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PUBLIC SERVICE
COMMISSION

Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

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State Regulation and Rates
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November 9, 2011

RE: ***Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky***
Case No. 2011-00375

Dear Mr. DeRouen:

Please find enclosed and accept for filing an original and ten (10) copies of Louisville Gas and Electric Company and Kentucky Utilities Company's Joint Response to the Commission Staff's First Information Request dated October 26, 2011, in the above-referenced docket.

Also enclosed are an original and ten (10) copies of a Joint Petition for Confidential Protection and Deviation from Filing Requirements for certain responses as identified in the petition.

Should you have any questions regarding the enclosed, please do not hesitate to contact me.

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

cc: Hon. Dennis G. Howard
Hon. Michael L. Kurtz

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATE FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION TURBINE AT THE CANE RUN GENERATING STATION AND THE PURCHASE OF EXISTING SIMPLE CYCLE COMBUSTION TURBINE FACILITIES FROM BLUEGRASS GENERATION COMPANY, LLC IN BUCKNER, KENTUCKY	))))))))))))	**CASE NO. 2011-00375**

JOINT RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY
TO THE COMMISSION STAFF'S FIRST INFORMATION REQUEST
DATED OCTOBER 26, 2011

FILED – NOVEMBER 9, 2011

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John N. Voyles, Jr.**, being duly sworn, deposes and says that he is Vice President, Transmission and Generation Services for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John N. Voyles, Jr.

John N. Voyles, Jr.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of November 2011.

Tammy J. Ely (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is Senior Vice President, Energy Services for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of November 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Marketing for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of November 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says that he is Director – Environmental Affairs for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gary H. Revlett

Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of November 2011.

Tammy J. Elzy (SEAL)

Notary Public

My Commission Expires:

November 9, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY	)	
	)	**SS:**
COUNTY OF JEFFERSON	)	

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of November 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough
Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of November 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is Director – Accounting and Regulatory Reporting for LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L. Charnas
Shannon L. Charnas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of November 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 1

Witness: John N. Voyles, Jr.

Q-1. In Case No. 2009-00198,[1] LG&E was granted a Certificate of Public Convenience and Necessity to construct a new landfill at its Cane Run Generating Station ("Project 22"). Construction of Project 22 was to be done in four phases, with the first phase to be completed in 2015. Provide the status of this project and explain how this project would be impacted should LG&E receive approval to construct a combined cycle combustion turbine ("CCCT") unit and retire Cane Run 4, 5, and 6.

A-1. Currently, LG&E has received the 401 permit from Kentucky Division of Water ("KY-DOW") and floodplain construction permits from both Metropolitan Sewer District ("MSD") and KY-DOW. LG&E continues to work with the US Army Corps of Engineers ("USACE") on the 404 permitting process. The USACE has indicated that LG&E has supplied all necessary information and outside agency collaborations to process the 404 permit application and that USACE is working on finalization of their internal support documentation before they can issue a formal permit.

Also, LG&E continues to work with the Kentucky Division of Waste Management ("KY-DWM") on the 20-year landfill permit application. LG&E, with the assistance of our design engineer, is currently working on the third set of responses from the KY-DWM related to the permit application.

The proposed equipment general arrangement plan for the natural gas combined cycle combustion turbine ("NGCC") project proposed for the site would encroach upon the footprint of the 20 year landfill proposed in Case No. 2009-00198. Based on forecasted production rates for the remaining life of Cane Run Units 4, 5 and 6, a portion of the landfill proposed in the previously referenced case number will still be needed; however, the scale of the landfill can be significantly reduced if the noted coal-fired units are retired as currently predicted. The revised smaller landfill footprint would cover less than 20 acres, but would remain within the footprint of the previously approved landfill

[1] Case No. 2009-00198, Application of Louisville Gas and Electric Company for a Certificate of Public Convenience and Necessity and Approval of its 2009 Compliance Plan for Recovery by Environmental Surcharge (Ky. PSC, December 23, 2009).

facility and allow space for the construction of the proposed NGCC within the Cane Run property. Preliminary revisions to the landfill design are being developed that will accommodate approximately five (5) years of coal combustion products ("CCP") at maximum production rate estimates and would extend between 50 and 80 feet above surrounding grade. Once final revisions are completed, it will also be necessary to modify the permit application which was previously submitted in the support of Case No. 2009-00158 to reflect the diminished space needed for the remaining coal unit operating lives.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 2

Witness: John N. Voyles, Jr.

Q-2. Refer to page 6 of the application. The cost of the proposed Cane Run natural gas combined cycle combustion turbine facility ('CR7'') is $583 million, and the cost of the proposed Bluegrass Generation acquisition is $110 million. Based upon the ownership percentages shown on paragraph 11 of page 6 of the application, it appears that KU's and LG&E's shares of the total cost of the two proposed projects will be approximately $489 million and $204 million, respectively. The cost of the expected electric transmission improvements is included in the totals.

a. Explain whether the costs for required electric transmission improvements at each facility unit are to be allocated solely by the ownership percentages of the facility.

b. Explain whether the improvements will benefit existing Cane Run units or any potential future units at Cane Run.

A-2. To clarify, there are no transmission costs included in either the $583 million CR7 project or the $110 million cost of the Bluegrass Generation acquisition. With this clarification, the following responses are provided:

a. Transmission construction costs identified in the proposed Cane Run natural gas combined cycle combustion turbine facility and the proposed Bluegrass Generation acquisition are subject to final estimation per the Open Access Transmission Tariff ("OATT") Large Generator Facility Study. Consistent with the methodology used previously by the Companies for the electric transmission system upgrades, the costs for required electric transmission improvements at each facility unit are to be allocated by the ownership percentages of the generators.

b. The transmission construction costs identified for the proposed Cane Run natural gas combined cycle combustion turbine facility and the proposed Bluegrass Generation acquisition are only necessary to support the designated resource changes for those two projects if approved by the Commission. The transmission costs estimated for these facilities do not include the transmission costs for future expansion beyond the proposed facilities nor will they result in benefits for the existing Cane Run facilities.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 3

Witness: Paul W. Thompson

Q-3. Refer to page 7 of the Direct Testimony of Paul W. Thompson where Mr. Thompson discusses future employee staffing at the Cane Run, Green River, Tyrone, and LaGrange facilities.

a. Will there be a cumulative gain or loss of permanent full-time employees at the conclusion of the facility work contained in this filing?

b. Explain whether the Bluegrass Station will be operated by relocated, permanent LG&E/KU employees.

c. What is the Bluegrass Station's anticipated staffing level and how does it compare to the current levels within the plant?

d. Describe permanent, full-time staffing for a peaking unit and how it compares to an intermediate or base-load plant.

A-3.

a. Based on the difference between coal fired units and NGCC units, there will be a cumulative reduction of permanent full-time employees at the Cane Run facility. Current staffing at Cane Run is approximately 125, and the estimated staffing level for the new NGCC is projected to range between 30 and 40 full time employees.

b. The staffing model for the Bluegrass plant is still under development, though we would anticipate offering some of the current employees operating the Bluegrass Generating units employment, bringing their experience at the station to the Companies.

c. See response to b. above.

d. Staffing for a peaking unit will vary based on its proximity to other company facilities and its projected run times. A unit near other facilities that runs infrequently would likely not be staffed with regular full-time employees, but operated by employees temporarily assigned from another location. For example, today LG&E operates the Paddy's Run peaking units from the staff at Cane Run. An isolated unit, or one that is projected to run frequently, may have a small full-time staff that is augmented as needed by other Company employees.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 4

Witness: David S. Sinclair

Q-4. Refer to the Direct Testimony of David S. Sinclair ("Sinclair Testimony") at page 4 which indicates a 1.5 percent growth rate before the impact of Demand Side Management ("DSM"). What is the projected growth rate after the impact of DSM is taken into consideration?

A-4. From 2011 to 2017, the Companies' sales after the impact of DSM are expected to grow at a compound annual growth rate of 1.1 percent. The base year for this calculation is 2011.

From 2011 to 2017, the Companies' native load demand after the impact of DSM is forecast to grow at a compound annual growth rate of 0.9 percent. The base year for this calculation is 2011.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request Dated October 26, 2011

Case No. 2011-00375

Question No. 5

Witness: David S. Sinclair

Q-5. Refer to the table on page 4 of the application and the Sinclair Testimony, page 5, lines 14-16.

a. Confirm that LG&E's and KU's forecasts show that their weather normalized peak load, after peak reductions, is projected to increase by a compound growth rate of 0.72 percent over the five-year period of 2012-2016.

b. Explain why the weather-normalized compound growth rate for the 2012-2016 forecast period exceeds the 0.4 growth rate for the five years from 2006-2010. Provide all calculations and workpapers to support the explanation.

c. Explain whether the potential de-rating of any units due to environmental remediation was considered in calculating the reserve margins. If not reflected in the reserve margins, provide the potential effects that de-rating units may have on the reserve margins.

A-5.

a. Referring to the table on page 4, the peak forecast after reductions for 2012 and 2016 are 6,821 and 7,070, respectively. The compound annual growth rate is 0.90 percent for the four-year period from 2012 to 2016. The base year for this calculation is 2012.

b. The 0.4 percent growth rate refers to the growth in peak demand before the reductions associated with interruptible demands and DSM programs. While weather is a significant factor in the actual peak numbers, economic conditions had an impact on the peak demand during the 2006-2010 period, particularly in 2008 and 2009. The load forecast assumes the resumption of modest economic growth in the 2012-2016 period. The table below shows the progression of weather-normalized peak load before the impacts of interruptible demands and DSM programs from 2006 to 2010 and the forecasted peak load from 2011 to 2016. The annual growth rate from 2006 to 2007 was 2.2%. Peak demand growth fell in 2008 and 2009 during the recession and began recovery in 2010. Note that the 2016 peak is only 135 MW greater than the weather normalized peak of 2010 which is only a 0.3% compound average growth rate over that time period.

Year*	Actual/Forecast	Combined Company Weather-Normalized Peak	% Growth in Peak Demand
2006	Actual	6,929	
2007	Actual	7,014	1.2%
2008	Actual	6,467	-7.8%
2009	Actual	6,296	-2.6%
2010	Actual	6,945	10.3%
2011	Forecast	7,091	2.1%
2012	Forecast	7,210	1.7%
2013	Forecast	7,356	2.0%
2014	Forecast	7,477	1.6%
2015	Forecast	7,603	1.7%
2016	Forecast	7,654	0.7%

c. Unit de-ratings from proposed environmental controls were included in calculating the reserve margins.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 6

Witness: David S. Sinclair

Q-6. Refer to pages 4-5 of the Sinclair Testimony in which Mr. Sinclair discusses how the joint load forecast compares to LG&E's and KU's historic load growth.

a. Provide, for LG&E and KU individually, and on a combined basis, the 2006 forecasted coincident peak load for the years 2007 through 2013.

b. Provide, for LG&E and KU individually, and on a combined basis, the 2007-2010 actual and weather-normalized coincident peak loads.

A-6.

a. Please see the table below for the KU and LG&E components of the Combined Companies' coincident peak demand before DSM (in MW).

Year	KU	LG&E	Combined Companies
2007	4,249	2,766	7,015
2008	4,363	2,829	7,192
2009	4,456	2,873	7,330
2010	4,516	2,918	7,434
2011	4,611	2,958	7,569
2012	4,651	2,997	7,648
2013	4,755	3,039	7,794

b. Please see table below for the actual and weather-normalized peak demand before DSM (in MW).

Year	KU Actual	KU Weather-Normalized	LG&E Actual	LG&E Weather-Normalized	Combined Companies Actual	Combined Companies Weather-Normalized
2007	4,387	4,219	2,883	2,795	7,270	7,014
2008	4,476	4,570	1,881	1,897	6,357	6,467
2009	4,640	4,461	1,915	1,835	6,555	6,296
2010	4,346	4,212	2,865	2,733	7,211	6,945

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 7

Witness: David S. Sinclair

Q-7. On page 5 of the Sinclair testimony, it is stated that energy forecasting is based on sales and the quantification of various variables. Explain whether off-system sales are considered as one of the energy forecasting variables.

A-7. No, off-system sales are not considered as one of the energy forecasting variables.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

**Response to the Commission Staff's First Information Request
Dated October 26, 2011**

Case No. 2011-00375

Question No. 8

Witness: David S. Sinclair

Q-8. Refer to the Sinclair Testimony at pages 7-8 and 15.

a. Provide a detailed description of the assumptions and inputs used in the 2012 joint load forecast.

b. Provide a detailed comparison of the assumptions and inputs used in the LG&E/KU 2011 Integrated Resource Plan ("IRP") and those used in the 2012 joint load forecast.

c. Explain whether the increased price of electricity, as a result of LG&E and KU passing on environmental compliance costs to ratepayers was factored into the load forecast analysis and whether this had any effect on the results.

d. The U.S. Energy Information Administration ("EIA") in its Annual Energy Outlook is forecasting the price of natural gas to be fairly low relative to historical estimates, and the current price of gas is also low. Provide a chart which shows the natural gas price forecasts used in the 2011 IRP, the 2012 load forecast and those published by the EIA.

e. Given the current and forecasted low prices of natural gas, provide, both from LG&E's and KU's and from the ratepayer's perspective, detailed explanations and cost-benefit analyses of whether it would be more advantageous for LG&E to encourage its customers (residential, commercial or industrial) to replace electric heating technology with natural gas furnaces, etc. on a going-forward basis. In addition to any other factors, the response should include which gas price forecast was used.

A-8.

a. The types of assumptions and inputs for the 2012 joint load forecast are consistent with the 2011 load forecast used for the Companies' 2011 IRP. Please refer to the IRP Volume I section 5.(2) and Volume II in Case No. 2011-00140 for descriptions of the assumptions and inputs. Please see the Companies' response to Question 8 b. for more details.

b. Not all inputs and assumptions changed since the 2011 IRP. Inputs provided by ITRON for the Statistically Adjusted End-use models are unchanged between the 2011 IRP and the 2012 joint load forecast. The 2012 joint load forecast includes an additional year of usage and weather data that is a primary input to the regression models. The methodology for developing peak demand is unchanged between the 2011 IRP and the 2012 joint load forecast. Peak demand is impacted, however, by changes to the monthly energy forecasts. Details of the peak demand forecast methodology are shown in Volume II of the 2011 IRP. Key changes in inputs and assumptions between the 2012 joint load forecast and the 2011 IRP are broken down by class below:

   Residential:
   - Electricity prices are higher in the 2012 joint load forecast.
   - Price elasticity of demand was dampened slightly based on reviewed industry studies.
   - Customer growth rates are lower in the 2012 joint load forecast based on the Companies' historical growth trends and a review of information from the Kentucky State Demographer's office, particularly for KU.
   - See attachment for details.

   Commercial:
   - Real Gross State Product (RGSP) is used as a key variable to forecast commercial sales by understanding the health of the commercial sector. The update from IHS Global Insight – US Regional Service indicates lower forecasted RGSP.
   - Electricity prices are higher in the 2012 joint load forecast.
   - Price elasticity of demand was lowered based on reviewed industry studies and discussions with small commercial customers.
   - See attachment for details.

