Kentucky Public Service Commission

Staff Report On the 2002 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company

Case No. 2002-00367

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SECTION 1

INTRODUCTION

Administrative Regulation 807 KAR 5:058, promulgated in 1990 by the Kentucky Public Service Commission, ("Commission") established an integrated resource planning ("IRP") process that provides for regular review by the Commission Staff of the long-range resource plans of the six major electric utilities under its jurisdiction. The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electrity 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") (jointly "LG&E/KU") submitted their 2002 Joint IRP to the Commission on October 1, 2002. The IRP submitted by LG&E/KU includes the plan for meeting their customers' electricity requirements for the period 2002-2016.

LG&E and KU are investor-owned public utilities that supply electricity and natural gas to customers primarily located in Kentucky. Both are subsidiaries of LG&E Energy Corporation ("LG&E Energy"). As owners and operators of interconnected electric generation, transmission, and distribution facilities, LG&E/KU achieve economic benefits through the operation of an interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities.

Since the issuance of the Staff Report on LG&E's and KU's Joint 1999 IRP, the parent of LG&E Energy, PowerGen plc, a British utility with international operations, was acquired by E.ON AG ("E.ON") of the Federal Republic of Germany. E.ON is a gas and electric utility system with operations in several countries, both in Europe and other parts of the world. The acquisition, which was completed in July 2002, resulted in LG&E Energy becoming an indirect subsidiary of E.ON with LG&E and KU remaining subsidiaries of LG&E Energy.

LG&E supplies electricity and natural gas to customers in the Louisville, Kentucky greater metropolitan area. It provides electric service to more than 380,000 customers in Louisville and 11 surrounding counties with a total service area covering approximately 700 square miles.

KU supplies retail electricity in 77 Kentucky counties to over 475,000 customers in a service area covering roughly 6,500 non-contiguous square miles and in 5 Virginia counties. It sells wholesale electricity to 11 Kentucky municipalities, Berea College (a privately-owned utility serving the city of Berea, Kentucky) and Pitcairn, Pennsylvania.

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

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The selected plan represents the leas-cost, least risk plan for the ultimate customers served by LG&E/KU, recognizing the need to achieve a balance between the interests of ratepayers and shareholders.

The report also includes an incremental component, noting any significant changes from the Companies' most recent IRP filed in 1999.

Based on a forecasted average annual growth rate of 2.0% over the 2002-2016 forecast period, LG&E/KU will require resource additions of roughly 2,500 megawatts ("MW"). Supply-side resources included in the plan include 10 combustion turbines ("CTs") with a total capacity of 1,480 MW. Four of these would be located at LG&E's Trimble County site with the other six at greenfield sites. The resources also include 4.7 MW through greater demand-side management ("DSM") savings, a supercritical 732 MW (the LG&E/KU share would be 549 MW) coal-fired base load plant also expected to be located at LG&E's Trimble County Generating Station, and a 474 MW combined cycle CT for which a site was not designated.

The remainder of this report is organized as follows:

- Section 2, Load Forecasting, reviews LG&E/KU's projected load growth and load forecasting methodology.

- Section 3, Demand-Side Management, summarizes LG&E/KU's evaluation of DSM opportunities.

- Section 4, Supply-Side Resource Assessment, focuses on supply resources available to meet LG&E/KU's load requirements.

- Section 5, Integration and Plan Optimization, discusses LG&E/KU's overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

SECTION 2

LOAD FORECASTING

This section reviews LG&E/KU's projected load growth and load forecasting methodology. Although much progress has been made in standardizing the forecasting processes for LG&E/KU, some differences remain, especially in how data is segmented. The value gained from this distinction will be analyzed in the near future, according to the IRP. Therefore, this IRP presents separate forecasts for LG&E and KU.

Forecasting Methodology

Forecasting energy and demand is important for both the planning and control of LG&E/KU's operations. The forecast is a tool for decisions regarding construction of facilities such as power plants, transmission lines, and substations, all of which are necessary for providing reliable service. The desired outcome of the forecasting process is a reasonable estimate so that LG&E/KU's goals of providing adequate and reliable service to its customers at the lowest reasonable cost can be attained.

LG&E/KU's energy forecasting uses econometric modeling and growth outlook information collected from their largest customers. Econometric modeling satisfies two critical forecasting requirements. First, it combines economic and demographic factors that determine sales in a rational manner. This means that national economic conditions affect regional and local economic and demographic conditions. Local economic and demographic conditions contribute their own unique characteristic trends to the outlook. Together, these provide a reasoned outlook for demographic and economic growth in LG&E/KU's service territories. This widely accepted approach establishes both a base case and the basis for optimistic and pessimistic growth scenarios for sensitivity analyses of the various resource acquisition plans studied.

Second, this approach quantifies cause and effect relationships between electric sales and the national, regional, and local factors that influence their growth. The relationships will vary depending upon the jurisdiction being modeled and the class of service. For LG&E, only one jurisdiction is modeled, Kentucky-retail. KU's forecast includes three jurisdictional groups: Kentucky-retail, Virginia-retail, and wholesale sales to 11 municipal utilities in Kentucky, Berea College Utilities, and Pitcairn, Pennsylvania. Typical classes modeled include Residential, Commercial, and Industrial.

According to the IRP, the models were proven theoretically and empirically robust to explain the behavior of LG&E/KU's customer and sales data. Once econometric relationships were established, the forecast was produced using standard procedures. For both LG&E and KU, the forecast incorporates both short and long term models with the specification and length of historic data varying by class.

The modeling processes incorporate various elements of end-use forecasting, such as baseload, heating and cooling components. The extent of this modeling varies by utility and class. Energy forecasts are converted from a billed to calendar basis and inflated for company use and losses. The resulting estimate of monthly energy requirements is then associated with a typical load profile and load factor to generate annual, seasonal, and monthly peak demand forecasts for each utility and on a combined basis.

The first step in the forecasting process is to gather national, state and service territory economic and demographic data in order to specify models that describe customers' usage characteristics. Due to the strong link between growth forecasts for national and regional economies and estimates of future energy use, national economic forecast data are used. The national forecast data for both LG&E and KU was prepared by DRI-WEFA, now known as Global Insight, an economic consulting firm used by many utilities.

Key Macroeconomic Assumptions in DRI-WEFA forecast

Following is a brief review of DRI-WEFA's key assumptions in generating its trend forecast.

- The national economy suffers no major mishaps; that is, there is an environment free of exogenous shocks. Economics output grows smoothly, in the sense that actual output follows potential output relatively closely.

- DRI-WEFA's population projection is consistent with the U.S. Census Bureau's "middle" projection for the U.S. population. The projection, based on numerous assumptions about immigration, fertility and mortality rates, projects that the US population will grow an average of 0.9% annually over the fifteen year period from 2002 to 2016.

- Except for temporary spikes, the average price of foreign crude oil is expected to remain below $30 per barrel until 2015. In the long run, scarcity of resources tends to bid prices up, while new technologies tend to hold them down. In the end, scarcity will have the greater effect, with the real price of imported oil expected to increase from around $20 a barrel in 2001 to approximately $27 a barrel in 2016.

- Annual real US Gross Domestic Product is expected to average 3.2 percent growth over the fifteen-year period from 2002 to 2016.

- Inflation over the forecast period will remain moderated, averaging 2.6 percent from 2002 to 2016.

