired in 2020. In the Low load scenarios, the retirement of Brown Units 1 and 2 results in a long-term need for capacity beginning in 2025 which will be met with a 2x1 NGCC unit. With Low and Mid gas prices, a 2x1 NGCC unit is warranted in 2022 due to the benefits from low CO_2-emitting generation under Mid CO_2 prices; the production cost savings associated with the low CO_2-emitting generation more than offset the increased cost of building new generation sooner. Under a High gas scenario, capacity additions occur only as needed to meet reserve margin since the impact of High gas prices more than offsets the benefits of low CO_2-emitting generation under Mid CO_2 prices. In the Base load scenarios, the Companies have a long-term need for capacity and energy beginning in 2020 which will be met by a 1x1 NGCC unit (368 MW) in the Low gas scenario and a 2x1 NGCC unit in the Mid and High gas scenarios. Due to the different size of these units, the next need for capacity occurs in 2021 in the Low gas scenario and 2027 in the Mid and High gas scenarios. With Mid gas prices, a 2x1 NGCC unit is warranted in 2024 prior to the next need for capacity because of the benefits from low CO_2-emitting generation under Mid CO_2 prices. Also in the High gas scenario, 100 MW (2 Units) of wind capacity is added in 2027 and a 2x1 NGCC unit added in 2028.

In the optimal expansion plans for the CO_2 mass emission cap scenarios, Brown Units 1 and 2 are assumed to be retired in 2020. As in the Mid CO_2 price scenarios, NGCC is commissioned prior to the need for capacity in some of the Low and Mid gas scenarios because of the benefits of low CO_2-emitting generation more than offset the increased cost of building new generation sooner. In the Base load, Low gas scenario a 2x1 NGCC unit is added in 2019 and 2027. In the Base load, Mid gas scenario a 2x1 NCGG unit is added in 2020 and 2027. In the Base load, High gas scenario, a 2x1 NGCC is added in 2020 followed by significant renewable additions in the latter planning years including 50 MW of wind in both 2025 and 2026, 150 MW of wind in 2027, and 250 MW of wind and 50 MW of solar in 2028.

OVERALL PLAN INTEGRATION

In the Base load scenarios, considering the actual and pending changes to the Companies' generation portfolio, along with more than 400 MW of demand reduction from DSM/EE programs by 2018 and 131 MW of curtailable load from curtailable service rider customers, the Companies will have a long-term need for capacity beginning in 2020. In seven of nine Base load scenarios, this need is met by NGCC capacity because it is a low CO_2-emitting, cost-effective alternative for meeting its customers' long-term energy and capacity needs in a potentially carbon-constrained environment.

DISCUSSION OF REASONABLENESS

The Companies have endeavored to improve their integration process considering an increasing number of issues, particularly those that are being driven by environmental compliance rules. In addressing these issues in a reasonable, cost-effective manner, LG&E/KU have:

- Analyzed and determined which units are to be retired in each of the optimal expansion planning scenarios;
- Evaluated and chosen environmental controls to be installed at other units;
- Considered the new supply-side resources needed to meet future requirements considering a potentially carbon-constrained environment; and
- Expanded demand-side programs to minimize supply-side additions.

Staff is generally satisfied with LG&E/KU's analysis of the many uncertainties it will be facing over the planning period. The improvements to its load forecasting processes are vital to improving the planning necessary to meet customers load requirements and service expectations in the most cost-effective manner in both the short- and long-term planning horizon. The scope and depth of their reserve margin analysis, as well as the supply-side and demand-side screening analysis, were comprehensive and well developed.

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