   Industrial forecasts are developed using historical usage by rate class as well as discussions with the largest 25 customers. Non-large customer usage is forecast using historical usage minus the impact of large customers. The primary difference between the 2011 IRP and the 2012 joint load forecast is the inclusion of another year of usage information and an update of the outlook for the largest customers. The difference in energy usage for the top 25 customers between the 2011 IRP and the 2012 joint load forecast was -0.5% on average from 2011 – 2015.

c. Yes. All cost increases, including the environmental compliance costs, were factored into the load forecast through the use of elasticity of demand. As a result, price increases result in lower energy usage.

d. The attached graph shows the nominal Henry Hub gas price forecasts used in the 2011 IRP, the 2012 planning process (which includes market forward prices through

2014, as of 6/17/11 quote date), and both the 2010 and 2011 EIA Annual Energy Outlook Reference Case gas price forecasts. This information is being provided pursuant to the Companies' Petition for Confidential Protection filed contemporaneously herewith.

e. The Companies have not performed such an analysis. However, the following information factors into the Companies load forecasts. LG&E is summer--peaking, so replacing electric heating with natural gas heating in LG&E's service territory would not have any material impact on total peak load in the summer. KU has a significant amount of electric heating but it does not provide natural gas. The Companies' 2010 Appliance Saturation Survey indicates approximately 73% of LG&E customers are already using natural gas heating and only about 24% use electric heating. Around 26% of electric heating customers have an electric heat pump (which could potentially require replacement in a conversion). Residents of apartments and condominiums are the primary users of electric heat. However, these customers likely do not have the option of switching to natural gas.

KU RESIDENTIAL

	Customers		Personal Income ($)		Total HDD		Total CDD		Price Elasticity of Demand	
	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast
2011	428,733	NA	77,720	NA	4,515	NA	1,212	NA	-0.15	-0.05
2012	433,020	425,360	80,109	80,109	4,515	4,544	1,212	1,235	-0.15	-0.05
2013	437,351	428,261	82,005	82,005	4,515	4,544	1,212	1,235	-0.15	-0.05
2014	441,724	431,314	84,968	84,968	4,515	4,544	1,212	1,235	-0.15	-0.05
2015	446,141	434,410	87,621	87,621	4,515	4,544	1,212	1,235	-0.15	-0.05
2016	450,603	437,540	90,572	90,572	4,515	4,544	1,212	1,235	-0.15	-0.05
2017	455,109	440,685	93,185	93,185	4,515	4,544	1,212	1,235	-0.15	-0.05
2018	459,660	443,826	96,262	96,262	4,515	4,544	1,212	1,235	-0.15	-0.05
2019	464,257	446,959	99,157	99,157	4,515	4,544	1,212	1,235	-0.15	-0.05
2020	468,899	450,079	102,389	102,389	4,515	4,544	1,212	1,235	-0.15	-0.05
2021	473,588	453,183	105,506	105,506	4,515	4,544	1,212	1,235	-0.15	-0.05
2022	478,324	456,267	108,340	108,340	4,515	4,544	1,212	1,235	-0.15	-0.05
2023	483,107	459,324	111,023	111,023	4,515	4,544	1,212	1,235	-0.15	-0.05
2024	487,938	462,351	113,700	113,700	4,515	4,544	1,212	1,235	-0.15	-0.05
2025	492,818	465,345	116,549	116,549	4,515	4,544	1,212	1,235	-0.15	-0.05

LG&E RESIDENTIAL

	Customers		Personal Income ($)		Total HDD		Total CDD		Price Elasticity of Demand	
	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast
2011	350,540	NA	40,883	NA	4,108	NA	1,540	NA	-0.15	-0.10
2012	353,639	356,506	41,945	41,945	4,108	4,141	1,540	1,560	-0.15	-0.10
2013	356,827	359,214	42,994	42,994	4,108	4,141	1,540	1,560	-0.15	-0.10
2014	359,848	361,907	44,709	44,709	4,108	4,141	1,540	1,560	-0.15	-0.10
2015	363,093	364,529	46,326	46,326	4,108	4,141	1,540	1,560	-0.15	-0.10
2016	366,004	367,150	48,122	48,122	4,108	4,141	1,540	1,560	-0.15	-0.10
2017	369,245	369,767	49,763	49,763	4,108	4,141	1,540	1,560	-0.15	-0.10
2018	372,416	372,377	50,999	50,999	4,108	4,141	1,540	1,560	-0.15	-0.10
2019	375,716	374,975	52,714	52,714	4,108	4,141	1,540	1,560	-0.15	-0.10
2020	379,229	377,561	54,490	54,490	4,108	4,141	1,540	1,560	-0.15	-0.10
2021	382,818	380,132	55,993	55,993	4,108	4,141	1,540	1,560	-0.15	-0.10
2022	386,509	382,678	57,697	57,697	4,108	4,141	1,540	1,560	-0.15	-0.10
2023	390,036	385,199	59,539	59,539	4,108	4,141	1,540	1,560	-0.15	-0.10
2024	393,756	387,694	61,375	61,375	4,108	4,141	1,540	1,560	-0.15	-0.10
2025	397,401	390,157	63,127	63,127	4,108	4,141	1,540	1,560	-0.15	-0.10

KU COMMERCIAL

	Real Gross State Product ($mm)		Price Elasticity of Demand	
	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast
2011	168,410	NA	-0.15	-0.05
2012	175,883	174,245	-0.15	-0.05
2013	183,763	181,690	-0.15	-0.05
2014	191,791	190,403	-0.15	-0.05
2015	200,376	199,309	-0.15	-0.05
2016	209,120	207,814	-0.15	-0.05
2017	217,559	216,038	-0.15	-0.05
2018	226,305	224,401	-0.15	-0.05
2019	235,303	233,034	-0.15	-0.05
2020	244,590	242,080	-0.15	-0.05
2021	254,074	251,165	-0.15	-0.05
2022	263,927	260,590	-0.15	-0.05
2023	274,161	270,368	-0.15	-0.05
2024	284,792	280,514	-0.15	-0.05
2025	295,835	291,041	-0.15	-0.05

LG&E COMMERCIAL

	Real Gross State Product ($mm)		Price Elasticity of Demand	
	2011 IRP	2012 Joint Load Forecast	2011 IRP	2012 Joint Load Forecast
2011	168,410	NA	-0.15	-0.05
2012	175,883	174,245	-0.15	-0.05
2013	183,763	181,690	-0.15	-0.05
2014	191,791	190,403	-0.15	-0.05
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2025	295,835	291,041	-0.15	-0.05

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 9

Witness: David S. Sinclair

Q-9. Refer to the Sinclair Testimony at pages 8-9 and 15.

a. Provide an explanation of whether LG&E's natural gas sales and marketing department is aggressively pursuing a fuel-switching or duel-fuel technology or any aggressive growth strategy.

b. Provide an explanation of whether any fuel-switching or duel-fuel strategies were considered as viable demand mitigation strategies and, if not, why not.

A-9.

a. LG&E is not currently pursuing a fuel-switching or dual-fuel technology.

b. No, the Companies' peak demand occurs in the summer. Therefore, changes in winter peak due to fuel switching (using gas instead of electricity for heating) in LG&E's service territory would not change the Companies' summer peak demand.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 10

Witness: David S. Sinclair

Q-10. Refer to pages 9 and 15 of the Sinclair Testimony and the table on page 4 of the application that references a target reserve margin of 16 percent.

a. Provide the documentation supporting the development of the target 16 percent reserve margin.

b. Provide the required reserve margins for planning purposes for LG&E and KU as if they were stand-alone utilities, along with supporting documentation for those reserve margins.

c. Describe the extent to which LG&E and KU looked at multiple reserve margins higher and lower than 16 percent.

d. Provide the required reserve margins for LG&E and KU as members in the Southwest Power Pool ("SPP").

A-10.

a. Please see pages 8-118 and 8-119 in Volume I of the Companies' 2011 Integrated Resource Plan in Case No. 2011-00140. Also, please see the study titled LG&E and KU 2011 Reserve Margin Study (April 2011) in Volume III, Technical Appendix of the 2011 Integrated Resource Plan.

b. The Companies have not computed separate required reserve margins for LG&E and KU as if they were stand-alone utilities for planning purposes. LG&E and KU jointly plan and dispatch their generating units.

c. In the LG&E and KU 2011 Reserve Margin Study (April 2011), the optimal reserve margin is the reserve margin that minimizes the sum of reliability energy costs and the cost of carrying reserve capacity. This sum was evaluated over reserve margins ranging from 10 to 24 percent.

d. LG&E and KU are not members of the Southwest Power Pool Regional Transmission Organization ("RTO"). The Southwest Power Pool only serves as the Companies' Independent Transmission Operator ("ITO"). Accordingly, there are no SPP-required reserve margins for the Companies.

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Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 11

Witness: David S. Sinclair

Q-11. On page 16 of the Sinclair Testimony, it is stated that an energy and capacity Request for Proposal ("RFP") was sent to 116 potential energy suppliers. Explain how the suppliers were selected and by whom.

A-11. The selection of potential energy suppliers was the result of two efforts. First, we compiled a list of contacts for parties that have responded to past RFPs or expressed an interest in responding to future RFPs. This list included 58 different companies. Second, we compiled a list of the parties in the energy market with whom the Companies currently transact business. This list included 76 different companies. A number of companies (18) were on both lists. Therefore, the RFP was ultimately sent to 116 different companies.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 12

Witness: David S. Sinclair

Q-12. On page 17 of the Sinclair Testimony, it is stated that Phase I selection criteria included selecting the top candidates in each technology. Explain the reasons for weighing different technologies when the cost of the supplied power is the primary consideration.

A-12. Please see page 15 of the 2011 Resource Assessment. The goal of the Phase I Screening process was to select the top candidates across multiple technologies for further evaluation. For several technologies, multiple responses were considered in the Phase II analyses (see Table 11 and discussion on page 16 of the 2011 Resource Assessment). The Phase II analyses evaluated each option's impact on a variety of factors. These impacts are a function of the Companies' energy requirements and each option's cost and operating characteristics. Besides price, each technology has unique operating characteristics such as dispatchability, must take, and seasonal and hourly delivery profiles (e.g., wind, solar) that will impact the final cost to customers. Since it is not practical to consider all responses in the more detailed Phase II analyses, the Phase I Screening process was developed to ensure that the top options for each technology were considered in these analyses.

By selecting the most economic option(s) within each technology category, the Companies were able to quickly identify resource types that were likely to be part of a least-cost portfolio. For example, if the lowest priced wind proposal was not part of a least-cost portfolio then it would not make sense for higher priced wind proposals to be part of a least-cost portfolio. Because combined cycle gas technology was selected as potentially part of a least-cost portfolio, the Companies evaluated multiple combined cycle proposals.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 13

Witness: John N. Voyles, Jr.

Q-13. Refer to the Sinclair Testimony on page 17, which states, "[e]ach configuration had a different amount of duct-firing capacity. The 605 MW unit has 45 MW of duct-firing capacity." Explain what is meant by "duct-firing capacity."

A-13. In a combined cycle plant, power is generated by both combustion turbine generators ("CTG") and steam turbine generators ("STG"). For each of the configurations described on page 17 of the Sinclair Testimony, the combustion turbine capacity is the same. The energy (heat) in the CTG exhaust is utilized to produce steam in the heat recovery steam generator ("HRSG"). That steam is then converted to power using the STG.

When duct-firing capabilities are added to the design, additional heat can be provided by burning natural gas in the duct at the front end of the HRSG to increase the temperature of the exhaust stream entering the HRSG. The HRSG then converts the increased CTG exhaust energy to additional STG power. Duct-firing capacity consists of adding a larger burner and consequently a larger HRSG capable of producing more steam and a larger STG.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 14

Witness: David S. Sinclair

Q-14. Refer to page 17 of the Sinclair Testimony. Provide a brief explanation of why a coal unit was not considered in LG&E's and KU's 2011 IRP analysis.

A-14. A coal unit was considered in the Companies' 2011 IRP analysis. A coal unit was not considered in the expansion planning analyses associated with the 2011 Resource Assessment because a coal unit was not selected as part of the least-cost resource plan in the 2011 IRP.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 15

Witness: John N. Voyles, Jr.

Q-15. Refer to pages 18-19 of the Sinclair Testimony. Explain why the Penile Road location was selected as the interconnection point with Texas Gas Transmission.

A-15. LG&E and KU used Energy Management and Services Company to evaluate potential pipeline routes and rank the routes based on established factors to determine the most favorable route to provide natural gas to the Cane Run facility. On a macro level, five (5) potential interstate natural gas transmission systems were reviewed as potential suppliers to the Cane Run facility. The Texas Gas system is approximately 8 miles from the Cane Run site. Texas Eastern Transmission is the next closest gas transmission system to the Cane Run site at approximately 43 miles. Therefore, Texas Gas was selected for further study based upon its relative proximity.

Based on a study of available geographical information system ("GIS") data and field investigations, five (5) basic routes with three (3) different Texas Gas interconnection points were identified. Each route was scored in three basic areas: environmental impacts, cultural and socioeconomic factors, and engineering factors. The route beginning at Penile Road resulted in the best overall score.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 16

Witness: David S. Sinclair

Q-16. On page 19 of the Sinclair Testimony, there is discussion concerning the positives of purchasing the Bluegrass CTs. What are the estimated remaining service lives of the three generating units?

A-16. In the 2011 Resource Assessment, the Bluegrass CTs were assumed to operate through the end of the study period (2040). For the calculation of revenue requirements, a 20-year remaining book life was assumed. The units are currently approximately ten years old. Ultimately, the actual life of a unit is based on the way the unit is operated and maintained.

LOUISVILLE GAS AND ELECTRIC COMPANY
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KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 17

Witness: David S. Sinclair / Dan Arbough

Q-17. Refer to the 2011 Resource Assessment, Section 5 at page 17-18, and Appendix B-Key Assumptions.

a. Provide, in chart form, the cost item data used in the PROSYM model listed on page 17.

b. If not provided above, provide the gas price forecasts and the source used in the analysis.

c. Provide a discussion of the sensitivity of the results to a lower return on equity. Assuming a return on equity was 10 percent, explain whether any of the rankings of the various options, including the self-build option, would change.

d. The Percentage of Debt in Capital Structure is listed at 46.52 percent. If LG&E and KU are going to issue debt to finance any build options, explain the source of new equity that must also be provided in order to keep the capital structure unchanged.

A-17.

a. Please see the attachment. This information is being provided pursuant to the Companies' Petition for Confidential Protection filed contemporaneously herewith.

b. The natural gas price forecast used in this analysis was developed by the PIRA Energy Group. In the 2011 Resource Assessment, the Companies inadvertently copied the wrong natural gas prices into Table 20 on page 26. An updated table is included in the new confidential version of the document, which is being included as attachment to this response. This table contains the gas price forecast used in the analysis. This information is being provided pursuant to the Companies' Petition for Confidential Protection filed contemporaneously herewith.

c. The Companies must be granted the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments if they are to maintain their financial flexibility and ability to attract capital, but the rankings for the various options would not likely change with a slightly lower or higher return on equity.

d. There will be two sources of equity utilized to maintain the existing capital structure of the Companies. First, LG&E and KU will retain a portion of their earnings each quarter to fund a portion of the costs. Second, the parent company of the Companies, LG&E and KU Energy LLC, will provide equity contributions as needed to maintain a capital structure in line with the targeted capital structure.

2011 Resource Assessment

LG&E KU

PPL companies

Generation Planning & Analysis
September 2011

Table of Contents

List of Terms

Baghouse	Fabric filter baghouse
CATR	Clean Air Transport Rule
CCCT	Combined cycle combustion turbine
CCN	Certificates of Convenience and Necessity
CER	Capital Expenditure and Recovery
CERA	IHS CERA
CR7	Cane Run 7
CSAPR	Cross-State Air Pollution Rule
Companies	LG&E and KU
EPA	U.S. Environmental Protection Agency
NAAQS	National Ambient Air Quality Standards
O&M	Operating and maintenance
PIRA	PIRA Energy Group
PM	Particulate matter
PVRR	Present value of revenue requirements
RFP	Request for proposals
SAM	Sulfuric acid mist
SCCT	Simple-cycle combustion turbine
TC2	Trimble County 2
WFGD	Wet Flue Gas Desulfurization
2011 Compliance Plan	2011 Air Compliance Plan
2011 IRP	2011 Integrated Resource Plan
2012 Forecast	2012 load forecast

1 Executive Summary

The EPA is in the process of implementing an unprecedented number of air regulations over the next several years. These regulations will require the Companies to make significant investments in pollution control equipment, retire a number of its coal units, and invest in new generation capacity in order to reliably meet its customers' energy needs in the coming decades.