KU

For KU, national forecast data from the University of Kentucky Center for Business and Economic Research's ("UK/CBER") State Econometric Model is used. State forecasted data from the State Econometric Model are fed into the Service Territory Economic Model ("STEM") that UK/CBER produces to create system-level class forecast drivers.

Demographic trends are an important part of the forecasting process. Population and number of persons per household forecasts work together in the STEM model to create a household forecast, which is a key driver in the development of a total Kentucky retail residential customer forecast. Kentucky retail residential customers are then used to explain growth in commercial customers. Virginia residential customers are forecast similarly using Virginia data from the STEM model.

KU's forecast of long term residential sales is a function of customers by class and sales per customer by class. Total residential customers are split between Full-Electric Residential Services ("FERS") customers and Residential Service ("RS") using EPRI's Residential End-Use Energy Planning System ("REEPS") model. For both FERS and RS customers, personal income from the STEM model is used as an explanatory variable to generate long term forecasts of residential customers.

Assumptions regarding electricity and competing fuel prices are an important component in the forecast of customers by class. KU develops internal forecasts of electricity price and obtains a forecast of regional gas and oil prices from DRI-WEFA.

Industrial sales in KU's service territory are forecast as a function of Real Gross State Product, which is an output of the STEM Model for specific industries. Commercial sales forecasts are driven by the residential customer forecast and by estimates of commercial employment. Coal mining continues to be an important industry in KU's service territory. KU forecasts mining sales using data from Resource Data International.

Since retail price is important in forecasting for all customer classes, the model must make assumptions about the future retail price of electricity. The model assumes there will be no potential future rate increases for KU. There are adjustments made for fuel expenses and environmental cost recovery.

Finally, weather data is also an important aspect of forecasting electricity usage. A twenty year rolling average for both cooling and heating degree days from the National Climatic Data Center ("NCDC") is used in the modeling.

In addition to data gathered from other sources, KU also relies upon company collected reports and survey data to supplement the analysis.

Key Assumptions in KU's Forecast

The following key economic and demographic assumptions are the primary drivers of KU's Energy and Demand Forecast.

- KU's service area population will average 0.7% annual growth over the next five years, and 0.8% annual growth over the next fifteen years.
- Annual US Real Gross Domestic Product growth will average 2.0% over the next five years and 1.9% over the next fifteen years.
- Households in KU-served counties are predicted to increase at a 1.3% annual average rate over the next five years, and 1.1% over the next fifteen years.
- Future climate is reflected by the weather values averaged for the most recent twenty-year period.
- In the next five years, it is predicted that approximately 39% of new households in KU-served counties will locate in KU's service territory. Over the next fifteen years, the percentage remains 39%.
- Residential customers are predicted to increase at a 1.3% annual rate for the next five years and at a 1.0% annual rate over the next fifteen years.
- The forecast does not reflect any potential future rate actions, including but not limited to those associated with home energy assistance programs, demand side management programs, corporate actions, new federal or state regulations, or unforeseeable surcharges or surcredits.
- The nominal residential price of gas is predicted to rise at an average annual rate of 2.3% over the next five years and 1.5% over the next fifteen years. When discounted for the expected rate of future inflation, the real residential price of gas is expected to decrease.
- KU service territory industrial output is predicted to increase at a 5.3% annual rate for the next five years and 4.1% for the next fifteen years.
- KU service territory commercial employment is predicted to increase at an average annual rate of 2.3% for the next five years and 2.1% over the next fifteen years.
- West Kentucky coal production is predicted to decline at an average annual rate of 1.8% for the next five years and decline at an average annual rate of 1.1% for the next fifteen years.

LG&E

For LG&E's forecast, methodologies similar to those used in the KU forecast were used. Regional economic data and forecasts were provided by DRI-WEFA, the University of Louisville Center for Urban Economic Research ("UL/CUER"), and UK/CBER. The UL/CUER forecasts focused on the Louisville Metropolitan Area and cover each of the seven counties included in the Louisville Metropolitan Statistical Area ("MSA") and the six Kentucky counties surrounding the Louisville MSA. Customer projections were made on the basis of the regional demographic forecasts developed by UK/CBER using the STEM model. In both the UL/CUER and UK/CBER studies, DRI-WEFA's 20-year long term forecasts were used as inputs for national economic and demographic variables.

Weather data, utilizing NCDC data for a twenty-year rolling average for the Louisville, Kentucky weather station, were used in the forecasts. As was the case with KU, no general retail rate increase was assumed.

Key Assumptions in LG&E's Forecast

The following key economic and demographic assumptions were made for the primary drivers of LG&E's Energy and Demand Forecast:

- LG&E's service territory population will average 0.4% annual growth over the next five years and average 0.5% annual growth over the next fifteen years.
- LG&E service territory households will average 0.9% annual growth over the next five years and increase at a 0.8% annual rate over the fifteen-year forecast horizon.
- Real per capita personal income in the Louisville MSA will increase at an average annual growth rate of 4.2%.
- The forecast does not reflect any potential future rate actions, including by not limited to those associated with home energy assistance programs, demand side management programs, corporate actions, new federal or state regulations, or unforeseeable surcharges or surcredits.
- Trade and service industry employment in the Louisville MSA will grow at an annual average rate of 1.3%, while manufacturing employment will grow at an annual average rate of 0.3% for the next fifteen years.
- Future climate is reflected by the weather values averaged for the most recent twenty-year period.

Results

On a combined basis, energy sales are expected to grow from 30,612 Gigawatt hours ("GWh") in 2002 to 34,334 GWh in 2006, averaging 1.4 percent average annual growth. By 2016, combined sales are expected to reach 41,551 GWh, with growth averaging 2.2 percent per year over the forecast horizon.

Combined native peak demand is predicted to grow from 6,798 Megawatts ("MW") in 2002 to 7,405 Mw in 2006, an increase of 607 MW with an average annual growth rate of 2.2 percent. By 2016, combined peak demand is predicted to reach 8,937 MW, a growth of 2,039 MW with an average annual growth rate of 2.0 percent annually. On a combined basis, LG&E/KU are summer peaking. Table 2-1 summarizes LG&E/KU's combined energy and demand growth forecasts for the 2002-2006 period.

Table 2-1

Summary of Combined Company Energy and Demand Growth

Year	Combined Annual Energy Forecast (GWh)	Percent Growth in Annual Energy Sales	Combined Summer Peak Demand (MW)	Percent Growth In Summer Peak Demand
2002	30,612	2.6%	6,798	3.7%
2003	31,751	3.7%	6,895	1.4%
2004	32,691	3.0%	7,027	1.9%
2005	33,495	2.5%	7,209	2.6%
2006	34,334	2.5%	7,405	2.7%

For KU, sales are expected to grow from 19,091 Gigawatt hours ("GWh") in 2002 to 21,723 GWh in 2006, averaging 3.2 percent average annual growth. By 2016, sales are expected to reach 26,752 GWh, with growth averaging 2.5 percent per year over the forecast horizon.

For LG&E, sales are expected to grow from 11,521 GWh in 2002 to 12,611 GWh in 2006, averaging 2.2 percent average annual growth. By 2016, sales are expected to reach 14,799 GWh, with growth averaging 1.8 percent per year over the forecast horizon.

For KU, native peak demand is predicted to grow from 4,016 MW in 2002 to 4,435 Mw in 2006, reaching 5,482 MW by 2016. For LG&E, native peak demand is predicted to grow from 2,710 MW in 2002 to 2,904 MW in 2006, reaching 3,405 in 2016.