In March 2011, the EPA issued a proposed rule aimed at reducing hazardous air pollutants (such as mercury, other metals, acid gases, and organic air toxics, including dioxins) from new and existing coal- and oil-fired electric utility steam generating units ("HAPs Rule"). In August 2011, the EPA issued its final CSAPR that provides limited allowances for NO_x and SO_2 emissions starting in 2012. In addition, the EPA's NAAQS will further restrict NO_x and SO_2 emissions beginning in 2016 and 2017.

To comply with these regulations, the Companies must at all coal units (except Trimble County 2) either install additional emission controls or retire and replace the capacity. The Companies evaluated these decisions at each of its coal units and submitted its least-cost 2011 Compliance Plan to the Kentucky Public Service Commission in June 2011.[1] The least-cost compliance plan includes installing additional environmental controls on the Brown, Ghent, Mill Creek, and Trimble County 1 coal units. However, new controls were not least-cost for the Cane Run, Green River, and Tyrone coal units. The least-cost alternative for the six units at these plants is to retire and replace the capacity and energy.

In the 2011 Compliance Plan, the analyses of controls for the Cane Run and Green River coal units were based on preliminary cost estimates from Black & Veatch.[2] For the purposes of the analysis, since Tyrone 3 and Green River 3 are similar in size and vintage, the cost of controls for Tyrone 3 and Green River 3 was assumed to be equal. Given the operating characteristics, age, and size of the units as well as the controls needed to comply with pending environmental regulations, the cost of controls at Green River and Tyrone could not be justified. Since a significant reduction in the cost of controls for Cane Run could impact the Companies' ultimate decision regarding the Cane Run units, the Companies developed a revised estimate for the cost of controls at Cane Run based on the recently constructed common WFGD system which serves three coal-fired units at Brown and the more detailed 2011 Black & Veatch studies for Ghent, Mill Creek, and Brown. Based on these updated estimates, the Companies' analysis continues to show that retiring the Cane Run coal units and replacing them with new gas-fired capacity is the least-cost way to reliably meet its customers' future energy needs.

In April 2011, the Companies filed the 2011 IRP with the Kentucky Public Service Commission.[3] The 2011 IRP provides a detailed summary of the Companies' plan to meet future energy requirements at the lowest possible cost consistent with reliable supply. Like the 2011 Compliance Plan, the 2011 IRP found that the Cane Run, Green River, and Tyrone coal units should be retired at the end of 2015. The Companies' capacity needs through 2018, as identified in the 2011 IRP, are summarized in Table 1. With the retirements of the Cane Run, Green River, and Tyrone coal units, the Companies have a capacity shortfall in 2016 of 877 MWs.

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[1] See Case Nos. 2011-00161 and 2011-00162.

[2] For the units for which controls are recommended, the cost estimates for controls were based on more refined engineering estimates from Black & Veatch included in the Compliance Plan.

[3] See Case No. 2011-00140.

Table 1 – LG&E/KU Resource Summary (MW)

	2012	2013	2014	2015	2016	2017	2018
Forecasted Peak Load	7,210	7,356	7,477	7,603	7,654	7,760	7,897
Peak Reductions[4]	390	442	501	544	585	626	664
Total Demand	6,821	6,915	6,976	7,059	7,070	7,135	7,234
Existing Resources	8,002	8,006	8,001	7,996	7,969	7,970	7,970
Retirements					(797)	(797)	(797)
Firm Purchases (OVEC)	154	152	152	152	152	152	152
Total Supply	8,156	8,158	8,153	8,148	7,324	7,325	7,325
16% Reserve Requirements	1,091	1,106	1,116	1,129	1,131	1,142	1,157
Difference from Target	243	137	61	(40)	(877)	(952)	(1066)
Reserve Margin	19.6%	18.0%	16.9%	15.4%	3.6%	2.7%	1.3%

The least-cost expansion plan developed as part of the 2011 IRP selected a 907 MW 3X1 CCCT to meet future capacity and energy needs beginning in 2016. The IRP is a complete resource assessment and acquisition plan that considers all of the Companies' supply-side technologies and demand-side resource alternatives, but it does not consider resources that could be supplied by the marketplace. For this reason, the Companies issued an RFP in December 2010 for electric energy and capacity. Responses to the RFP included power purchase agreements and asset sale offers from gas, coal, nuclear, wind, biomass, and solar technologies.

The Companies' analysis of the RFP responses was completed in two phases. The Phase I Screening consisted of an initial screening of the responses through the use of a scoring system which evaluated attributes including cost, term, and site viability. The goal of the Phase I Screening process was to select the top candidates from each technology for further evaluation. Phase II of the analysis evaluated the top candidates (and various combinations of the top candidates) from the Phase I Screening in more detail. Phase II was completed in two parts and also included an analysis of the Companies' self-build alternatives developed independently from the analytical team evaluating the RFP responses.

Based on the RFP and self-build analysis, the least-cost alternative for meeting the future capacity and energy needs of the Companies is to build a 640 MW 2X1 CCCT at the Cane Run site ("Cane Run 7" or "CR7") and purchase the existing Bluegrass SCCT facility in La Grange, Kentucky from LS Power. To effectuate this plan, the Companies will need to make appropriate regulatory filings for these generating resources and any related transmission facilities. The resources are needed to replace capacity that will be retired prior to the end of 2015 as a result of the EPA regulations and to meet the anticipated load growth in the Companies' service territories. Specifically, the resources include:

i. the construction of the Cane Run 640 MW 2X1 natural gas CCCT project (to be permitted as CR7) and any related electric and gas transmission facilities needed to deliver CR7 energy to load prior to January 1, 2016.

[4] Peak reductions include the impacts of interruptible loads and demand-side management programs.

ii. the purchase from LS Power of the existing SCCTs at its Bluegrass facility in La Grange, Kentucky and any related transmission facilities needed to deliver the associated energy to load. The Bluegrass CTs would be available during 2012.

The timeline for constructing the CR7 unit is constrained by the need to have the unit operational prior to January 1, 2016, when the retirement of approximately 800 MW of coal-fired capacity at Cane Run, Tyrone, and Green River is planned due to impending EPA regulations. The January 2016 retirements assume a one year extension is granted for these units to meet the HAPs standards.

The purchase of the existing Bluegrass facility from LS Power is needed to meet the same January 1, 2016 need. The existing facilities at Bluegrass are already in operation. An agreement with LS Power will enable purchase in 2012. These assets will be available during the construction of the CR7 project to mitigate development risks as well as operational risks associated with the retiring coal units as their maintenance expenses are minimized ahead of retirement in the interest of prudently managing costs.

2 Summary of Environmental Regulations

The EPA's NAAQS, CSAPR, and HAPs Rule are precipitating the need for additional emissions reductions over the next several years. Each of these regulations is discussed in more detail in the following sections.

2.1 National Ambient Air Quality Standard

The EPA's NAAQS places further restrictions on SO_2 and NO_x emissions beginning in 2016 and 2017. The SO_2 and NO_2 NAAQS are final. Compliance with NAAQS emission limits are established on a site-by-site basis by the permitting authority. Table 2 summarizes the Companies' current (2010) SO_2 and NO_x emissions at the Cane Run, Green River, and Tyrone units, as well as the expected NAAQS emission limits for meeting the revised NAAQS emission requirements at those stations.

Table 2 – NAAQS SO_2 Emission Limits

	SO_2 Rate (lb/mmBtu)		**NO_x Rate (lb/mmBtu)**	
Unit	**Current Emissions (2010)**	**Expected NAAQS Limits**	**Current Emissions (2010)**	**Expected NAAQS Limits**
Cane Run	0.55	0.06	0.34	0.07
Green River	4.08	0.15	0.40	0.56
Tyrone[5]	1.33	0.15	0.48	0.56

To comply with the expected NO_2 NAAQS, new NO_x emission controls would need to be installed at the Cane Run station prior to 2016.[6] New SO_2 emission controls would need to be installed at the Cane Run, Green River, and Tyrone stations prior to 2017.[7] The Cane Run units have first generation FGDs built in the 1970s. In addition, the Cane Run units are not equipped with SCRs. Cane Run would require extensive improvements to the existing FGDs and the installation of new SCRs to control NO_x to comply with expected emission limits from the revised NAAQS regulations.

2.2 Cross-State Air Pollution Rule

In July 2010, the EPA issued a proposed CATR which provides limited allowances for NO_x and SO_2 emissions starting in January 2012. The final version of this rule, called the CSAPR, was issued in August 2011. Compliance with the CSAPR is measured on a system-wide basis. Table 3 summarizes the CATR and CSAPR allowance allocations as well as the Companies' current (2010) SO_2 and NO_x emissions.

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[5] A detailed NAAQS analysis was not performed for the Tyrone station. For the purposes of this analysis, the expected NAAQS limits for Tyrone and Green River were assumed to be equal.

[6] As of this time, Jefferson, Anderson and Muhlenburg Counties have been declared as "unclassified" by the State of Kentucky for the revised NO_2 NAAQS. The EPA could require the state to perform modeling to verify compliance and classification. It is expected that modeling could demonstrate that Jefferson County could be non-attainment for the revised NO_2 NAAQS. Additionally, Jefferson County has measured several exceedances of the existing ozone NAAQS during 2010 and 2011. Should there be further exceedances measured in 2012, Jefferson County could become non-attainment for the existing ozone NAAQS, triggering actions to be implemented for ozone attainment (historically, further NO_X reductions from stationary sources have been implemented).

[7] As of July 2011, Kentucky declared Jefferson County "non-attainment" for SO_2 triggering agency actions to remedy the violations. While Anderson and Muhlenberg counties, where the Tyrone and Green River stations, respectively, are located, were declared "unclassified" (there are no monitors in these counties), the EPA may require the State to perform "modeling" to verify compliance and the classification.

Table 3 – CATR and CSAPR Emission Allowances

	Current Emissions	CATR Allowances		CSAPR Allowances	
	2010	2012	2014	2012	2014
SO_2 Emissions (Tons)	92,241	66,866	43,215	78,697	36,339
NO_x Emissions (Tons)	31,826	23,718	23,718	29,500	26,831

Note: Values shown reflect Companies' share (75%) of Trimble County allowances.

CSAPR made significant changes in emission allowance allocations compared to the former CATR allocations. CSAPR NO_x allowance allocations are higher than the proposed CATR allocations but still below the Companies 2010 emissions. CSAPR SO_2 allowance allocations are higher than CATR in 2012 and 2013 but lower in 2014 and beyond. To comply with the CSAPR, the Companies' SO_2 emissions will have to decrease by more than 60% by 2014 and NO_x emissions will have to decrease by approximately 15%.

2.3 HAPs Rule

In March 2011, the EPA issued a proposed HAPs Rule aimed at reducing hazardous air pollutants (such as mercury, other metals, acid gases, and organic air toxics, including dioxins) from new and existing coal- and oil-fired electric utility steam generating units. Under a consent decree between the EPA and various states and environmental groups, the rule is to be issued as a final rule in November 2011 with compliance required around January 2016, assuming a 1-year compliance extension is granted by the permitting authority. The HAPs Rule limits mercury and PM (the surrogate for non-mercury metals), the latter including SAM (as a condensable particulate). The current mercury and particulate matter emissions for the Cane Run, Green River, and Tyrone coal units are summarized in Table 4 along with the proposed emission limits from the HAPs rule.

Table 4 – Current HAPs Emissions

Unit	Summer Capacity (MW)	Mercury Emissions (lb/TBtu)	PM_{Total} Emissions (lb/mmBtu)
Cane Run 4	155	3.6	0.05
Cane Run 5	168	2.9	0.06
Cane Run 6	240	3.8	0.06
Green River 3	68	6.3	0.13*
Green River 4	95	5.4	0.12*
Tyrone 3	71	6.3[8]	0.16*
HAPs Rule Limits		**1.2**	**0.03**

*Condensable PM for the Green River and Tyrone units is based on estimated SO_3 concentration.

Based on the Black & Veatch engineering studies for the 2011 Compliance Plan, a baghouse is the most effective control technology for HAPs emissions. A baghouse is expected to reduce mercury emissions to 0.6 pounds per TBtu and particulate matter emissions to 0.0258 pounds per mmBtu. A baghouse will

[8] For the purposes of this analysis, since Tyrone 3 and Green River 3 are similar in size and vintage, mercury emissions for Tyrone 3 was assumed to equal that of Green River 3.

be required on each of the Cane Run, Green River, and Tyrone units to continue operation of these units under the HAPs rule.

3 Cane Run Cost of Controls

In the 2011 Compliance Plan, new environmental controls were not recommended for the Cane Run, Green River, and Tyrone coal units. Table 5 contains the results of the Compliance Plan analysis for these units as well as the total capital cost of controls needed to comply with EPA regulations[9].

Table 5 – NPVRR Differences and Capital Costs for Controls

	NPVRR ($Millions)			Capital ($Millions)
Unit(s)	**Install Controls (A)**	**Retire/Replace Capacity (B)**	**Difference (B)-(A)**	**Total Capital Cost of Controls – 2011 Compliance Plan**
Tyrone 3	33,125	33,124	(1)	45
Green River 3	33,124	33,055	(69)	45
Green River 4	32,917	32,823	(94)	66
Cane Run 4	33,055	32,967	(88)	295
Cane Run 5	32,975	32,917	(58)	399
Cane Run 6	32,967	32,975	8	310

The analyses of controls for Cane Run and Green River were based on an initial round of cost estimates from Black & Veatch.[10] For the purposes of this analysis, since Tyrone 3 and Green River 3 are similar in size and vintage, the cost of controls for Tyrone 3 and Green River 3 was assumed to be equal.[11] Given the operating characteristics, age, and size of the units as well as the controls needed to comply with current environmental regulations, the cost of controls at Green River and Tyrone cannot be justified.

Since a significant reduction in the cost of controls for Cane Run could impact the Companies' ultimate decision regarding Cane Run, the Companies developed a revised estimate for the cost of controls at Cane Run based on the recently constructed common WFGD system which serves three coal-fired units at Brown and the more detailed 2011 Black & Veatch studies for Ghent, Mill Creek, and Brown. The revised estimate for controls at Cane Run included a common WFGD system and common limestone processing facilities. In addition, the costs of baghouses were escalated by 37%.[12] The original and revised estimates for the cost of controls at Cane Run are summarized in Table 6.

[9] Updated results for the Green River and Tyrone coal units were provided in Case No. 2011-00161 in response to the supplemental requests for information of Rick Clewett, Raymond Barry, Sierra Club and the Natural Resource Defense Council dated August 18, 2011, Question No. 8.

[10] For the units for which controls are recommended, the cost estimates for controls were based on additional engineering estimates from Black & Veatch included in the 2011 Compliance Plan.

[11] The Compliance Plan did not contemplate the cost of transmission upgrades associated with retiring units. Initial rough estimates for these costs were $35 million for Green River, $42 million for Cane Run, and $0 for Tyrone. The Companies' recommendation to retire these units is not impacted by these costs.

[12] Compared to the initial round of cost estimates, the costs of baghouses in the more detailed estimates from Black & Veatch (in the Compliance filing for Ghent, Mill Creek, and Brown) were 37% higher on average.

Table 6 – Total Capital Cost of Cane Run Controls ($M)

Unit	Original Estimate: 2011 Compliance Plan	Revised Estimate[13]
Cane Run 4	295	133
Cane Run 5	310	144
Cane Run 6	399	180
Common	N/A	532
Total	1,004	990

Compared to the original estimate, the cost of controls in the revised estimate is $14 million lower. This reduction in capital cost equates to approximately $14 million reduction in PVRR. With the original cost estimates, the total PVRR for all of the Cane Run units is $138 million (in favor of retirement -- see Table 5). Clearly, the PVRR reduction associated with the lower capital cost does not offset this total.[14]

[13] Values do not sum precisely to the total due to rounding.

[14] The common WFGD and limestone processing facilities in the revised estimate preclude the retirement of individual units at Cane Run.

4 Future Resource Needs

In June 2011, the Companies submitted the 2011 Compliance Plan, its least-cost plan for complying with proposed and existing environmental regulations, to the Kentucky Public Service Commission.[15] The 2011 Compliance Plan demonstrated the need for environmental controls and then – for the units for which controls are needed – compared the difference in PVRR between (a) installing controls and (b) retiring and replacing capacity. New controls were not recommended for the Cane Run, Green River, and Tyrone coal units because the PVRR analysis demonstrated that retiring and replacing the capacity and energy from these units was least-cost.

In April 2011, the Companies filed the 2011 IRP with the Kentucky Public Service Commission.[16] The 2011 IRP provides a detailed analysis of the Companies' plan to meet future energy requirements at the lowest possible cost consistent with reliable supply. Like the 2011 Compliance Plan, the 2011 IRP found that the Cane Run, Green River, and Tyrone coal units should be retired not later than the end of 2015 to comply with the EPA regulations in a least-cost manner. The Companies' capacity needs through 2016, as identified in the 2011 IRP, are summarized in Table 7. With the retirements of the Cane Run, Green River, and Tyrone coal units, the Companies have a capacity shortfall in 2016 of 877 MWs. The retirements will result in a 2016 reserve margin of approximately 4% versus a target reserve margin of 16%.

Table 7 – LG&E/KU Resource Summary – 2011 IRP/ECR Filing (MW)

	2012	2013	2014	2015	2016	2017	2018
Forecasted Peak Load	7,210	7,356	7,477	7,603	7,654	7,760	7,897
Peak Reductions[17]	390	442	501	544	585	626	664
Total Demand	6,821	6,915	6,976	7,059	7,070	7,135	7,234
Existing Resources	8,002	8,006	8,001	7,996	7,969	7,970	7,970
Retirements					(797)	(797)	(797)
Firm Purchases (OVEC)	154	152	152	152	152	152	152
Total Supply	8,156	8,158	8,153	8,148	7,324	7,325	7,325
16% Reserve Requirements	1,091	1,106	1,116	1,129	1,131	1,142	1,157
Difference from Target	243	137	61	(40)	(877)	(952)	(1066)
Reserve Margin	19.6%	18.0%	16.9%	15.4%	3.6%	2.7%	1.3%

In June 2011, the Companies developed a new load forecast as part of its annual planning process ("2012 Forecast"), which is still in progress. Even though the 2016 need for capacity is primarily driven by the need to retire existing coal capacity (and not load growth), the Companies evaluated the 2016 capacity need based on the new load forecast. Table 8 compares the new load forecast to the load forecast used in the 2011 IRP and ECR filings. Overall, the Companies' need for capacity beginning in 2016 is unchanged. In the 2011 IRP, expansion plans for the high and low load scenarios both included

[15] See Case Nos. 2011-00161 and 2011-00162.
[16] See Case No. 2011-00140.
[17] Peak reductions include the impacts of interruptible loads and demand-side management programs.

CCCT capacity in 2016. This demonstrates that the sensitivity of the 2016 need for capacity to load growth is fairly low.

Table 8 – Summer Peak Demand Forecasts – After Reductions for DSM and Curtailable Load

	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
2011 IRP/ECR/RFP	6,821	6,915	6,976	7,059	7,070	7,135	7,234
2012 Forecast	6,930	6,968	7,004	7,039	7,121	7,164	7,223
Difference	109	53	28	(20)	51	29	(11)

The retirement of the Cane Run and Green River coal units also have an impact on the Companies' energy needs. Table 9 summarizes the energy produced from these stations over the last five years.

Table 9 – Cane Run and Green River Energy Production

Generation (GWh)	**2006**	**2007**	**2008**	**2009**	**2010**
Cane Run	3,575	3,537	3,401	3,235	3,263
Green River	640	997	962	625	889
Total	4,215	4,533	4,364	3,861	4,153
Capacity Factor	**2006**	**2007**	**2008**	**2009**	**2010**
Cane Run	72%	72%	69%	66%	66%
Green River	45%	70%	63%	41%	60%

5 Analysis of Responses to Request for Proposal

The least-cost expansion plan developed as part of the 2011 IRP selected a 3X1 907 MW CCCT to meet the Companies' capacity shortfall beginning in 2016. The IRP is a complete resource assessment and acquisition plan that considers all of the Companies' supply-side and demand-side resource alternatives, but it does not consider alternatives that may be available from others. For this reason, the Companies issued an RFP in December 2010 for electric energy and capacity. Responses to the RFP included power purchase agreements and asset sale offers for gas, coal, nuclear, wind, biomass, and solar technologies.

The Companies' analysis of the RFP responses was completed in two phases. The Phase I Screening consisted of an initial screening of the responses through the use of a scoring system which evaluates attributes including cost, term, and site viability. The goal of the Phase I Screening process was to select the top candidates from each technology for further evaluation. Phase II of the analysis evaluated the top candidates (and various combinations of the top candidates) from the Phase I Screening in more detail. Phase II was completed in two parts and included the Companies' self-build alternatives.

5.1 Request for Proposals

On December 1, 2010, the Companies issued an RFP for capacity and energy to more than 116 potential energy suppliers. A copy of the RFP and its recipients is included as an attachment to this report. The Companies requested proposals from parties with resources that would qualify as a Designated Network Resource for transmission purposes. The RFP did not limit responses to a particular set of fuels or generating technologies. The specified capacity range for the responses was broad: the RFP encouraged offers for firm summer and winter capacity ranging between 1 MW and 700 MW with the caveat that the Companies may procure more or less than 700 MW and may aggregate capacity and energy from multiple parties to meet its needs. The RFP cited the Companies' preference for longer-term proposals but did not exclude shorter-term proposals.

In total, 18 parties responded to the RFP with 50 offers. Table 10 summarizes the responses to the RFP. Copies of the responses to the RFP are included as an attachment to this report.

Table 10 – RFP Responses

Response Number	Technology/ Offer Type	Respondent	Location
1A	[redacted]		
1B			
2A			
2B			
3			
4			
5A			
5B			
6A			
6B			
6C			
6D			
6E			

Response Number	Technology/ Offer Type	Respondent	Location
6F	[redacted]	[redacted]	[redacted]
7A	[redacted]	[redacted]	[redacted]
7B	[redacted]	[redacted]	[redacted]
7C	[redacted]	[redacted]	[redacted]
7D	[redacted]	[redacted]	[redacted]
8A	[redacted]	[redacted]	[redacted]
8B	[redacted]	[redacted]	[redacted]
8C	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]
13A	[redacted]	[redacted]	[redacted]
13B	[redacted]	[redacted]	[redacted]
13C	[redacted]	[redacted]	[redacted]
13D	[redacted]	[redacted]	[redacted]
13E	[redacted]	[redacted]	[redacted]
13F	[redacted]	[redacted]	[redacted]
13G	[redacted]	[redacted]	[redacted]
13H	[redacted]	[redacted]	[redacted]
13I	[redacted]	[redacted]	[redacted]
13J	[redacted]	[redacted]	[redacted]
14A	[redacted]	[redacted]	[redacted]
14B	[redacted]	[redacted]	[redacted]
15	[redacted]	[redacted]	[redacted]
16A	[redacted]	[redacted]	[redacted]
16B	[redacted]	[redacted]	[redacted]
16C	[redacted]	[redacted]	[redacted]
17	[redacted]	[redacted]	[redacted]
18	[redacted]	[redacted]	[redacted]
19A	[redacted]	[redacted]	[redacted]
19B	[redacted]	[redacted]	[redacted]
20A	[redacted]	[redacted]	[redacted]
20B	[redacted]	[redacted]	[redacted]
21A	[redacted]	[redacted]	[redacted]
21B	[redacted]	[redacted]	[redacted]
22	[redacted]	[redacted]	[redacted]

5.2 Phase I Screening Analysis

In the Phase I screening analysis, RFP responses were grouped by source technology. The groupings were:

- Natural Gas CCCT

- SCCT
- Nuclear
- Coal
- Wind
- Solar
- Landfill Gas
- Biomass

The responses were screened using a scoring system which evaluated attributes including cost, term, and site viability. One offer from [redacted] for [redacted] was overly vague and not considered in the Phase 1 Screening analysis. The goal of the Phase I Screening process was to select the top candidates across multiple technologies for further evaluation. While some technologies may score poorly on specific measures, the top candidate(s) from each technology were still retained for further analysis, since selecting combinations of proposals across technologies was possible.

The scoring system was developed as follows. First, responses with unacceptable terms or sites were eliminated. Two responses were eliminated because the term did not extend beyond 2015; no responses were eliminated because the site was considered unacceptable. Second, the responses were ranked based on two cost measures: (a) levelized revenue requirements per MWh and (b) levelized revenue requirements per firm capacity-year. 15% of wind capacity and 40% of solar capacity was assumed to be firm capacity under summer peak conditions. The responses considered for further review were the responses that ranked most favorably in both cost categories. The responses selected in the Phase I Screening analysis are summarized in Table 11. A complete summary of the Phase I Screening results are contained in Appendix A – Phase I Screening Results.

Table 11 – Phase I Screening Results

Response Number	Technology	Respondent	Rank
13I	[redacted]		1
13H			2
13J			3
13G			4
4			5
12			6
9			7
13E			1
13D			2
13F			3
13B			4
13A			5
13C			6
5A			1
5B			2
14B			3
22			1
16A			1
16B			2
21A			1
21B			2
6A			1
14A			2
10			3

For each technology, the cutoff point for the number of responses considered for further evaluation was determined based on the levelized cost measures. For example, if the top five responses for a given technology were separated by a relatively large gap in the levelized cost measures, only five responses were considered for further evaluation. If no such gap existed, all responses for a given technology were considered for further evaluation. Because so many offers for CCCT capacity and energy were received, the offers were evaluated across multiple load factors to ensure that the same offers consistently ranked highest.

5.3 Phase II Analysis

The Phase II analysis evaluated the top responses from the Phase I Screening analysis in more detail. Strategist resource planning software was used to assess each option's impact on future capacity needs and the PROSYM production costing model was used to evaluate the production cost revenue requirements associated with each option. The CER module of Strategist calculated revenue requirements associated with capital expenditures for RFP resources (where applicable – for asset sales and transmission capital) as well as future capacity needs. These capital revenue requirements were combined with the production cost revenue requirements from PROSYM as well as revenue requirements for any fixed O&M, gas transportation costs, and firm electric transmission costs to produce a total system revenue requirement for the study period.

PROSYM is a chronological production costing model that is designed for performing planning and operational studies on an hourly basis. PROSYM simulates the Power Supply System Agreement's joint dispatch provisions and is able to simulate the utilization of the generation resources and purchased power alternatives considered in this analysis. Together, Strategist and PROSYM have formed the foundation of prior analyses involving certificates of public convenience and necessity for new generating plants, environmental cost recovery for pollution control equipment, and the fuel adjustment clause.

In the Phase II analysis, the evaluation of each option considered the following cost items:

- Capital and fixed O&M costs for RFP resources.
- Capital and fixed O&M costs for future capacity needs.
- Capital costs for necessary electric transmission upgrades.
- Where applicable, gas transportation costs and the cost of firm electric transmission capacity.
- Production costs (fuel, variable O&M including consumables, and emissions) for existing, RFP, and future resources.

The Phase II analysis was completed in two parts: 'preliminary' Phase II analysis and 'final' Phase II analysis. After the preliminary Phase II analysis, the Companies met with the leading respondents and asked them to update their proposals to their "best and final" offer. In the final Phase II analysis, the updated proposals were evaluated along with additional self-build alternatives developed independently from the analytical team performing the Phase II analysis. The following sections summarize the preliminary and final Phase II analyses. Key assumptions for the Phase II analysis are summarized in Appendix B – Key Assumptions.

5.3.1 Preliminary Phase II Analysis

The preliminary Phase II analysis evaluated each option from the Phase I Screening analysis in more detail. Based on the 2011 IRP, the Companies' need for capacity in 2016 is 877 MW (see Table 7). Because capacity additions of less than 600 MW do not defer the need for a 907 MW 3X1 CCCT in 2016, the Companies considered various RFP responses in combination.

Table 12 summarizes the options considered in the preliminary Phase II analysis. LS Power provided the option of purchasing or entering into a PPA for one, two, or three of its Bluegrass SCCTs. The Bluegrass SCCTs were considered in combination with other alternatives to defer the need for capacity beyond 2016. Because of concerns regarding the ability to purchase and the complexities of operating only a portion of the Bluegrass station, the Companies did not consider purchasing fewer than all three of the Bluegrass SCCTs. Furthermore, because one SCCT (in combination with other alternatives) does not defer the need for additional capacity beyond 2016, the Companies did not consider a PPA for one Bluegrass SCCT.

[redacted] submitted two offers for [redacted] from [redacted]. Because the offers were similarly priced, the Companies considered the option with the longer term (10 years) in the preliminary Phase II analysis. The landfill gas and biomass alternatives have similar operating characteristics, but the costs of the biomass alternatives were lower. As a result, only the biomass alternatives were considered in the preliminary Phase II analysis. Finally, since the top wind alternatives are similarly priced and only a small portion of wind capacity can be considered firm under peak conditions, only the wind alternative with the largest capacity was considered in the preliminary Phase II analysis.

Table 12 – Options Considered in Preliminary Phase II Analysis

Response Number(s)	Respondent	Description
13H	[redacted]	[redacted]
13I	[redacted]	[redacted]
13J	[redacted]	[redacted]
4	[redacted]	[redacted]
4 13E	[redacted]	[redacted]
5B	[redacted]	[redacted]
5B 13F	[redacted]	[redacted]
5B 13C	[redacted]	[redacted]
5B 13F 16A	[redacted]	[redacted]
9	[redacted]	[redacted]
9 13E	[redacted]	[redacted]
	[redacted]	[redacted]
12	[redacted]	[redacted]
14B 13F	[redacted]	[redacted]
14B 5B	[redacted]	[redacted]
13E	[redacted]	[redacted]
13E 10	[redacted]	[redacted]
13C	[redacted]	[redacted]
5B 13F	[redacted]	[redacted]
22 13F	[redacted]	[redacted]

Strategist was used to develop a least-cost expansion plan for each alternative. In initial iterations of the preliminary Phase II analysis, future capacity additions through 2025 included only natural gas technologies (2X1 CCCT, 3X1 CCCT, and SCCT). Other technologies considered (but not selected) in the 2011 IRP – including supercritical coal, wind, landfill gas, and hydroelectric units – were never selected in the first fifteen years of the analysis period.

Once the expansion plans were developed for each option, the RFP resource(s) and future capacity additions were modeled in PROSYM along with the Companies' existing resources to compute production costs. The analysis considered each option's impact on the Companies' ability to serve native load only; off-system sales were not allowed. Each alternative was evaluated under two economy market purchase scenarios: (1) no economy purchases and (2) limited economy purchases. Furthermore, in addition to the base case scenario for natural gas and electricity prices, the alternatives were evaluated based on natural gas and electricity prices from CERA.

The results of the preliminary Phase II analysis are summarized in Appendix C – Preliminary Phase II Analysis Results. Production costs include fuel, variable O&M, start-up costs, and emissions costs for existing, RFP, and future resources. Capital costs include capital for RFP resources (where applicable, for asset sale offers) as well as capital for future capacity additions. Gas transportation costs include the cost of gas transportation for RFP resources and future capacity additions. Capacity costs include capacity payments for PPA alternatives. Electric transmission costs include capital for transmission upgrades and the cost of buying firm transmission capacity.[18]

The parties with the top responses from the preliminary Phase II analysis are summarized in Table 13. In the preliminary Phase II analysis, the [redacted] and [redacted] alternatives were considered in combination with the least-cost alternative to understand the incremental impact of these renewable options on the PVRR. In Appendix C, the [redacted] alternative has the third or fourth lowest PVRR, but the [redacted] alternative was not included in the short-list of RFP responses. The costs of all the wind alternatives are higher than the costs of the [redacted] biomass alternatives. Based on price and the fact that a fairly small portion of wind capacity can be considered firm under peak conditions, wind (in combination with another alternative) would not be lower-cost than biomass (in combination with another alternative).