On a combined basis, sales are expected to grow from 30,612 GWh in 2002 to 34,334 GWh in 2006, averaging 1.4% annual growth. By 2016, combined sales are expected to reach 41,551 GWh, with growth averaging 2.2% per year over the period.

Combined native peak demand is predicted to grow from 6,798 MW in 2002 to 7,405 MW in 2006, an increase of 607 MW, which represents an average annual growth rate of 2.2%. By 2016, combined peak demand is predicted to reach 8,937 MW, a growth of 2,039 MW, which represents an average annual growth rate of 2.0%. On a combined basis, LG&E/KU are summer peaking.

Uncertainty Analysis

Future values of explanatory variables included in the forecasting models may vary from those used in the forecast. To address this uncertainty, LG&E/KU develop optimistic and pessimistic scenarios to support sensitivity analyses of the various acquisition plans being studied. These scenarios are based on controlling future values of the most important variables used in the forecast. DRI-WEFA provided optimistic and pessimistic forecasts for national variables, which are processed down to the state level through the UK/CBER state econometric model and then through the STEM model to produce applicable series for use in KU's or LG&E's energy forecasting models.

The most important variables over which the forecaster controls the predicted values were selected to create optimistic and pessimistic scenarios. KU sales uncertainty has been analyzed using high and low values of population, real service territory output, commercial employment, real total personal income, and the price of electricity. LG&E sales uncertainty has been analyzed using high and low values of population, real personal income, commercial employment and the price of electricity.

For KU, the long-term optimistic and pessimistic forecast of energy sales range from 28,058 GWh to 24,993 GWh in 2016 compared to a baseline forecast of 26,752 GWh. KU's optimistic and pessimistic forecasts of peak demand range from 5,749 MW to 5,121 MW in 2016, in contrast to the baseline forecast of 5,482 MW. In the near term period, to 2006, KU's optimistic and pessimistic forecasts of peak demand range from 4,521 MW to 4,374 MW, in contrast of the baseline forecast of 4,435 MW.

For LG&E, the long-term optimistic and pessimistic forecast of energy sales range from 15,350 GWh to 14,460 GWh in 2016 compared to a baseline forecast of 14,799 GWh. LG&E's optimistic and pessimistic forecasts of peak demand range from 3,532 MW to 3,327 MW in 2016, in contrast to the baseline forecast of 3,405 MW. In the near term period, to 2006, KU's optimistic and pessimistic forecasts of peak demand range from 2,944 MW to 2,874 MW, in contrast of the baseline forecast of 2,904 MW.

Discussion of Reasonableness

In general, Staff is satisfied with the forecasting of LG&E/KU. In its report on the 1999 IRP of LG&E/KU, Staff made the following recommendations relative to load forecasting for consideration by LG&E/KU in preparing their next IRP:

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

- Due to their merger and the pending PowerGen combination, LG&E/KU should continue to pursue efforts to integrate their forecasting processes and report on these efforts in their next IRP filing.

Staff is generally pleased with LG&E/KU's response to these recommendations. Given the lack of retail competition, there is not a large impact on retail customers from the wholesale competition. We urge LG&E/KU to continue monitoring this area, as well as future costs of environmental compliance. Staff is satisfied with LG&E/KU's progress in integrating their forecasts, and look forward to the analysis of the value to be gained from continuing to segment data differently for the two companies.

Intervenor Comments

The Attorney General ("AG") expressed concern that the high economic growth rates in the forecast's early years would potentially overestimate demand, given the subsequent economic downturn. LG&E/KU responded that whenever the economy begins to rebound, the growth rate is expected to be high for a period of time. These issues will be addressed formally when and if LG&E/KU request a Certificate of Public Convenience and Necessity ("CPCN") to construct additional generation facilities.

The Staff is satisfied with the load forecasting model and its results, as well as LG&E/KU's response to questions and comments regarding the forecasts. As stated above, any addition to generation will require a CPCN and, as needed, will require updated information as well.

Recommendations

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

- LG&E/KU should continue to pursue efforts to integrate their forecasting processes and report on these efforts in their next IRP filing.

- LG&E/KU should continue to refine their load forecasting models, perhaps to rely less on national macroeconomic forecasts.

SECTION 3

DEMAND SIDE MANAGEMENT

This section summarizes the DSM assessment included in LG&E/KU's 2002 IRP. According to the IRP, LG&E/KU evaluate the future electric service requirements of their customers with a balanced consideration of demand-side and supply-side resource options. LG&E/KU established a team, which included representatives of the Kentucky Division of Energy ("KDOE") and the Air Pollution Control District of Jefferson County ("APCDJC") to evaluate demand-side management ("DSM") alternatives. Alternatives were investigated and evaluated using a two-step screening process. The first step was qualitative in nature and the second step was quantitative. The remainder of this section describes the process and LG&E/KU's results in greater detail.

Qualitative Screening Process

The DSM team identified a list of 111 alternatives to be evaluated, which are summarized by customer classification in Table 3-1.

Table 3-1: Initial DSM Alternatives

The long list of alternatives by Customer Classification	KU and LG&E	LG&E Only	Total
Residential	36	5	41
Commercial	43	1	44
Industrial	26		26
Total	105	6	111

A set of criteria was defined to facilitate an objective evaluation of these alternatives. The four criteria selected were based on: (1) LG&E/KU's objective to provide low cost, reliable energy to their customers; (2) comments from the Commission Staff's Report on the previous IRP; and (3) input from APCDJC and KDOE. Weights or values were then assigned to each of the criteria, with the highest weights assigned to the criteria judged to be the most important to develop a successful DSM program. The most important criterion was the cost effectiveness of peak demand reduction. Each potential DSM option was evaluated on a scale of 1 to 4, using the following criteria: (1) Customer Acceptance, (2) Technical Reliability, (3) Cost Effectiveness of Energy Conservation, and (4) Cost Effectiveness of Peak Demand Reduction. The qualitative screening analysis produced 21 DSM options for further analysis. If any of those 21 programs went on to pass the quantitative screening process they would then be evaluated with supply-side alternatives in LG&E/KU's integrated analysis.

Quantitative Screening Results

The 21 alternatives that passed the screening process were modeled in more detail using EPRI's DSManager, a software package developed by EPS Solutions under contract with EPRI. DSManager is a screening tool that determines cost effectiveness of DSM options by modeling their costs and benefits over a period of time. It simplifies the "real world" by using a 48-day format to represent a year. There are four daily load shapes per month: (1) high weekday; (2) medium weekday; (3) low weekday; and (4) weekend. DSManager uses LG&E/KU's aggregate system load shape and utilizes marginal energy costs to estimate the change in production costs resulting from the implementation of each DSM option. A detailed production-costing model, PROSYM, was used to determine the marginal energy costs used in the DSManager evaluation.

DSManager calculates the net present value of quantifiable costs and benefits assignable to LG&E/KU and to the customers participating in a DSM program. For each DSM initiative modeled, DSManager incorporates these factors: administrative costs, participant's costs, life span of the technology, expected level of participation, expected level of free-riders, and rate schedules. DSManager calculates changes to the participant's bill, LG&E/KU's revenue, production costs, and peak demand. The present value for each DSM alternative is calculated by DSManager and reported as costs and benefits using the five "California Tests." These five tests include the participant, utility cost, ratepayer impact measure ("RIM"), total resource cost ("TRC"), and societal cost tests. LG&E/KU used only the participant and TRC tests to screen DSM options. The participant test includes changes in costs and benefits to the customer participating in the DSM program. The TRC test combines the RIM and participant tests and indicates overall benefits of the DSM option to the average customer, whereas the RIM test considers impacts to non-participants.