Table 13 – Short-List of RFP Responses

Respondent	Technology	Capacity	Description
[redacted]			

5.3.2 Final Phase II Analysis

After the preliminary Phase II analysis, the Companies met with each of the top respondents (see Table 13) and asked them to update their responses to "best and final" offers. The updated responses are included as an attachment to this report. The updated responses were evaluated in the final Phase II analysis along with additional self-build options. The options considered in the final Phase II analysis are listed in Table 14. A more detailed summary of these options is included in Appendix D – Summary of Final Phase II Alternatives.

[18] Transmission upgrades are required if generation at Cane Run is not replaced in 2016. In the preliminary Phase II analysis, alternatives that did not defer the need for additional capacity beyond 2016 were not assessed this cost.

Table 14 – Options Considered in Final Phase II Analysis

Response Number	Respondent	Description
13C	[redacted]	
13F		
13C		
13C		
13E		
13E		
13E		
13C 5B		
4 13C		
12 13E		
13J		
12		
4 13E		

The [redacted] offer was not identified as a top response in the preliminary Phase II analysis. The location of the [redacted] assets, in [redacted], resulted in high electric transmission costs. However, it was retained in the final Phase II analysis because updated gas transportation costs for the [redacted] option were notably lower than what was assumed in the preliminary Phase II analysis.[19] Because combinations of the Bluegrass CTs and the Companies' self-build 2X1 CCCT option were among the top options in the preliminary Phase II analysis, the Companies independently developed estimates for two alternative self-build 2X1 CCCT configurations. Whereas the 605 MW unit has 45 MW of duct firing capacity, the 640 and 690 MW units have 80 and 130 MW of duct firing capacity, respectively.

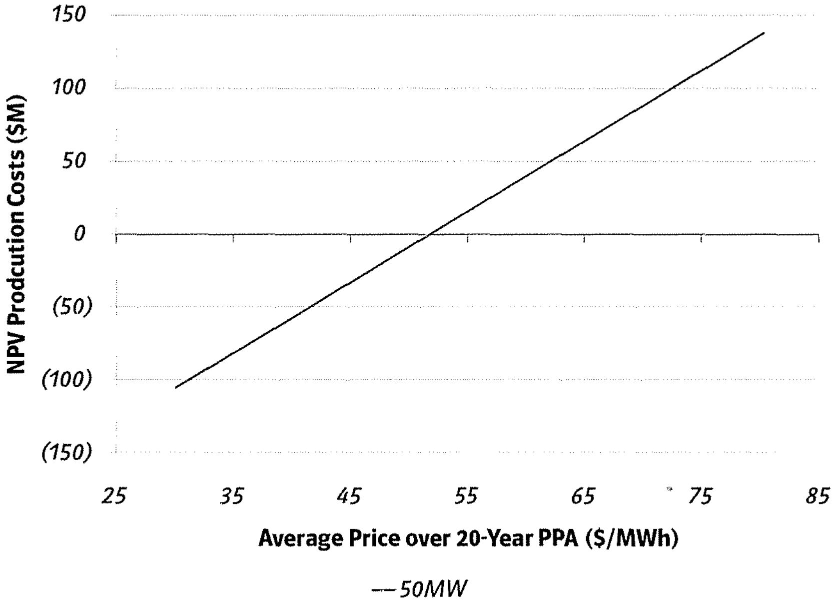
Like the preliminary Phase II analysis, the final Phase II analysis considered each option's impact on the Companies' ability to serve native load only; off-system sales were not allowed. Each alternative was evaluated under two economy market purchase scenarios: (1) no economy purchases and (2) limited

[19] Gas transportation costs and other assumptions were refined in each part of the analysis. Gas transportation costs for other options not considered in the final phase II analysis did not change significantly from what was assumed in the preliminary phase II analysis. Since this analysis was conducted, [redacted].

economy purchases. The alternatives were evaluated initially under the Companies' base case coal, natural gas, and electricity price scenario.

The [redacted] PPA was ultimately eliminated from the final Phase II analysis because it was not least-cost. Figure 1 plots the impact of a 50 MW round-the-clock purchase on production costs at varying purchase prices. The average price of the [redacted] option over the life of the PPA is $[redacted]/MWh. This option was eliminated from the final Phase II analysis because, based on Figure 1, round-the-clock power purchases with costs greater than $50-55/MWh negatively impact production costs.

Figure 1 – Impact of 50 MW Round-the-Clock Purchase on Production Costs



The capital cost assumptions utilized in the analysis of RFP responses for electric transmission are summarized in Table 15. If no generation is added at the Cane Run site, the nominal cost of transmission upgrades was assumed to be $41.9 million.[20] If the Cane Run coal units are replaced by a CCCT unit, the capital cost for transmission was assumed to be $9.4-$9.9 million, depending on the capacity of the CCCT unit. If the Companies enter into a PPA for two Bluegrass CTs, the cost of transmission was assumed to be $3.3 million; the cost of transmission associated with purchasing or entering into a PPA for three Bluegrass CTs was assumed to be $38.8 million. Since the [redacted] alternative does not include generation at the Cane Run site, the cost of transmission for this alternative (for example) was assumed to be $80.7 million ($41.9 million plus $38.8 million).

[20] Because the cost of transmission upgrades associated with retiring the Green River coal units is the same for all alternatives, this cost was not considered in the analysis of RFP responses.

Table 15 – Electric Transmission Capital Cost Assumptions[21]

Project	Cost (Nominal Dollars - Millions)
No Generation at Cane Run Site	41.9
605 MW CCCT at Cane Run Site	9.4
640 MW CCCT at Cane Run Site	9.7
690 MW CCCT at Cane Run Site	9.9
PPA for Two Bluegrass CTs	3.3
Purchase/PPA for Three Bluegrass CTs	38.8

Table 16 contains a high level summary of the final Phase II analysis results. A more detailed summary of the results are included in Appendix E – Final Phase II Analysis Results. The 'SB 2X1 (640) + 3 CTs (Sale – 2012)' alternative is the least-cost alternative for meeting the Companies' future capacity and energy needs. The purchase price from LS Power for the Bluegrass CTs is very attractive; the cost of the Bluegrass CTs (approximately \$220/kW) is less than 30% of the cost of a new SCCT (approximately \$850/kW per the 2011 IRP). Furthermore, compared to the 640 MW CCCT, the production cost savings associated with the 690 MW CCCT do not outweigh the additional capital and gas transportation costs associated with the larger unit. The capital costs for the least-cost alternative are summarized in Table 17.

Table 16 – Final Phase II Analysis Results (\$M)

No Economy Purchases		Limited Economy Purchases	
Alternative	**PVRR Difference from Best Option**	**Alternative**	**PVRR Difference from Best Option**
[redacted]			

Note: 'SB' stands for self-build; 'CTs' refer to Bluegrass CTs.

[21] These assumptions were based on preliminary rough order of magnitude estimates of transmission capital requirements.

Table 17 – Capital Costs for Least-Cost Alternative – Final Phase II Analysis

Item	**Cost (Nominal Dollars - Millions)**
640 MW CCCT	662
3 Bluegrass CTs (Sale – 2012)	120
Total Generation	**782**
Cane Run Transmission	10
Bluegrass Transmission	39
Total Transmission	**49**
Total Capital Cost	**829**

6 Updates to Capital Costs

The least-cost alternative for meeting the Companies' future capacity and energy needs was identified in May 2011. After this decision was made, the Companies entered into negotiations with LS Power for purchasing the Bluegrass CTs and began refining cost estimates for its self-build CCCT options and the transmission facilities needed to deliver energy from these generating resources to load. Table 18 compares the updated capital costs for the least-cost alternative to the capital costs utilized in the final Phase II analysis.

Table 18 – Updated Capital Costs for Least-Cost Alternative (Nominal Dollars – Millions)

Item	Final Phase II Analysis (May 2011)	Updated Capital Costs (August 2011)
640 MW CCCT	662	583
3 Bluegrass CTs (Sale – 2012)	120	110
Total Generation	**782**	**693**
Cane Run Transmission	10	34
Bluegrass Transmission	39	5
Total Transmission	**49**	**39**
Total Capital Cost	**829**	**732**

During negotiations with LS Power, the purchase price of the Bluegrass CTs was reduced by $10 million to $110 million. This price is contingent on the Companies' ability to close the transaction with LS Power by June 30, 2012. The cost estimates for the 640 MW CCCT (CR7) and the necessary transmission facilities also decreased. In total, the cost of the least-cost alternative decreased by $97 million.

To demonstrate the impact of these cost updates on the analysis of RFP responses, the Companies re-evaluated the final Phase II alternatives with updated capital costs for its self-build alternatives and transmission facilities. The 20-year PVRR associated with the updated costs of new transmission facilities is $34.2 million. Because the impacts to the transmission system of CR7 and the Bluegrass CTs were evaluated together, it is difficult to allocate transmission costs to each generation source. For the purposes of this analysis, $31.6 million of the total was allocated to CR7 and $2.6 million was allocated to the Bluegrass CTs. Given the nature of the transmission upgrades, the capital cost for transmission does not vary based on the capacity of replacement generation at the Cane Run site. In addition, the cost of transmission associated with the Bluegrass CTs is not impacted by the number of CTs transacted.

Table 19 contains the updated final Phase II results. A more detailed summary of the results are included in Appendix F – Updated Final Phase II Analysis Results. Overall, the reduced costs of the Bluegrass CTs and the self-build options widen the gap between alternatives that include these options and the best and final offers for alternatives that do not include these options.

Table 19 – Updated Final Phase II Analysis Results

No Economy Purchases		Limited Economy Purchases	
Alternative	PVRR Difference from Best Option	Alternative	PVRR Difference from Best Option
[redacted]			

7 Analysis of Key RFP Inputs

The analysis of RFP responses was based on multiple inputs having a range of potential values. The following sections assess the sensitivity of the analysis to changing commodity prices and load.

7.1 Commodity Prices

The analysis of RFP responses are based on forecasts of coal, natural gas, and electricity prices. These forecasts are summarized in Table 20. The coal prices in Table 20 are a blend of short-term prices based on market quotes and a long-term price forecast developed by Wood Mackenzie, an energy and mining research and consulting firm. Beyond the fourth forecast year, coal prices are based entirely on the Wood Mackenzie forecast. The natural gas forecast was developed by PIRA, an energy consulting firm. Electricity prices beyond 2015 are developed by the Companies using a software product called Aurora. Aurora simulates wholesale electricity prices in a competitive energy market. Aurora is a fundamental model that reflects the economics and physical characteristics of demand and supply. Through 2015, electricity prices are based on market forward prices as of March 14, 2011. The coal prices were developed in 2010; the natural gas and electricity prices were developed in 2011.

Table 20 – Coal and Natural Gas Prices ($/mmBtu)[22]

	Analysis of RFP Responses		
Year	High Sulfur Coal	Natural Gas	Electricity
2011	[redacted]		
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			

Table 21 and Table 22 contain four sets of more recently developed price forecasts. Each set of forecasts was developed in 2011. The '2011 Wood Mac/PIRA' price forecasts are updated versions of the forecasts used in the 2011 Resource Assessment; the longer-term coal forecast was developed by Wood Mackenzie and the longer-term gas price forecast was developed by PIRA. Wood Mackenzie and PIRA, respectively, also produce natural gas and coal price forecasts. The '2011 Wood Mac' forecasts reflect Wood Mackenzie's outlook for high sulfur coal and natural gas prices; the '2011 PIRA' forecasts reflect PIRA's outlook for high sulfur coal and natural gas prices.

[22] The information from PIRA and CERA in Tables 20, 21, and 22 is being provided pursuant to the Companies' Petition for Confidential Protection.

The differences between the 2011 Wood Mac coal forecast and the 2011 Wood Mac/PIRA coal forecast are explained by the fact that the Companies' contracted position is not factored into the shorter-term portion of the 2011 Wood Mac coal forecast. Likewise, the differences between the 2011 PIRA gas forecast and the 2011 Wood Mac/PIRA gas prices are explained by the fact that the market forward gas prices are not factored into the shorter-term portion of the 2011 PIRA gas forecast. With the exception of electricity prices through 2016, the '2011 CERA' price forecasts were developed by CERA. Through 2016, the 2011 CERA electricity prices are based on market forward prices as of March 14, 2011. The 2011 Wood Mac/PIRA electricity prices beyond 2016 were developed in Aurora. Through 2016, the 2011 Wood Mac/PIRA electricity prices are based on market forward prices as of June 17, 2011.

Table 21 – Alternative Commodity Price Forecasts ($/mmBtu)

	2011 Wood Mac/PIRA			**2011 CERA**		
Year	**High Sulfur Coal**	**Natural Gas**	**Electricity**	**High Sulfur Coal**	**Natural Gas**	**Electricity**
2012	[redacted]					
2013	[redacted]					
2014	[redacted]					
2015	[redacted]					
2016	[redacted]					
2017	[redacted]					
2018	[redacted]					
2019	[redacted]					
2020	[redacted]					
2021	[redacted]					
2022	[redacted]					
2023	[redacted]					
2024	[redacted]					
2025	[redacted]					

Table 22 – Alternative Commodity Price Forecasts ($/mmBtu)

Year	2011 Wood Mac		2011 PIRA	
	High Sulfur Coal	Natural Gas	High Sulfur Coal	Natural Gas
2012	[redacted]			
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				

The coal forecasts from Wood Mackenzie and PIRA are very comparable. As a result, the relationships between coal and natural gas prices in the 2011 Wood Mac/PIRA and 2011 PIRA forecasts are consistent. Compared to the Resource Assessment prices, the average margin between coal and natural gas prices in these forecasts narrowed by approximately 2% (from $5.10/mmBtu to $5.00/mmBtu). This margin is 16% lower in the 2011 Wood Mac forecasts and 39% lower in the 2011 CERA forecasts (compared to the Compliance Plan prices). The 2011 CERA coal prices are consistent with the 2011 Wood Mackenzie and PIRA coal prices. However, the Wood Mackenzie and CERA gas forecasts are lower than the PIRA gas forecast.

The Companies evaluated the options considered in the final Phase II analysis using the 2011 Wood Mac/PIRA forecasts and the 2011 CERA forecasts.[23] The results of these analyses are summarized in Appendix G – Updated Final Phase II Analysis: Commodity Price Scenario Results. Based on the 2011 Wood Mac/PIRA price forecasts, the Companies' findings are unchanged. The 'SB 2X1 (640) + 3 CTs (Sale – 2012)' alternative is the least-cost alternative in both the 'no economy purchases' and 'limited economy purchases' cases.

[23] The Companies evaluated the options under these price forecasts because – among the alternative price forecasts – the average margin between gas and coal prices is largest in the 2011 Wood Mac/PIRA forecasts and smallest in the 2011 CERA forecasts.

Based on the 2011 CERA prices, the PVRR difference between the top two alternatives (both of which include the same assets) narrows substantially. In the 'no economy purchases' case, the 'SB 2X1 (640) + 3 CTs (Sale – 2012)' alternative is still the least-cost alternative. In the 'limited economy purchases' scenario, the 'SB 2X1 (640) + 3 CTs (Sale – 2012)' alternative is only slightly below the 'SB 2X1 (640 MW) + 3 CTs (PPA – 2015)' alternative.