DSM Programs Recommended by LG&E/KU

3 of the 21 programs modeled in DSManager passed the quantitative screening process successfully. Those were: Residential New Construction; Smart Thermostat; and Gateway TOU. The Residential New Construction program, however, was the only program considered in the integrated analysis portion of the IRP where DSM programs are evaluated along with the supply-side alternatives. KU previously offered a residential new construction program, called Comfort Home, from 1995 to 2002. It was discontinued in 2002 with the intent of reviewing its as part of the total package of DSM programs for KU and LG&E. The other two programs, Smart Thermostat and Gateway TOU are load management programs. They were not incorporated in the integrated analysis since LG&E/KU already have a load management program and the two new programs are considered to provide similar benefits to the existing load management program, using different approaches. LG&E/KU have completed their first year of their direct load control load management program, which is expected to allow them to reduce peak demand by over 120 MW by 2007. Any DSM program that passes the integrated analysis, in this case Residential New Construction, would be put through a rigorous design phase and implemented as a pilot program.

Response to Staff's Report on the 1999 IRP

In its report on the 1999 IRP, Staff recommended that LG&E/KU report on efforts to evaluate support Local Integrated Resource Planning, cogeneration and distributed generation, and the statewide and regional market transformation initiatives advocated by KDOE. In this IRP, LG&E/KU state that they incorporated Staff's recommendations concerning the number of DSM technologies evaluated in the quantitative screening, including regional market transformation programs advocated by KDOE.

LG&E/KU note that they are partners in the Energy Star program, which is a joint effort by the U. S. Department of Energy and the Environmental Protection Agency. LG&E/KU have also begun to work with KDOE and others on a regional partnership that is led by KDOE to transform the market via the Energy Star awareness campaign.

LG&E/KU state that they developed a net metering tariff to encourage customers with distributed generation or cogeneration to use that generation to offset energy bills. Cogeneration and distribution generation options were evaluated within the supply-side screening and DSM screening. Of the 111 DSM alternatives included in the long list, 12 were cogeneration and/or distributed generation technologies. Of the 47 supply-side alternatives evaluated, 10 were cogeneration or distributed generation technologies.

Intervenor Comments

KDOE provided extensive comments relative to LG&E/KU's DSM efforts. While it gave LG&E/KU credit for operating their existing DSM programs in a professional and cost-effective manner, it was highly critical of LG&E/KU's phase 2 quantitative DSM screening process, concluding that the process was so biased and inaccurate that no credence could be placed in the final cost/benefit results.

KDOE offered the following specific criticisms of LG&E/KU's DSM as reflected in the 2002 IRP:

- LG&E/KU's DSM Team did not give proper consideration to data and analyses based on successful DSM programs from other parts of the country; instead, the DSM Team contended that these programs could not be cost-effective in Kentucky.

- The phase 2 quantitative analysis of DSM options was consciously or unconsciously manipulated to arrive at preordained results.

KDOE cited three specific programs to document its criticisms:

- Commercial cool roof program – KDOE objected to how LG&E/KU handled the costs of installation in and argued that LG&E/KU should have modeled other program designs that reflected different mixes of installation costs. KDOE also disagreed with LG&E/KU's reliance on the TRC and Utility Costs tests to evaluate this program and argued that the participant test results should have also been considered.

- Commercial new construction program – KDOE complained that LG&E/KU and their DSM team manipulated cost input data to ensure that it would fail the DSManager analysis. KDOE criticized LG&E/KU for ignoring the cost and benefit data supplied by KDOE representatives and for the DSM team's resistance to trying to find ways to adapt the program to match Kentucky conditions and electric rates.

- Industrial high-efficiency motor/ASD program – KDOE stated its belief that in the industrial sector, programs focusing on motors have the potential for saving energy and reducing demand. KDOE criticized LG&E/KU for designing a program which it claims could not possibly have been found cost-effective.

KDOE also took issue with the current application of the industrial class "opt out" provision contained in KRS 278.285. KDOE contends it was not the intent of the statute to allow any and every industrial customer to opt out of DSM, and that the Commission needs to clarify and "tighten up" this aspect of utility regulation. KDOE believes that most industrial customers would benefit from well-designed and well-implemented utility-sponsored DSM programs and that shortcomings of the current approach are leading to significant economic inefficiency and losses in Kentucky.

KDOE criticized LG&E/KU for not promoting the availability of the net metering tariffs they already have in place and for stating they were not offering a "Green Power" program to their customers unless it could be judged a benefit to their shareholders. It was also critical of the fact that LG&E/KU were not evaluating cofiring biomass with coal at their large base load generating stations. KDOE also expressed concern that LG&E/KU had not revised the avoided cost rate applicable to their cogeneration tariffs to include a fixed, or capacity cost component, even though they are now projecting a need for base load capacity.

In their comments in reply to KDOE's criticisms, LG&E/KU contend that KDOE's accusations are entirely unsupported and serve to highlight KDOE's "parochial reaction" to the results of their DSM analyses. LG&E/KU responded to the criticisms in each of the three cited programs. For the commercial cool roof program, LG&E/KU disagree with KDOE's assumption that changes in the cost allocation percentages would have resulted in the program passing the DSM quantitative screening. For the commercial new construction program, LG&E/KU contend that KDOE's reliance on a 1992 issues paper is not appropriate. LG&E/KU commented:

> The issues paper "proposes changing the entire infrastructure of the construction industry in our country so that the focus is not on maximizing profit and minimizing risk, but on constructing energy efficient commercial buildings. The Companies agree there are many opportunities to improve the process, but believe that the burden of changing the culture of the construction business should not rest on the shoulders of the Companies or their customers. If this were a simple matter of offering a DSM program by a regional utility, then presumably this would have occurred in the 11 years since the publication of . . . . report."

For the high-efficiency motor/ASD program, LG&E/KU state that KDOE fails to recognize the fact that industrial customers have indicated that they prefer to implement their own energy efficiency programs. Further, LG&E/KU believe that neither they nor the Commission should require industrial customers' participation in DSM programs simply because KDOE believes it knows what is best for those customers.[1]

Based on its review of the DSM issues raised by KDOE, Commission Staff concludes that, generally, LG&E/KU's analysis of DSM alternatives was appropriate. KDOE's criticisms of LG&E/KU's quantitative DSM analysis appear to be unrealistic or unsupported, as was noted in LG&E/KU's reply comments. On the matter of industrial customers' non-participation in utility-sponsored DSM programs, KDOE's concerns are not invalid; however, KRS 278.285 permits such customers to opt out in the same manner that KDOE criticizes.

Staff agrees with KDOE that LG&E/KU should do more to promote their net metering tariffs. Staff also believes that LG&E/KU should thoroughly evaluate both the possibility of offering a green power alternative to their customers and the potential for cofiring biomass with coal. In addition, Staff believes further clarification is needed on LG&E/KU's position regarding whether a capacity cost component should be included in their avoided cost calculations relative to their cogeneration tariffs.