7.2 Load Forecast

In June 2011, the Companies developed the 2012 load forecast as part of its annual planning process ("2012 Forecast"). Table 23 compares the new load forecast to the load forecast used in the RFP analysis through 2025. Compared to the forecast used in the RFP analysis, the growth in peak demand in the new load forecast is lower (CAGR of 0.8% versus 1.4%).

Table 23 – Load Forecasts – After Reductions for DSM and Curtailable Load

	Summer Peak Demand (MW)			Annual Energy Requirements (GWh)		
Year	2011 IRP/ECR/RFP Forecast	2012 Forecast	Difference	2011 IRP/ECR/RFP Forecast	2012 Forecast	Difference
2012	6,821	6,930	109	36,271	35,898	(374)
2013	6,915	6,968	53	36,741	36,194	(547)
2014	6,976	7,004	28	37,057	36,299	(758)
2015	7,059	7,039	(20)	37,537	36,582	(955)
2016	7,070	7,121	51	37,985	36,961	(1,024)
2017	7,135	7,164	29	38,362	37,268	(1,094)
2018	7,234	7,223	(11)	38,872	37,625	(1,247)
2019	7,393	7,272	(121)	39,510	37,981	(1,529)
2020	7,546	7,372	(174)	40,162	38,411	(1,751)
2021	7,616	7,415	(201)	40,707	38,718	(1,989)
2022	7,704	7,533	(171)	41,344	39,066	(2,278)
2023	7,819	7,579	(240)	41,918	39,406	(2,511)
2024	8,008	7,629	(379)	42,646	39,845	(2,800)
2025	8,156	7,710	(446)	43,290	40,215	(3,075)

The Companies evaluated the options considered in the final Phase II analysis based on the 2012 Forecast and the 2011 Wood Mac/PIRA price forecasts. The results of this analysis are summarized in Appendix H – Updated Final Phase II Analysis: New Load Forecast Results. In this scenario, the 'SB 2X1 (640) + 3 CTs (Sale – 2012)' alternative is the least-cost alternative in both the 'no economy purchases' case and the 'limited economy purchases' case.

7.3 Least-Cost Alternative Conclusion

Based on the RFP and self-build analysis, the 'SB 2X1 (640) + 3 CTs (Sale – 2012)' alternative is the least-cost alternative for meeting the future capacity and energy needs of the Companies. This alternative is least cost in the base case scenarios as well as all but one of the alternative price scenarios.[24] In addition, the recommended option is the least-cost alternative in the updated load scenario as well.

[24] In the price scenario where this option is not least-cost, its PVRR is not significantly different from the least-cost option ($2 million).

Acquiring the Bluegrass CTs in 2012 will help the Companies manage potential development risks for the Cane Run CCCT as well as potential reliability risks associated with prudently managing the cost of maintenance at the Cane Run, Green River, and Tyrone stations as these units approach retirement. Furthermore, the proposed time period between the issuance of the final HAPs rule and being in compliance is three years. The Companies have assumed that this period will be extended by one year at the request of the permitting authority. The Bluegrass units will help the Companies manage the risk of this extension being denied by the permitting authority.

For these reasons, the least-cost alternative for meeting the future capacity and energy needs of the Companies is to build a 640 MW 2X1 CCCT at the Cane Run site ("Cane Run 7" or "CR7") and purchase the existing Bluegrass SCCT facility in La Grange, Kentucky from LS Power.

8 Current Project Descriptions and Costs

The following section summarizes the scope and cost of the proposed self-build 2X1 CCCT unit and the LS Power Bluegrass CTs.

8.1 Preferred Self-Build Option

8.1.1 Project Scope

The project scope includes all work necessary to construct a 640 MW net summer rating CCCT at Cane Run prior to January 1, 2016, including an 8.1 mile gas pipeline from Texas Gas at Penile Road to the Cane Run Site. The scope and estimates are based on F-class gas turbine technology for the natural gas CCCT plant.

F-class gas turbine technology provided the basis of an air permit application filed on June 13, 2011, with the Louisville Metro Air Pollution Control District (APCD). By utilizing the emissions from the existing Cane Run 4-6 to be shut down, the new CCCT was able to "net out" of the Prevention of Significant Deterioration permitting requirements. Receipt of all environmental permits necessary for construction is anticipated prior to the 3rd quarter of 2012. Significant delays of the permits required to commence construction will delay commercial operation beyond the best case required date of January 1, 2016.

HDR has been selected as the Owner's Engineer to support the engineering efforts throughout 2011 to optimize the design of the natural gas CCCT plant, including environmental permitting. HDR will assist the Utilities in their procurement efforts in 2012. Based on the current plans, purchase orders for long lead time equipment are scheduled to be issued upon receipt of required regulatory and environmental approvals, consistent with a construction schedule to meet the EPA-driven time requirements.

Energy Management and Services Company performed a route selection study for a gas pipeline to serve the Cane Run CCCT. They recommended an approximately eight mile route mostly along existing electric Rights of Way (ROW). EN Engineering surveyed the recommended route and confirmed construction feasibility. Additional archeological and geotechnical studies along the proposed ROW continue. Approximately 900 feet of new ROW parallel to Penile Road and an existing gas ROW will be required. Also, approximately two miles of gas pipeline ROW will be required within existing electric easements. Finally, a site for the Texas Gas delivery point at Penile Road will be required. The cost estimated for a 20" diameter line, adequate to serve the planned 640 MW CCCT is included in the $583 million overall cost estimate. The Companies' Gas Engineering staff will manage the pipeline construction for the project. Construction of the pipeline is scheduled in 2014.

Texas Gas will provide interstate gas transportation for the Cane Run CCCT. Texas Gas currently has firm transportation available in 2016 and has offered to provide service under their Summer No-Notice and Winter No-Notice tariff rate schedules. The optimal transportation volume has not yet been determined, but the annual fixed cost component of the transportation is expected to range from $11 - $16 million plus a variable cost of $0.03/mmBtu and a fuel loss of 3.56%. The current offer by Texas Gas reflects an annual discount of 27.5% from the maximum tariff rate or approximately $4 million annually. In addition, the offer includes:

- A minimum delivery pressure of 550 psig.
- Texas Gas' commitment to pay for the capital expenditures incurred in the installation of a new meter station (estimated value of $2 million).
- An evergreen provision and contractual right of first refusal.

To ensure firm transportation service is available from Texas Gas to serve the Cane Run CCCT, execution of a contract is anticipated in the 3rd quarter of 2011 provided a satisfactory regulatory out provision can be included in the contract. Texas Gas is currently seeking a tariff revision to allow the inclusion of regulatory out provisions in contracts that will require a 10 year contractual obligation to qualify.

As required by the Companies' OATT, a Large Generator Interconnection Feasibility Study (Feasibility Study) was requested from Southwest Power Pool (SPP) on June 3, 2011. The Feasibility Study results should be available in September. While electric transmission upgrades are expected to be required, a Transmission CCN application is not anticipated. Once a Large Generator Interconnection Agreement (LGIA) is signed in 2012, the Transmission Owner will be responsible for developing and constructing any necessary transmission system upgrades. The Companies' Transmission staff conducted an analysis of upgrades necessary for delivering energy from the Cane Run CCCT to load. Transmission projects identified in the Companies' analysis include installation of a transformer, generator breakers, switches, re-conductoring, and relocation of some transmission structures and conductors. The analysis, including cost estimates, attempts to identify the transmission work expected from the required SPP studies. Key remaining project milestones for 2011 include:

- Option Gas Pipeline ROW — August
- Execute Texas Gas Transportation Contract — August
- File Generation CCN Application — September
- Qualify Equipment Suppliers and Constructors — December

8.1.2 Project Cost

The total project cost is expected to be $583 million for generation and $34 million for electric transmission upgrades to construct a 640 MW net summer rating CCCT at Cane Run for January 1, 2016, commercial operation. No costs of decommissioning Cane Run 4-6 are included in the estimate. This estimate includes contingency of approximately 10% of the expected EPC cost. The estimated project costs were determined in a site specific study dated March 15, 2011, assuming owner furnished major equipment assigned to an Engineer, Procure & Construction (EPC) contractor. The estimate includes $12 million for capitalized spare parts. Table 24 summarizes the project capital costs by year.

Table 24 – Cane Run CCCT Capital Costs ($Millions)

	2011	2012	2013	2014	2015	2016	Total
640 MW CCCT (Q4 2015 COD)	3	42.7	156.7	222.8	144.6	13.2	583
Cane Run Transmission	0	0	0	0	14.2	20.2	34
Totals	**3**	**42.7**	**156.7**	**222.8**	**158.8**	**33.4**	**617**

The capital cost estimate is based on major equipment budgetary quotations and HDR's project data base. Major equipment (gas turbine, heat recovery steam generator, and steam turbine) budgetary quotations from multiple suppliers were received in February of 2011. HDR evaluated the budgetary quotes and compiled a Level I Conceptual Cost Estimate in March 2011. The market for new domestic power generation equipment is currently considered weak. EPA's regulatory changes such as Utility MACT will likely increase the demand for combined cycle equipment. The timeline for equipment demand is dependent on the rate of retirement for aged coal assets and gross domestic product growth. There has been a small up-tick in commodity pricing over the last six months consistent with the three to four percent escalation contained in the materials and construction estimates. The project also carries a ten percent contingency of the expected EPC costs. Major market shifts, such as a "dash to gas" or labor shortage due to environmental compliance projects, could cause the cost estimate to be exceeded.

8.2 Bluegrass CTs

8.2.1 Bluegrass Plant Description

The optimized expansion plan to meet the Companies' 2016 need includes the acquisition of the assets of the 495 MW BGC after regulatory approvals are obtained in 2012 and the construction of a 640 MW CCCT at the Cane Run Site.

The Bluegrass Plant entered service in June of 2002. It contains three Siemens-Westinghouse 501 FD2 combustion turbines in simple cycle. The combustion turbines provide 495 MW of summer capacity. Since commercial operation each unit has accumulated approximately 1000 operating hours and 340 starts.

The Bluegrass Plant and its 60 acre site are leased from Oldham County as a means to fix property taxes at a known value. The plant and the land can be purchased for $1 at the end of the lease term in December 2025. LS plans to terminate the lease structure prior to closing.

The plant is electrically interconnected to the Utilities' transmission system at 345 kV. Additional studies will be required to determine the extent of upgrades that may be necessary to move the Bluegrass generation to the Utilities' load. The Companies' Transmission staff conducted analysis of adding the Bluegrass units as Designated Network Resources, in addition to the Cane Run natural gas CCCT. The analysis, including cost estimates, attempts to identify the transmission work expected from the required SPP studies.

The total estimated cost of all electric transmission projects which may be required by 2016 or earlier to support both the Cane Run CCCT and the three Bluegrass units is $39 million. This $39 million estimate includes projects totaling approximately $5 million for the Bluegrass units and projects totaling approximately $34 million as indicated above for the Cane Run CCCT.

Interstate gas transportation to the plant is provided by Texas Gas on an interruptible basis. Firm gas transportation for the plant is anticipated to be purchased from Texas Gas as Utility capacity needs require the continuous availability of the Bluegrass Plant.

The Bluegrass air permit limits NO_x to 95 tons per year and CO to 245 tons per year. The plant should be able to operate approximately 1,000 hours per year under the permit limits which is significantly more than the anticipated operating hours for the peaking units. The expected maximum allowable operating hours will be confirmed during due diligence.

At the proposed purchase price of $110 million, the resulting unit price for summer capacity is $222/kW. This cost is less than 30% of the cost of a green field SCCT in the 2011 IRP.

9 Utility Ownership Allocation

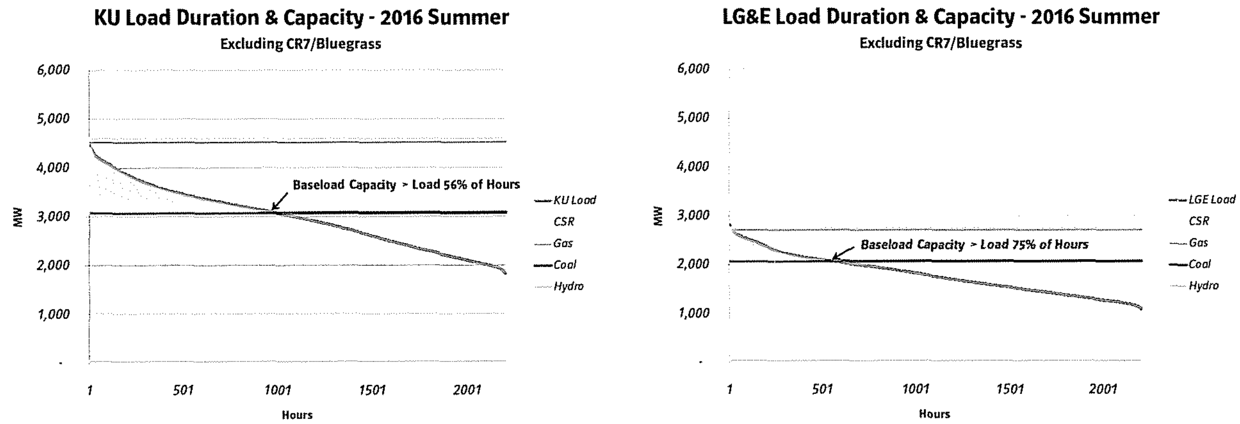
9.1 Background

Since the merger of LG&E and KU, the Companies have commissioned eleven jointly-owned units: ten CTs at the Trimble County, E. W. Brown, and Paddy's Run stations and the Trimble County 2 coal unit (TC2). An ownership ratio for the jointly-owned CTs was determined so that each utility's projected reserve margin was equalized in the in-service year. Since TC2 was expected to result in significant energy savings to the Companies, its ownership split was based on the expected energy benefits to each company. To determine these benefits, the production costs associated with the Companies' existing generation portfolio and 30-year least-cost expansion plan (including TC2) were compared to the production costs associated with its generation portfolio and a 30-year expansion plan that included only CTs. This "all-CT" expansion plan represented the least-cost expansion plan when only considering capacity needs. The overall least-cost plan included TC2 and was expected to result in significant energy savings over the "all-CT" plan. Since each company was expected to benefit differently from constructing the TC2 plan due to each company's unique load profile and existing generation mix, TC2's ownership split was determined based on each company's share of the net present value of production cost savings.

9.2 Energy and Capacity Needs

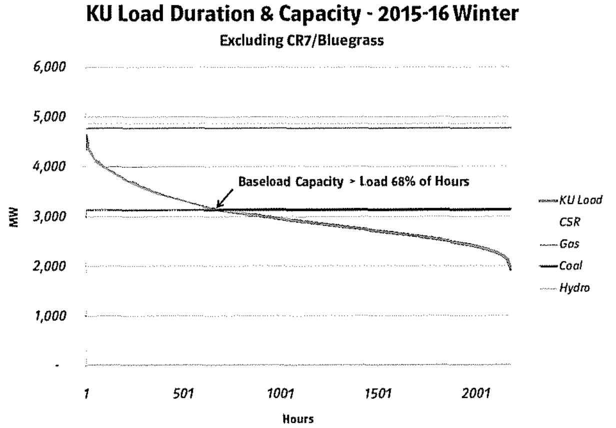
KU and LG&E have different load profiles and will have different levels of baseload capacity available to meet their individual energy needs. Figure 2 shows that KU's baseload capacity is expected to be greater than its 2016 summer load 56% of the time, while LG&E is expected to have sufficient baseload capacity in 75% of the summer hours. This data demonstrates that KU has a greater summer energy need compared to LG&E.