Discussion of Reasonableness

In its report on LG&E/KU's 1999 IRP, Staff had the following recommendations relative to DSM for consideration in preparing LG&E/KU's next IRP filing:

- In their next IRP filing, LG&E/KU should reasonably expand the number of DSM technologies which receive a complete evaluation to determine if they would be cost effective.

- In their next IRP filing, LG&E/KU should report on their efforts to evaluate and support Local Integrated Resource Planning, cogeneration and distributed generation, and statewide and regional market transformation initiatives of the type advocated by KDOE.

Staff is satisfied that LG&E/KU have adequately addressed these recommendations in their 2002 IRP filing.

Staff continues to be encouraged by LG&E/KU's DSM efforts. However, while they expanded the number of DSM technologies included in the quantitative evaluation, Staff believes that, in the next IRP, LG&E/KU should carry some of the promising DSM technologies that fail to pass the qualitative screening process forward to be included in the quantitative DSM evaluation.

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[1] LG&E/KU's reply comments did not address KDOE's comments on net metering, green power, and cofiring biomass with coal.

Recommendations

Relative to the DSM efforts of LG&E/KU as reflected in the 2002 IRP, Staff makes the following recommendations:

- Prior to the next IRP filing, LG&E/KU should consider and evaluate a variety of DSM technologies, including those applicable to industrial customers, to determine if they would be cost effective. If any DSM technology applicable to industrial customers passes the qualitative and quantitative screening, LG&E/KU should approach their industrial customers to determine if there is any interest in developing the program. However, if there is no interest by the industrial customers, LG&E/KU will not be obligated to pursue the particular program.

- In their next IRP filing, if LG&E/KU have implemented the proposed Residential New Construction program, they should provide a discussion of the marketing and status of the program for each utility.

- In their next IRP filing, LG&E/KU should include for quantitative evaluation some of the promising DSM technologies that fail to pass the qualitative screening process.

- LG&E/KU's next IRP filing should include thorough evaluations of both the possibility of offering a green power alternative to their customers and the potential for cofiring biomass with coal.

- If and when they file a CPCN application for new base load generation, LG&E/KU should include a detailed written explanation of why they believe their avoided cost calculations should not be revised to include a capacity cost component.

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, including discussion of their environmental compliance planning.

Existing Capacity

LG&E/KU have 55 generating units at 14 generating stations. The majority of this capacity, 20 units at 8 stations, is coal-fired steam generation; 7 stations have CTs; and three stations have small hydroelectric plants. The newest units are four CTs presently under construction at LG&E's Trimble County station. The 2002 summer net capacity for LG&E/KU was 7,065 megawatts ("MW"), while the winter net capacity was 7,194 MW. In addition, LG&E/KU had purchase agreements in place with Electric Energy Incorporated, Owensboro Municipal Utilities and Ohio Valley Electric Corporation. Table 4-1 shows LG&E/KU's existing electric generating facilities.

Several of LG&E/KU's CT units have been in operation for over 30 years. Some of the coal-fired units are over 50 years old. These units could be uneconomical due to their high production costs, future nitrogen oxide ("NO_x") restrictions, or the risk of their failure due to age. LG&E/KU indicate that retiring some units might be economical even without a significant mechanical failure. The failure of KU's Pineville Unit 3 in November 2001 resulted in its retirement in 2002. That unit had been in service for approximately 50 years. LG&E/KU periodically review the economic value of aging units to determine when, or if, they should be retired. Table 4-2 shows the LG&E/KU units that might be considered for retirement due to their age.

Reliability Criteria

LG&E/KU indicate that a target reserve margin in the range of 13 to15% will be adequate to meet their customers' demand in a reliable manner. LG&E/KU's reserve margin study indicates that a 14% target reserve margin represents optimal system reliability and cost-effectiveness. A reserve margin is needed to have sufficient capacity available to allow for unexpected loss of generation, reduced generation capacity due to equipment problems, unanticipated load growth, variances in load due to extreme weather conditions, and disruptions in contracted purchase power. A utility's required reserve capacity can be supplied via generation or purchased power. "Reserve margin" and "capacity margin" are derived as shown immediately after Table 4-2.

Table 4-1

Kentucky Utilities and LG&E Combined Existing Generating Facilities

1	2	3	4	5	6	7		8		9	10	11
Plant Name	Unit No.	Location in Kentucky	Status	Operation Date	Facility Type	Net Capability (MW) Winter	Summer	Entitlement KU	LGE	Fuel Type	Fuel Storage Capacity	Scheduled Upgrades Derates, Retirements
Cane Run	4	Louisville	Existing	1962	Steam	155	155		100%	Coal	250,000 Tons	None
	5			1966		168	168					
	6			1969		240	240					
	11			1968	Turbine	14	14			Gas/Oil	100,000 Gals	
Dix Dam	1-3	Burgin	Existing	1925	Hydro	24	24	100%		Water	None	None
E. W. Brown	1	Burgin	Existing	1957	Steam	97	104	100%		Coal	360,000 Tons	None
	2			1963		167	168					
	3			1971		433	429					
	5			2001	Turbine	137	134	47%	53%	Gas	None	
	6			1999	Turbine	168	154	62%	38%	Gas/Oil	2,200,000 Gals	
	7			1999		168	154					
	8			1995		132	130	100%				
	9			1994		132	130					
	10			1995		132	130					
	11			1996		132	130					
Ghent	1	Ghent	Existing	1974	Steam	502	509	100%		Coal	310,000 Tons	None
	2			1977		492	494				1,000,000 Tons	Derate - 2005
	3			1981		490	496					None
	4			1984		482	467					
Green River	1	Central City	Existing	1950	Steam	22	22	100%		Coal	170,000 Tons	None
	2			1950		22	22					
	3			1954		71	68					
	4			1959		107	100					
Haefling	1	Lexington	Existing	1970	Turbine	14	12	100%		Gas/Oil	630,000 Gals	None
	2			1970		14	12					
	3			1970		14	12					
Lock 7	1-3	Burgin	Existing	1927	Hydro	Run of River Plant		Lease		Water	None	Under Review
Mill Creek	1	Louisville	Existing	1972	Steam	309	308		100%	Coal	750,000 Tons	None
	2			1974		308	306					
	3			1978		397	391					
	4			1982		492	480					
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	32	48		100%	Water	None	Rehabilitation -beg 2004
Paddy's Run	11	Louisville	Existing	1968	Turbine	13	12		100%	Gas	None	None
	12			1968		28	23					
	13			2001		175	158	47%	53%			
Pineville	3	Four Mile	Retiring	1951	Steam	0	0	100%		Coal	0 Tons (retired)	Retire - 2002
Tyrone	1	Versailles	Existing	1947	Steam	30	27	100%		Oil	514,000 Gals	None
	2			1948		33	31					
	3			1953		72	71			Coal	30,000 Tons	
Trimble County	1	Near Bedford	Existing	1990	Steam	515	515		75%	Coal	500,000 Tons	None
	5			2002	Turbine	174	155	71%	29%	Gas	None	None
	6			2002		174	155	71%	29%			
Waterside	7	Louisville	Existing	1964	Turbine	13	11		100%	Gas	None	None
	8			1964		13	11					
Zorn	1	Louisville	Existing	1969	Turbine	16	14		100%	Gas	None	None

Table 4-2: Aging Units Considered For Retirement

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2002)
Steam	Tyrone	1	27	1947	55
Steam	Tyrone	2	31	1948	54
Steam	Green River	1	22	1950	52
Steam	Green River	2	22	1950	52
CT	Waterside	7	11	1964	38
CT	Waterside	8	11	1964	38
CT	Cane Run	11	14	1968	34
CT	Paddy's Run	11	12	1968	34
CT	Paddy's Run	12	23	1968	34
CT	Zorn	1	14	1969	33
CT	Haefling	1,2,3	36	1970	32

Reserve Margin % = (Total Supply Capability – Peak Load)/ Peak Load

Capacity Margin % = (Total Supply Capability – Peak Load)/(Total Supply Capability).