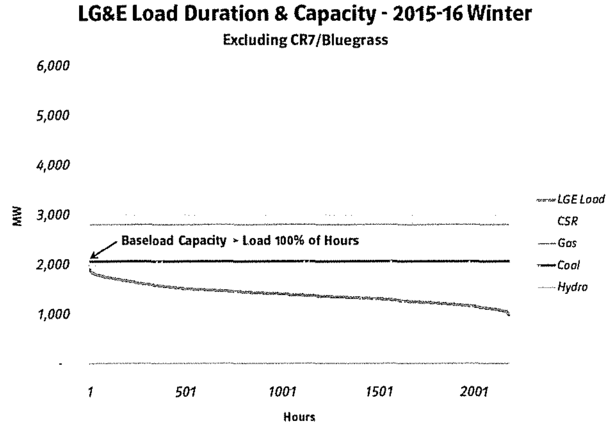
Figure 2 – Summer Energy Needs



KU's load peaks in both the summer and winter months, resulting in a winter energy need forecasted for KU, as shown in Figure 3. LG&E does not have a winter peak and therefore has sufficient baseload capacity to meet its load.

Figure 3 – Winter Energy Needs





After the proposed retirements in 2016, the Companies' individual reserve margins will drop well below the target system reserve margin of 16%. Table 25 shows the individual company reserve margin needs at summer peak that would be expected without the addition of new capacity. This table demonstrates that KU's reserve margin need is expected to quickly outpace that of LG&E.

Table 25 - Individual Summer Reserve Margin Needs[25]

MW	2016	2017	2018	2019	2020
KU	486	576	556	684	761
LG&E	503	469	552	488	527

KU's greater energy and capacity needs suggest that KU requires a larger share of the more efficient 2X1 CCCT unit and a larger share of the total capacity addition.

9.3 Methodology

The combined cycle unit is expected to operate at approximately a 40% capacity factor generating significant amounts of energy, therefore the Companies calculated its ownership using a method similar to the method used for TC2 as described in Section 9.1 so that the CCCT's energy benefits are matched to its ownership split. The Bluegrass CTs are expected to operate at capacity factors less than 5%. Therefore, their ownership split was calculated to balance each utility's reserve margin, given the CCCT ownership share. The individual reserve margins were balanced by first identifying each company's peak load in the five year period between 2016 and the next planned capacity addition in 2021. The ownership of the Bluegrass CTs was then calculated to balance the reserve margin at these individual utility peaks. Since the ownership splits of the CCCT and the Bluegrass CTs are interdependent with this method, an iterative process was used to find the appropriate combination of ownership allocations.

9.4 Optimal Ownership

The optimal ownership split of the Cane Run CCCT is KU owning 78% and LG&E owning 22%, while KU should own 31% and LG&E 69% of the Bluegrass CTs. This method balances the production cost savings of the CCCT and balances the company's individual reserve margins through 2020.

[25] Load and capacity figures are based on data developed as part of the 2012 planning cycle.

10 Final Conclusions

Based on the RFP and self-build analysis, the least-cost alternative for meeting the future capacity and energy needs of the Companies is to build a 640 MW 2X1 CCCT at the Cane Run site CR7 and purchase the existing Bluegrass SCCT facility in La Grange, Kentucky from LS Power. To effectuate this plan, the Companies will need to make appropriate regulatory filings for these generating resources. While not anticipated based on the initial electric transmission upgrade assessments, should regulatory approvals be required for any related transmission facilities, appropriate and timely filings will be made. The resources are needed to replace capacity that will be retired at the end of 2015 and to meet the anticipated load growth in the Companies' service territories. Specifically, the resources include:

i. the construction of the Cane Run 640 MW 2X1 natural gas CCCT project (to be permitted as Cane Run 7) and any related electric and gas transmission facilities needed to deliver CR7 energy to load prior to January 1, 2016.

ii. the purchase from LS Power of the existing SCCTs at its Bluegrass facility in La Grange, Kentucky and any related transmission facilities needed to deliver the associated energy to load. The Bluegrass CTs would be available during 2012.

The timeline for constructing the CR7 unit is constrained by the need to have the unit operational prior to January 1, 2016, when the retirement of approximately 800 MW of coal-fired capacity at Cane Run, Tyrone, and Green River is planned due to impending EPA regulations.

The purchase of the existing Bluegrass facility from LS Power is needed to meet the same deadlines and need. The existing facilities at Bluegrass are already in operation. An agreement with LS Power will enable purchase in 2012. These assets will be available during the construction of the CR7 project to mitigate development risks as well as operational risks associated with the retiring coal units as their maintenance expenses are minimized ahead of retirement in the interest of prudently managing costs.

11 Appendices

11.1 Appendix A – Phase I Screening Results

Response Number	Technology	Respondent	Description	Transmission Interconnection Point	Summer Nominal Capacity	Start Date	Term (Years)	Transmission Upgrades ($M)	Transmission Outside Control Area ($/kW-mth)	Firm Summer Capacity	Levelized Costs $RR/MWh	Levelized Costs $/Firm kW-Year	Rank
13I	[redacted]												1
13H													2
13J													3
13G													4
4													5
12													6
9													7
1A													8
1B													9
2B													10
2A													11
17													12
15													13
13E	[redacted]												1
13D													1
13F													3
13B													4
13A													4
13C													6
5A	[redacted]												1
5B													2
14B													3
22	[redacted]												1
20B													NA
20A													NA
6A	[redacted]												1
14A													2
10													3
11													4
6B													5
6D													6
7A													7
8A													8
7B													9
7C													10
7D													11
6C													12
6E													13
8B													14
8C													15
6F													15
18	[redacted]												1
21A	[redacted]												1
21B													2
16A	[redacted]												1
16B													2
16C													3
3													4

11.2 Appendix B – Key Assumptions

- Study Period:
  30-year period for Production Cost impacts (2011-2040)
  30-year period for Capital Costs impacts (2011-2040)

- The Companies continue as regulated entities subject to the oversight of the Kentucky Public Service Commission and the Commission continues to require the Companies to implement least-cost strategies to the benefit of the native load ratepayers.

- The capital costs, O&M costs, and the costs of increased emissions (both NOx and SO_2) associated with the addition of new environmental projects will be subject to recovery through the Environmental Cost Recovery mechanism.

- Fuel Forecast (Base Assumptions)
  Any and all fuel cost savings associated with serving native load will be returned to the ratepayers though the Fuel Adjustment Clause mechanism.

- Load Forecast is taken from the 2011 Integrated Resource Plan.

- Financial Assumptions:

LG&E/KU Discount Rate (%):	6.71 %
Federal Income Tax Rate (%)	38.90 %
Insurance Rate (%):	0.07 %
Property Tax Rate (%):	0.15 %
Percentage of Debt in Capital Structure (%):	46.52 %
Weighted Cost of Debt (%):	3.84 %
Return on Equity (%):	10.5 %

11.3 Appendix C – Preliminary Phase II Analysis Results

Preliminary Phase II Analysis - Base Case Prices

	PVRR ($M)							
	Production Costs	Capital	Gas Trans.	Fixed O&M	Capacity Charge	Elec Trans.	Grand Total	Difference from Best Option
No Economy Purchases								
[redacted]								
Limited Economy Purchases								
[redacted]								

Note: 'SB' stands for self-build; 'CTs' refer to Bluegrass CTs.

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Preliminary Phase II Analysis - CERA Prices

	PVRR ($M)							
	Production Costs	Capital	Gas Trans.	Fixed O&M	Capacity Charge	Elec Trans.	Grand Total	Difference from Best Option
No Economy Purchases								
[redacted]								
Limited Economy Purchases								
[redacted]								

Note: 'SB' stands for self-build; 'CTs' refer to Bluegrass CTs.

11.4 Appendix D – Summary of Final Phase II Alternatives

Summary of 2011 RFP Options

									Capacity Charge	Energy Price		Variable O&M			Transmission		
RFP #	Description	Start Date	Term (Years)	Firm/Net Delivered Capacity (MW)	Heat Rate (Btu/kWh)	Asset Sale/ Construction Cost ($M)[1]	Fixed O&M ($/MW-yr)	Firm Gas Transport ($/MW-Yr)	Fixed ($000/MW-Yr)	Energy Price ($/MWh)	Esc (%)	General ($/MWh)	Start cost ($000)	Fuel (mmBtu/ start)	XM Capital ($M)[1]	XM ($000/ MW-yr)	FOR
13C	[redacted]																
13F	[redacted]																
13C	[redacted]																
13C	[redacted]																
13E	[redacted]																
13E	[redacted]																
13E	[redacted]																
13C	[redacted]																
5B	[redacted]																
4	[redacted]																
13C	[redacted]																
12	[redacted]																
13E	[redacted]																
13J	[redacted]																
NA	[redacted]																
12	[redacted]																
4	[redacted]																
13E	[redacted]																

Note: Numbers in bold are in 2011 dollars; numbers not in bold are in start date year dollars.

[1] Asset Sale / Construction Costs and XM Capital are the sum of nominal (as-spent) dollars.

[2] Startup Cost per gas turbine

11.5 Appendix E – Final Phase II Analysis Results

Final Phase II Analysis - Base Case Prices

	PVRR ($M)							
	Production Costs	Capital	Gas Trans.	Fixed O&M	Capacity Charge	Elec Trans.	Grand Total	Difference from Best Option
No Economy Purchases								
[redacted]								
Limited Economy Purchases								
[redacted]								

Note: 'SB' stands for self-build; 'CTs' refer to Bluegrass CTs.

11.6 Appendix F – Updated Final Phase II Analysis Results

Updated Final Phase II Analysis - Base Case Prices

	PVRR ($M)							
	Production Costs	Capital	Gas Trans.	Fixed O&M	Capacity Charge	Elec Trans.	Grand Total	Difference from Best Option
No Economy Purchases								
[redacted]								
Limited Economy Purchases								
[redacted]								

Note: 'SB' stands for self-build; 'CTs' refer to Bluegrass CTs.

11.7 Appendix G – Updated Final Phase II Analysis: Commodity Price Scenario Results

Updated Final Phase II Analysis - 2011 Wood Mac/PIRA Prices

	PVRR ($M)							
	Production Costs	Capital	Gas Trans.	Fixed O&M	Capacity Charge	Elec Trans.	Grand Total	Difference from Best Option
No Economy Purchases								
[redacted]								
Limited Economy Purchases								
[redacted]								

Note: 'SB' stands for self-build; 'CTs' refer to Bluegrass CTs.

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Updated Final Phase II Analysis - 2011 CERA Prices

	PVRR ($M) Production Costs	Capital	Gas Trans.	Fixed O&M	Capacity Charge	Elec Trans.	Grand Total	Difference from Best Option
No Economy Purchases								
[redacted]								
Limited Economy Purchases								
[redacted]								

Note: 'SB' stands for self-build; 'CTs' refer to Bluegrass CTs.

11.8 Appendix H – Updated Final Phase II Analysis: New Load Forecast Results

Updated Final Phase II Analysis - 2011 Wood Mac/PIRA Prices w/ 2012 Load Forecast

	NPVRR ($M)							
	Production Costs	Capital	Gas Trans.	Fixed O&M	Capacity Charge	Elec Trans.	Grand Total	Difference from Best Option
No Economy Purchases								
[redacted]								
Limited Economy Purchases								
[redacted]								

Note: 'SB' stands for self-build; 'CTs' refer to Bluegrass CTs.

2011 RESOURCE ASSESSMENT
ERRATA SHEET

In addition to the correction of Table 20 and the inclusion of information from CERA and PIRA, the 2011 Resource Assessment contains a limited number of non-substantive changes to ensure consistency with the underlying analysis. The underlying analysis has not changed in any way. A summary of all the changes to the 2011 Resource Assessment follows:

1. Section 7.1
    a. Page 26, 1st paragraph.
        i. Replaced "is also a blended forecast. The first three years of the forecast are based on market quotes. Gas prices beyond the third year were" with "was."
        ii. Added "beyond 2015" and "Through 2015, electricity prices are based on market forward prices as of Month DD, YYYY" to clearly indicate the way market forward prices are included in the electricity price forecast in Table 20.
    b. Page 26, Table 20.
        i. Provided previously redacted natural gas price forecast beyond 2013.
        ii. Updated gas prices for 2011 through 2013. The Companies had inadvertently pasted gas prices from the 2011 Compliance Plan into the table.
    c. Page 26, 2nd paragraph. Replaced "Compliance Plan" with "Resource Assessment."
    d. Page 26, Footnote 22. Updated footnote to reflect the fact that the information from PIRA and CERA in Tables 20, 21, and 22 is being provided pursuant to the Companies' Petition for Confidential Protection.
    e. Page 27, 1st paragraph. Added language at the end of the paragraph to clearly indicate the way market forward prices are included in the electricity price forecasts in Table 21.
    f. Page 27, Table 21.
        i. Provided previously redacted 2011 Wood Mac/PIRA natural gas price forecast beyond 2014.
        ii. Provided previously redacted 2011 CERA price forecasts.
    g. Page 28, Table 22. Provided previously redacted 2011 PIRA forecasts.
    h. Page 28, 1st paragraph. Updated text to be consistent with changes to Table 20.
        i. Replaced "Compliance Plan" with "Resource Assessment."
        ii. Replaced "15%" and "$5.90" with "2%" and "$5.10."
        iii. Replaced "28%" and "47%" with "16%" and "39%."
2. Appendix D – Summary of Final Phase II Alternatives
    a. Changed Start Date for RFP response #13C from 1/1/2012 to 6/1/2012.
    b. Changed Firm/Net Delivered Capacity (MW) for RFP response #13E from 495 to 330.
    c. Added Capacity Charge for RFP responses #13E and #13F.
    d. Added one clarifying footnote (footnote 2).

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 18

Witness: David S. Sinclair

Q-18. Refer to the 2011 Resource Assessment, Table 12, at page 18. Several of the options in the table appear to have a combination of alternatives grouped together. Explain why such options were grouped in this manner.

A-18. The Companies' need for capacity in 2016 is 877 MW (see Table 1 at page 4 of the 2011 Resource Assessment – Exhibit DSS-1). Because capacity additions of less than 600 MW do not defer the need for additional capacity in 2016, the Companies considered various RFP responses in combination. Several options were considered in combination with the Bluegrass SCCTs from LS Power because at capital cost of approximately \$220/kW, the Bluegrass SCCTs are priced very competitively.

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Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 19

Witness: David S. Sinclair

Q-19. Refer to the 2011 Resource Assessment at pages 19-22.

a. Explain what economy market purchases mean in the context of the analysis.

b. Provide the source of base case scenario natural gas and electricity prices and explain how these prices are different from those provided by CERA.

c. Explain why off system sales were not allowed in the analysis.

d. Provide a detailed explanation and the results of the analysis that demonstrate why LS Power's simple cycle combustion turbine ("SCCT") options go forward into the final phase analysis and LS Power's CCCT are a higher cost than the CCCT self-build option. Include in the discussion the specific factors that pushed the analysis results toward the self-build option.

e. In Table 16, of the four least-cost options, the 640 MW option is lower cost than either the 690 MW option or the 605 MW option. Explain the differences between these options, i.e., if the production cost savings associated with the 690 MW option do not outweigh its additional capital and gas transportation costs as compared to the 640 MW option, explain why the same does not hold true for the 640 MW option versus the 605 MW option.

f. Table 16 lists Purchased Power Agreements ("PPAs") starting in 2015, but sales beginning in 2012. Explain to what extent beginning the PPAs in 2012 makes a difference in the cost analysis.

A-19.

a. 'Economy market purchases' refers to the purchase of power in the hourly power market. In the analysis, economy purchases are limited by modeled transmission constraints (please see response to Question No. 23(c)).

b. The base case scenario natural gas prices are from PIRA as of February 2011. Electricity prices are developed by the Companies using a software product called AURORAxmp, a proprietary wholesale market analysis software produced by EPIS Inc. The AURORAmap software uses the base scenario natural gas price as an input.