Reserve margins of other Kentucky and neighboring utilities are listed below:

1. East Kentucky Power Cooperative, Inc. - 12%
2. American Electric Power - 12%
3. Cincinnati Gas and Electric - 15%

Key variables incorporated into the reserve margin analysis are: (1) the number and length of planned generating unit outages and maintenance outages; (2) generating unit forced /equivalent forced outage rates; (3) the availability of purchased power for import; (4) customers' perceived cost of un-served/emergency energy; and (5) the expected system load and load factor. Forced outages are events that require a unit to be removed from service unexpectedly and immediately. Forced outage rates are defined as the total number of forced outage hours/(total number of forced outage hours + total number of service hours). Equivalent forced outage rates are similar to forced outage rates but include hours in which the unit is able to operate but unable to operate at full load. The Strategist computer model was utilized in the evaluation and the minimization of present value of revenue requirements was used as the decision factor.

Supply-Side Evaluation

Black & Veatch supplied LG&E/KU with the majority of data used to evaluate 47 technologies. Alternatives were screened through a levelized analysis in which total costs were calculated for each alternative, at various levels of utilization, over a 30-year period and levelized to reflect uniform payment streams in each year. Levelized costs of each alternative at varying factors were then compared and the least-cost technologies for each capacity factor increment throughout the planning period were developed. Table 4-3 shows the technologies included in the screening analysis.

Table 4-3: Technologies Screened

Technology Description	Category	Sub-Category
Pumped Hydro Energy Storage - 500 MW	Storage	Hydro
Lead-Acid Battery Energy Storage - 5 MW	Storage	Battery
Compressed Air Energy Storage - 300 MW	Storage	Compressed Air
Simple Cycle GE LM6000 CT - 31 MW	Natural Gas	SCCT
Simple Cycle GE 7EA CT - 73 MW	Natural Gas	SCCT
Simple Cycle GE 7FA CT - 148 MW	Natural Gas	SCCT
Combined Cycle GE 7EA CT - 114 MW	Natural Gas	CCCT
Combined Cycle GE 7FA CT - 235 MW	Natural Gas	CCCT
Combined Cycle 2x1 GE 7FA CT - 474 MW	Natural Gas	CCCT
W 501F CT - 219 MW	Natural Gas	CCCT
Peaking Natural Gas Recip. Engine - 3@2.16 MW	Natural Gas	Other
Baseload Natural Gas Recip. Engine - 3@2.16 MW	Natural Gas	Other
Wind Energy Conversion - 10 MW	Renewable	Wind
Solar Thermal, Parabolic Trough - 80 MW	Renewable	Solar
Solar Thermal, Parabolic Dish - 1.2 MW	Renewable	Solar
Solar Thermal, Central Receiver - 10 MW	Renewable	Solar
Solar Photovoltaic - 5 MW	Renewable	Solar
Biomass (Co-fire) - 10 MW	Renewable	BioMass
Geothermal - 37.5 MW	Renewable	Geotherm
Hydroelectric	Renewable	Hydro
MSW Mass Burn - 50 MW	Waste To Energy	MSW
RDF Stoker-Fired - 50 MW	Waste To Energy	RDF
Landfill Gas IC Engine - 7.5 MW	Waste To Energy	LFG
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	Waste To Energy	TDF
Humid Air Turbine Cycle CT - 450 MW	Natural Gas	CT
Kalina Cycle CT - 275 MW	Natural Gas	CCCT
Cheng Cycle CT - 140 MW	Natural Gas	CCCT
Pressurized Fluidized Bed Combustion - 250 MW	Coal	Fluidized Bed Combusti
Phosphoric Acid Fuel Cell - 6.6 MW	Storage	Fuel Cell
Peaking Microturbine - 0.03 MW	Natural Gas	CT
Baseload Microturbine - 0.03 MW	Natural Gas	CT
Supercritical Pulverized Coal - 500 MW	Coal	Pulverized Coal
Supercritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal
Subcritical Pulverized Coal - 250 MW	Coal	Pulverized Coal
Subcritical Pulverized Coal - 500 MW	Coal	Pulverized Coal
Subcritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal
Circulating Fluidized Bed - 250 MW	Coal	Fluidized Bed Combusti
Circulating Fluidized Bed - 500 MW	Coal	Fluidized Bed Combusti
Trimble County 2 Subcritical Pulverized Coal - 472 MW	Coal	Pulverized Coal
Trimble County 2 Supercritical Pulverized Coal - 523 MW	Coal	Pulverized Coal
Ohio Falls 9 and 10	Renewable	Hydro
Trimble County CT - 148 MW	Natural Gas	SCCT
Inlet Air Cooling on TC 5&6	Natural Gas	Other
Conversion of TC 5&6 to Combined Cycle	Natural Gas	CCCT
Wind Power - Black Mountain	Renewable	Wind
Trimble County 2 Subcritical Pulverized Coal - 733 MW	Coal	Pulverized Coal
Trimble County 2 Supercritical Pulverized Coal - 732 MW	Coal	Pulverized Coal

In order to quantify the impact of uncertainties on the supply-side cost estimates, LG&E/KU conducted a sensitivity analysis as part of the screening process. The screening analysis considered capital cost, heat rate, fuel cost, and environmental costs pertaining to NO_x, sulfur dioxide (SO_2), and carbon dioxide (CO_2) as uncertainties.

Based on the results of the screening analysis, the following supply-side technologies were recommended for further evaluation in the integrated resource optimization analysis:

- Trimble County 2 Supercritical Pulverized Coal Unit
- GE 2x1 7FA Combined Cycle Combustion Turbine
- Trimble County Combustion Turbine
- Ohio Falls Units 9 and 10
- GE 7FA Simple Cycle Combustion Turbine

Table 4-4 shows LG&E/KU's planned electric generation facilities. The four CTs to be located at the Trimble site and in operation in 2004 through 2006 are presently under construction. Subsequent to filing their IRP, LG&E/KU requested and received a CPCN to construct the four CTs in Case No. 2002-00381.

Table 4-4: Future Units

1	2	3	4	5	6	7		8		9	10	11
Plant Name	Unit No.	Location in Kentucky	Status	Operation Date	Facility Type	Net Capability (MW) Winter	Summer	Entitlement KU	LGE	Fuel Type	Fuel Storage Capacity	Scheduled Upgrades Derates, Retirements
Combined Cycle 1	1	Unknown	Planned	2016	CC	579	474	Unknown		Gas	None	None
Greenfield CT	1	Unknown	Planned	2007	Turbine	181	148	Unknown		Gas	None	None
	2			2007		181	148					
	3			2012		181	148					
	4			2012		181	148					
	5			2013		181	148					
	6			2014		181	148					
Trimble County	2	Near Bedford	Planned	2008	Steam	750	732	75%		Coal	Unknown	None
	7			2004	Turbine	181	148	Unknown		Gas	None	None
	8			2004		181	148					
	9			2005		181	148					
	10			2006		181	148					

Trimble County Unit 2

LG&E/KU's IRP indicates that LG&E's Trimble County Unit 1 sales agreements with the Illinois Municipal Electric Agency ("IMEA") and the Indiana Municipal Power Agency ("IMPA") require that LG&E provide IMEA and IMPA rights of first refusal on an ownership interest in Trimble County Unit 2. LG&E entered the agreements subsequent to Case No. 9934, *A Formal Review of the Current Status of Trimble county Unit No. 1,* wherein the Commission found that the 25% of Trimble County No. 1 not dedicated to serving LG&E's native load customers could be used as its management saw fit.

This IRP provided the first knowledge to Staff that the Trimble County Unit 1 agreements had implications for a potential Trimble County Unit 2. The agreements' provisions giving IMEA and IMPA rights of first refusal on an ownership interest in a future unit raise as an issue the fact that the Commission's decision in Case No. 9934 applied only to the 25% disallowed portion of Trimble County Unit 1. Staff expects that this will likely be an issue for the Commission's consideration when LG&E files a CPCN application for a second Trimble County coal-fired unit.

Compliance Planning

Because several changes have occurred since the filing of their previous IRP, LG&E/KU performed an evaluation of various NO_x compliance options to determine whether their previously recommended plan is still the most effective plan.. The original study assumed LG&E/KU's combined allocation of NO_x allowances to be 11,875 and the mandatory compliance date to be May 1, 2003. LG&E/KU's actual final allocation of NO_x allowance allocation is 12,447 and the compliance deadline was changed to May 30, 2004. Due to these changes, the planned Selective Catalytic Reduction technology ("SCR") for KU's Brown Unit 3 will be replaced with combustion modifications. The increase in allowances and delay in the compliance deadline will allow LG&E/KU to comply through 2009 compared to 2008 in their original plan. LG&E/KU will continue to evaluate the economics of purchasing allowances versus installing a new technology.

Regarding SO_2 compliance options, LG&E/KU began to increase SO_2 removal efficiency of coal-fired units equipped with scrubbers (Ghent 1, Trimble 1, Mill Creek 1, 2, 3 and 4, Cane Run 4, 5, and 6) in 2000. LG&E met its Clear Air Act Amendments Phase II requirements and reduced emissions in 2000 and 2001 to bank allowances for future use. With KU expected to have an annual allowance shortfall of 51,000 tons in 2007, which will grow to 71,000 tons in 2016, over-scrubbing and banking excess allowances is part of LG&E/KU's compliance plan. One alternative recommended by LG&E/KU's analysis to help address this shortfall is the installation of a scrubber at KU's Ghent 2 Unit that will reduce the shortfall by about 15,000 tons per year. At this time, it is expected that any allowance deficiency will be met by purchasing allowances.

LG&E/KU's supply-side screening considered possible future CO_2 reduction requirements. To reflect the possibility of such reductions, a sensitivity analysis was included based on a possible future carbon tax of $10 per ton.

Intervenor Comments

The AG argues that LG&E/KU failed to give adequate consideration to certain resource options, hydro and wind power, low cost options competitive with coal-fired generation. He also claims that LG&E/KU's supply-side screening methodology, which gives equal weight to all capacity factors, produces results that make renewable resource options appear to be higher cost and less desirable than they actually are.

The AG expressed concern with using this IRP to justify a future CPCN request for a new coal-fired plant. He stated that such an application must stand on its own, demonstrate the capacity is needed based on a realistic reserve margin, and show that a second Trimble County coal-fired plant is the lowest cost option through a Request for Proposal ("RFP") process. The AG expressed concern that the study of aging units biased the analysis of the need for and amount of base load capacity required. He also stated that LG&E/KU's reserve margin study overstates the need for new capacity.

The AG criticized LG&E/KU's analysis of CO_2 limits, claiming it was insufficient and based on an unrealistically low estimate of a future carbon tax. He states that, by not realistically evaluating the potential impact of future CO_2 compliance, LG&E/KU's IRP produces a predictable "business-as-usual" plan to build a high CO_2 coal plant.

KDOE argued that LG&E/KU should move away from larger, centrally located generation to adding small-scale distributed generation. KDOE based much of this argument on analyses included in the 2002 publication, *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*.

LG&E/KU described issues involving the hydro and wind power developers the AG mentioned and stated that, based on developments after filing the IRP, both of the developers cited by the AG were provided their April 2003 RFP for base load capacity. In response to criticism of their supply-side analysis, LG&E/KU explained that the screening process evaluates resource options over a range of capacity factors in order to determine which resources are the least cost at various capacity factor ranges.

LG&E/KU disagreed with some aspects of the AG's comments regarding the use of this IRP in support of a future certificate application for a new Trimble County coal-fired unit. However, they agreed with the need to perform unbiased, apples-to-apples comparisons of construction costs in a future RFP evaluation.

LG&E/KU disagreed with the claim that they would consider retiring aging generating units to support the addition of new base load capacity. They stated that the IRP supports the need for new base load capacity without retiring any of their aging units. LG&E/KU described the differences between the reserve margin study performed in conjunction with this IRP and the study done for their 1999 IRP, which supported a lower reserve margin. LG&E/KU disagreed with KDOE on the advantages of distributed generation and pointed to the benefits of large-scale centrally located power plants.

On CO_2 emissions planning, LG&E/KU pointed to the many unknown factors regarding this issue, including when any requirements might be required, what form those controls might take and the value that will be put on carbon emissions. They also noted that their anticipated coal-fired unit would be a supercritical pulverized unit that would have a carbon emissions rate 16% less than their current system-wide rate.

Commission Staff agrees with LG&E/KU regarding their consideration of hydro power and wind power generation. Staff also agrees that an unbiased comparison of capacity costs will be required as part of a future RFP evaluation or CPCN application by LG&E/KU. In the event any units are retired prior to then, LG&E/KU should file in their next IRP a feasibility study regarding the decision to retire the unit(s).

On CO_2 emissions limits, Staff recognizes that there are many unknown factors at this time. However, it believes that a wider range of possible costs associated with achieving such limits should be included in LG&E/KU's next IRP. More discussion on these issues is provided in the *Recommendations* section in Section 5 of this report.

SECTION 5

INTEGRATION AND PLAN OPTIMIZATION

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

The Integration Process

LG&E/KU developed their ultimate resource assessment and acquisition plan based on minimizing expected Present Value of Revenue Requirements (PVRR) over a 30-year planning horizon. Differences were evaluated by changing assumptions and calculating total PVRR based on the changes with a smaller PVRR as the objective.

LG&E/LU's planning analysis was performed using modules of the STRATEGIST computer model. The plan includes analyses of reserve margin requirements, supply-side resources and demand-side resources. It includes sensitivity studies of 6 areas: (1) first year available for base load addition; (2) load; (3) fuel cost; (4) unit retirements; (5) capital cost of the coal unit; and (6) O & M costs of CTs and combined cycle units.

LG&E/KU's optimal target reserve margin study indicates that a target reserve margin from 13 to 15% would be optimal and adequately and reliably meet customers' current and future demand needs. The study recommended that a 14% target reserve margin be used in LG&E/KU's long-range planning studies, which is the reserve margin used in the development of the optimal long-range resource plan. This represents a change from the LG&E/KU 1999 IRP, in which the reserve margin range was 11 to 14% and 12% was recommended as the target reserve margin for planning purposes.

LG&E/KU's supply-side analysis screened more than 20 supply-side options to arrive at 5 options for analysis with STRATEGIST. Those 5 options are as follows:

Combustion Turbines at a Greenfield Site (CTs - 148 MW each)

Combustion Turbines at Trimble County (CTs - 148 MW each)

Pulverized Coal unit at Trimble County (563 MW – 75% of total)

Combined Cycle Combustion Turbine (CCs – 474 MW)

Run of River-Ohio Falls Expansion (2 MW each)

LG&E/KU did not consider purchased power for two reasons. First, dynamics of wholesale power markets make forecasting purchased power costs with any degree of certainty for more than 2 to 3 years very difficult absent a full RFP process. Second, LG&E/KU will evaluate purchased power versus capacity in a future CPCN application as in their past CPCN filings, Case Nos. 2000-00294, 2002-00029 and 2002-00381.

The detailed analysis of the supply-side options reflected cost/performance data for the CTs and CC units based on data provided by Black & Veatch. Cost/performance data for the Trimble County coal option was based on data provided by Burns & McDonnell. Cost/performance data for the Ohio Falls option is based on data provided by Voith-Siemens Hydro. The first year available for each of the options is based on LG&E/KU's experience with permitting and constructing similar projects.

Description of Results

Initial iterations of the "base case" analysis shows the need for 7 CTs in the early years of the forecast period (4 at Trimble and 3 Greenfield CTs) with the Trimble County coal unit coming on line between 2007 and 2010, with 4 additional CTs and a CC unit later, depending on the assumptions made. The base case results show installation of the Trimble County coal unit in 2007 producing the lowest PVRR ($13.805 billion over 30 years). However, given the time necessary for construction of a coal-fired unit, it was deemed nearly impossible to install a unit by 2007. In their "first year available base load addition" sensitivity analysis, LG&E/KU assumed that 2008 is the earliest that a coal-fired unit could be brought on line due to the time involved with permitting and construction. Re-running the base case based on this assumption shows that installing the Trimble County unit in 2010 has the lowest PVRR ($13.821 billion over 30-years), while installing it in 2008 results in a somewhat greater PVRR than installing it in 2010 (by $8.2 million). It also shows that installing the unit in 2009 results in a slightly greater PVRR than installing it in 2008 ($5.6 million). The magnitude of these different PVRRs is less than .6%.

Having determined that delaying the addition of the coal unit until 2010 produced the lowest PVRR, LG&E/KU performed additional sensitivity analyses to determine how other factors might influence the unit's in-service date. The first additional sensitivity analysis, using base, low, and high load forecasts continued to show a number of CTs added in the early years with the Trimble County coal unit added between 2008 and 2010. The coal unit was added in 2008 under the high load forecast and in 2010 under both the base and low load forecasts. A sensitivity analysis using base, low and high coal prices was performed to evaluate how different coal prices would impact the timing of the coal-fired unit. This analysis, while impacting the PVRR amounts, did not impact the timing of adding the coal unit. Under base, low, and high coal prices, the unit was modeled to come on line in 2010.

Although LG&E/KU have no current plans to retire any existing generating units, they do have a number of units more than 35 years old. Their relatively high production costs and the stricter 2004 NO_x emission standards will worsen the economics of operating these units. Thus, there is a potential that retiring some older units might become economical, depending on future events. For this reason, a sensitivity analysis was performed based on retiring approximately 220 MW in either 2004 or 2008. Compared to the base case, the results of this analysis result in adding the coal unit in 2009 in the case of retiring the units in 2004, and in 2008 in the case of retiring the units in 2008.

A sensitivity analysis was also conducted based on a 7% increase in the capital cost of the coal unit. Preliminary estimates provided by Burns & McDonnell reflected a cost of $1,030 per Kw of capacity. An increase of 7% reflects a cost of $1,100 per Kw. Performing the PVRR analysis at the higher capital cost increased the PVRR, but did not impact the in-service date, compared to the results from the base case.

Another sensitivity analysis, based on lower O & M costs for CT and CC options, reduces the PVRR compared to the base case, but does not alter or accelerate the in-service dates of any of the generation facilities included in the base case.

LG&E/KU's qualitative DSM analysis screened more than 100 DSM measures. The results of this screening suggested that more than 20 DSM measures should be evaluated further in a quantitative analysis. The results of the quantitative analysis indicate that 1 program, Residential New Construction, which is expected to reduce LG&E/KU's system peak demand by 2 MW in the summer of 2008, should be considered for implementation. Because the Residential New Construction program is small, it could only serve to defer construction of additional capacity, not eliminate it. Therefore, only after the optimal expansion plan was developed was the Residential New Construction program evaluated.

Based on its analyses, LG&E/KU determined that the optimal expansion plan consists of 4 Trimble CTs, added from 2004 through 2006, 3 Greenfield CTs added in 2007 and 2008, the Trimble County coal unit in 2010, 4 Greenfield CTs added from 2012 through 2014, and a CC unit in 2016. Additional consideration of the "first year available" assumption for the coal unit indicates that LG&E/KU should maintain the flexibility to install the coal unit earlier than 2010. Earlier installation was called for in the high load forecast and unit retirement sensitivities. In addition, installation of one or two of the Greenfield CTs in 2007 – 2008 could possibly be avoided with short term purchased power under the base and low load forecasts. LG&E/KU concluded that having such flexibility, while being able to delay the unit if the economics of when to install it were to change, would expose native load to less risk of higher cost generation expenses.

After developing this optimal expansion plan, LG&E/KU modeled the plan with the Residential New Construction program added to determine whether the addition of the program affected the PVRR. Based on the 30-year analysis, adding the program to the optimal expansion plan reduces the PVRR by over $2.1 million. Based on that result, LG&E/KU modified the plan described above to include the Residential New Construction program.

Discussion of Reasonableness

In its Report on LG&E/KU's 1999 IRP, Staff made the following recommendation relative to the integration process for consideration in the preparation of their next scheduled IRP.

- In the next IRP filing, LG&E/KU should discuss in significant detail their efforts to obtain OVEC capacity related to the planned closing of the Portsmouth Gaseous Diffusion Plant.

- The next IRP filing should adequately reflect the results of LG&E's Ohio Falls hydro plant rehabilitation study.

- LG&E/KU should fully evaluate the AG's contentions relative to potential biases in the optimization model, and report the results of that evaluation in the next IRP filing.

- In the next IRP, LG&E/KU should expand the discussion of environmental issues to include current plans for compliance with NO_x emissions requirements.

Staff is generally satisfied with LG&E/KU's response and believes its recommendations were adequately addressed. Staff has the following recommendations which it believes should be addressed in the next LG&E/KU IRP filing.

Recommendations

Section 4, Supply-Side Resource Assessment, included Staff's observations on issues regarding LG&E/KU's aging generating units and their planning regarding future CO_2 emiissions limits. Staff's recommendations on those issues are as follows:

- In the next IRP, a decision to retire any generating unit(s) should be supported by a feasibility study regarding the decision to retire the unit(s).

- In the next IRP, LG&E/KU should ensure that their planning adequately reflects the impact of future CO_2 emission restrictions.