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[redacted]

c. The level of off-system sales is highly dependent on future market electricity prices. Consistent with past evaluations of new sources, the Companies are not proposing any projects that are justified by speculating on future market electricity prices. The analysis in the 2011 Resource Assessment considered each option's impact on the Companies' ability to serve native load only.

d. Please see the response to Question No. 18. The Bluegrass SCCTs were considered in the final Phase II analysis because of the value they add in combination with other options. The Bluegrass SCCTs are less than one-third of the cost of a self-build SCCT, but the Bluegrass CCCT options are more than two-thirds of the cost of the comparable self-build CCCT options. Clearly, if the Bluegrass SCCTs are converted to a CCCT, the option to pair the SCCTs with another alternative is lost. For these reasons, the self-build CCCT options (in combination with the Bluegrass SCCTs) are more valuable than the Bluegrass CCCT options in combination with other alternatives.

e. In three of the four alternatives, the Companies' self-build CCCT options are paired with the purchase of the Bluegrass CTs in 2012. In the other alternative, the 640 MW CCCT is paired with the PPA for the Bluegrass CTs starting in 2015. In addition to capital cost, the differences between these alternatives are driven by the different capacities of the self-build options and the associated impacts on production costs and expansion plans. All other things equal, more CCCT capacity reduces the need for SCCT energy and reduces overall production costs; less CCCT capacity ultimately results in the need for additional capacity sooner. The capital cost of the 605 MW option is $2.2 million lower than the 640 MW option. However, due to its smaller size, the 605 MW option creates the need for additional capacity in 2019, one year sooner than the 640 MW option. The relatively small difference in capital cost between the 605 MW and 640 MW option is more than offset by the costs associated with needing additional capacity sooner.

Arguably, the capacity difference between the 605 and 640 MW self-build options (35 MW) should result in relatively small differences between each option's expansion plan. Therefore, in the updated final Phase II analysis with 2011 Wood Mac/PIRA commodity prices and the new load forecast (see Section 7.2 of the 2011 Resource Assessment at page 29), the Companies assumed that the timing of the first additional unit in the expansion plan for each option is the same. With this change, the relatively small difference in capital cost between the 605 MW and 640 MW option is still more than offset by the costs associated with needing additional capacity sooner (albeit later in the analysis period).

f. For a given alternative, beginning the PPA in 2012 (versus 2015) increases the revenue requirements of the alternative. The costs of the PPA in 2012-2014 more than offset the production cost savings associated with the additional capacity during this period.

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Response to the Commission Staff's First Information Request
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Case No. 2011-00375

Question No. 20

Witness: David S. Sinclair

Q-20. Refer to the 2011 Resource Assessment on page 24.

a. In addition to discounting the purchase price of the SCCT units, explain whether LS Power would have been willing to discount the purchase price of its CCCT units and whether LG&E approached LS Power with this option if proper terms could be achieved.

b. Provide a detailed explanation and list of the factors and factor values that changed to produce a lower capital cost estimate for the 640 MW CCCT units.

A-20.

a. The purchase price discount applied to the existing SCCT units. While it is reasonable to assume that the same discount might have applied to the existing assets as used in a potential combined cycle project, the Companies have no indication that LS Power would have discounted the additional project investment required to complete a combined cycle plant. Applying the same volume of discount to the combined cycle project would not change the attractiveness of the combined cycle project. The Companies did not pursue the combined cycle alternative, but believe there is no more likelihood for discount on the undeveloped portion of the proposed project than for any other yet-to-be-developed project.

b. The first set of capital cost estimates was expressed in nominal (as-spent) dollars, but the estimates were modeled as if they were expressed in 2010 dollars and escalated accordingly. As a result, the first set of estimates was over-escalated. The Companies corrected this mistake in the Updated Final Phase II Analysis and the modeled (nominal) capital cost decreased by $92 million.

The first capital cost estimate for the 640 MW NGCC was $570 million (in nominal dollars). The updated capital cost estimate is $583 million (in nominal dollars). The difference is explained by the following:

	($Millions)
Transmission line relocation on the Cane Run site	$ 3.0
Relocation of communication tower on Cane Run site	$ 0.4
Spare Parts LTSA cost moved from O&M to capital	$ 7.0
Property Tax during construction	$ 1.8
Increase in contingency	$ 0.6
Total increases	$12.8

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Response to the Commission Staff's First Information Request
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Case No. 2011-00375

Question No. 21

Witness: David S. Sinclair

Q-21. Refer to the 2011 Resource Assessment at pages 22-25. The reduced capital costs associated with the 640 MW self-build option listed in Table 18 do not seem to apply to the other self-build options. Provide a detailed explanation of why the Present Value Revenue Requirement for the other self-build options listed in Table 19 appear to be more expensive (i.e., shows a wider spread) than those listed in Table 16.

A-21. When the Companies' refined their capital cost estimate for the 640 MW self-build option after it was identified as part of the least-cost alternative in the final Phase II analysis, they also refined (and lowered) their estimates for the 605 MW and 690 MW self-build options. Compared to the final Phase II analysis results, the PVRR differences for the other self-build options in the updated final Phase II analysis range from $4 million lower to $11 million higher; the other self-build options in Table 19 are not necessarily more expensive. For example, with no economy purchases, the spread between the least-cost alternative and the 690 MW self-build option (in combination with the Bluegrass SCCTs) is $3 million lower in Table 19; the spread between the least-cost alternative and the 605 MW self-build option is unchanged.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Commission Staff's First Information Request Dated October 26, 2011

Case No. 2011-00375

Question No. 22

Witness: David S. Sinclair

Q-22. Refer to the 2011 Resource Assessment, Tables 20-21 at pages 26-27.

a. If CERA and PIRA data and the explanations regarding those data are not provided for examination, explain why the analysis should be accepted in this proceeding.

b. Explain whether or not CERA and PIRA and Wood MacKenzie provide any explanation and description of assumptions supporting the forecast data provided to the companies. If so, provide the written descriptions.

c. If the forecasts are significantly different than those published by the EIA or those used in the 2011 IRP, provide a detailed explanation of why LG&E and KU believe that these forecasts are materially more accurate than (1) what they used previously, or (2) forecasts from other published sources.

d. LG&E and KU used base case scenario natural gas prices in addition to the CERA and PIRA prices. Provide an update to Tables 20 and 21 with the base case scenario prices included.

e. Explain whether the natural gas prices used in the analysis are city gate prices or Henry Hub prices.

A-22.

a. IHS CERA ("CERA") and PIRA provide their forecasts on a proprietary basis to their clients. However, since the Companies filed their Joint Application, CERA and PIRA have provided permission to disclose information confidentially. Therefore, that information is being provided pursuant to the Companies' Petition for Confidential Protection filed contemporaneously herewith.

b. PIRA, CERA, and Wood Mackenzie do provide, on a proprietary basis, written documentation supporting their forecast data. The Companies have obtained permission to share the documents from PIRA and CERA discussed below. The Companies do not subscribe to Wood Mackenzie's natural gas service and therefore, explanations and descriptions of assumptions for this forecast are not available to the Companies.

In July 2010, CERA produced as a multi-client study a set of energy scenarios that provided three distinct views of the future of energy. The scenario named Global Redesign was identified as their planning scenario. Chapter II of this study was written as an "energy narrative" for this scenario. In the spring of 2011, CERA issued an update to these scenarios, which was the source of the "2011 CERA" forecasts shown in the Resource Assessment. CERA provided several overviews of the update, along with a workbook of updated gas forecast data. The following documents regarding CERA's forecast are attached on the CD in the folder titled Question No. 22:

- Chapter II document
- Overview of the scenario development
- Presentations describing the scenario updates
- Updated overview document
- Workbook of gas-related forecast data

PIRA hosts an annual retainer client seminar during which they present a long-term outlook on a variety of topics including natural gas. Various presentations addressing the North American natural gas outlook that were presented at the October 2010 seminar and a workbook of gas supply-demand balance forecasts are attached on the CD in a folder titled Question No. 22. In February 2011, PIRA provided on its website an updated long-term gas price outlook which was used by the Companies for the base case Resource Assessment. The views expressed in the October 2010 presentation reflect PIRA's broad outlook for the natural gas marketplace and would generally apply to the February pricing data.

The attachments on the CD in the folder titled Question No. 22 are being provided pursuant to a Petition for Confidential Protection.

c. While the forecasts from various sources are different, the differences are immaterial to the Companies' recommendations in this case. Because the lowest-cost new generation options considered are all gas-fueled, the differences between these gas price forecasts are inconsequential. The Companies cannot state that any forecast is "materially more accurate" than another. The guiding principle in the Companies' development of forecasts, both from an input as well as an output perspective, is that the forecast should represent a reasonable outlook. An important facet of a reasonableness test is whether the forecast in question adequately reflects the environment in which the Companies expect to operate.

In its Preface, the EIA's 2011 Annual Energy Outlook ("AEO") states:

> "*AEO2011* projections are based generally on Federal, State, and local laws and regulations in effect as of the end of January 2011. The

> potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections."

The AEO 2011 Reference Case does not incorporate estimated impacts of the Cross State Air Pollution Rule ("CSAPR"), coal ash regulation, HAPs standards, and cooling water rules, all of which impact the cost of coal-fired generation and encourage increased gas-based dispatch and investment in gas-fired generation, increasing the demand for natural gas. The AEO 2011 High Shale Case incorporated an increased domestic gas resource expectation, but also did not include the impending series of coal-related regulations. PIRA, CERA and Wood Mackenzie did reflect assumptions regarding these potential regulations in developing their gas price forecasts, making them more relevant forecasts given the expected regulatory environment. PIRA and CERA also incorporated expectations of an increased supply of recoverable gas resources. The Companies have only limited information on Wood Mackenzie's gas outlook, but included their price curve as an alternative view that Wood Mackenzie modeled in concert with their coal price outlook which the Companies adopt as their official long-term coal price forecast.

Another key factor that the Companies use to assess the reasonableness of an input forecast is evaluating its consistency with other assumptions that have been made in the planning process. In the 2011 IRP, the adopted long-term gas price forecast was produced by PIRA as of April 2010. For the 2011 Resource Assessment, the Companies adopted a February 2011 update by PIRA which maintained consistency in forecast source while also incorporating a significant decline in the path of long-term gas prices.

d. In the 2011 Resource Assessment, the Companies inadvertently copied the wrong natural gas prices into Table 20 on page 26. In the new confidential version of the document, Table 20 has been updated and the redacted information in Tables 20 and 21 has been provided.

e. The natural gas price forecasts used in the analysis are delivered prices, i.e. they include the cost to deliver the fuel to the Companies' generating units. The prices displayed in Tables 20, 21, and 22 of the 2011 Resource Assessment are shown as Henry Hub prices to facilitate direct comparison of the source forecasts used by the Companies.

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Response to the Commission Staff's First Information Request Dated October 26, 2011

Case No. 2011-00375

Question No. 23

Witness: David S. Sinclair

Q-23. Refer to the 2011 Resource Assessment at page 26.

a. Provide a detailed explanation of how Aurora models the supply and demand for electricity, the manner in which Aurora estimates electricity prices, and what other estimates are derived using that model.

b. Provide a description of the inputs used to obtain the electricity forecasts.

c. Provide a detailed explanation of how electricity price forecasts were used in the evaluation of RFP response options.

A-23.

a. AURORAxmp ("Aurora") is designed to model wholesale electricity prices in a competitive energy market. Aurora uses a fundamentals approach in estimating prices, reflecting the economics and physical characteristics of demand and supply. Aurora estimates prices by using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm. The operation of resources within the electric market is modeled to determine which resources are on the margin for each zone in any given hour.

The Companies modeled the Eastern Interconnect power grid in Aurora, considering that PJM market pricing zones are highly interconnected with other NERC reliability regions in the Eastern Interconnect. Aurora has a large database that includes zone definitions for all NERC reliability regions as well as transfer capabilities between market zones. Aurora uses this information to build an economic dispatch for every market zone. Units are dispatched according to variable cost, subject to non-cycling and minimum run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area.

For additional information on the Aurora model please see the more detailed description attached.

b. The electricity price forecasts developed in Aurora used several inputs including delivered fuel and emission prices, long-term energy demand forecasts, transmission interconnections, generating resources with corresponding operational parameters, and supply side resources including demand-side and price-induced curtailment functions, among others. Most of these inputs are used as provided by EPIS, the developer of the Aurora software, except for commodity prices.

   Coal price inputs are Wood Mackenzie's long-term price forecasts by basin, and natural gas prices are PIRA's long-term forecast at Henry Hub. The alternative 2011 CERA power price forecast was developed using CERA's forecast for coal prices and Henry Hub natural gas prices.

c. In each part of the Phase II analysis and for a given set of natural gas, coal, and electricity price forecasts, each alternative was evaluated under two economy market purchase scenarios: (1) no economy purchases and (2) limited economy purchases. In the limited economy purchases scenario, the electricity price forecast determines the cost of economy purchases.

AURORAxmp Logic

AURORAxmp is specifically designed to model wholesale electricity prices in a competitive energy market. In a competitive market, at any given time, prices should be based on the marginal cost of production. Prices will rise to the point of the variable cost of the last generating unit needed to meet demand. One of the principal functions of AURORAxmp is to estimate this hourly market-clearing price at various locations, including North America and Europe.

AURORAxmp uses a fundamentals approach in estimating prices, reflecting the economics and physical characteristics of demand and supply. AURORAxmp estimates prices by using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm. The operation of resources within the electric market is modeled to determine which resources are on the margin for each zone in any given hour.

The North American database includes zone definitions for all of the NERC reliability regions. The AURORAxmp database includes long-term average demand and hourly demand shapes for all the areas in the database. These demand areas are connected by transmission links with specified transfer capabilities, losses, and wheeling costs.

Existing supply-side generating units are defined and modeled individually with specification of a number of cost components and physical characteristics and operating constraints. Hydro generation for each area, with instantaneous maximums, off-peak minimums, and sustained peaking constraints are also input. Demand-side resources and price-induced curtailment functions are defined, allowing the model to balance use of generation against alternatives to reducing customer demand.

AURORAxmp uses this information to build an economic dispatch for the markets. Units are dispatched according to variable cost, subject to non-cycling and minimum run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market-clearing price for the power they generate.

AURORAxmp also has the capability to simulate the addition of new-generation resources and the economic retirement of existing units. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable; that is, when investors can recover fixed and variable costs with an acceptable return on investment. AURORAxmp uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

Existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas, the rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years.

In summary, to simulate the economic dispatch of resources to meet demand requirements AURORAxmp:

- Solves the whole system dispatch simultaneously.
- Dispatches hourly (with sampling capabilities, where appropriate).
- Determines the market-clearing prices from marginal costs.
- Values all the resources in the system.
- Provides price and value forecasts for each time period being studied.

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Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 24

Witness: David S. Sinclair

Q-24. Refer to the 2011 Resource Assessment at page 27 and Tables 20 and 21.

a. For high-sulfur coal price forecasts, explain whether Table 20 or Table 21 contains LG&E's and KU's contracted short-term positions. Also, explain why coal prices increase in Table 21.

b. Explain why natural gas prices appear to decrease in Table 21.

c. Explain why electricity prices increase in Table 21.

d. For Table 21 and in the discussion relating to that table, LG&E and KU state "[t]he electricity prices for 2011 Wood Mac/PIRA and 2011 CERA forecasts were developed in Aurora." Explain how those companies use the electricity forecasts developed by LG&E in its Aurora model.

A-24.

a. The coal price forecasts presented in Table 20 include the Companies' contracted positions through 2014 as of July 19, 2010. The 2011 Wood Mac/PIRA coal price forecast in Table 21 included the Companies' contracted positions through 2015 as of July 7, 2011. The 2011 CERA coal price forecast does not include the Companies' contracted positions.

The coal prices in Table 21 are higher than those in Table 20 due to the timing of the forecasts. Table 20 shows a coal price forecast that was developed in 2010. Table 21 shows coal price forecasts that were developed in 2011. The 2011 forecasts reflect higher market prices for coal.

b. In the 2011 Resource Assessment, the Companies inadvertently copied the wrong natural gas prices into Table 20 on page 26. In the new confidential version of the document, the 2011 Wood Mac/PIRA natural gas prices in Table 21 are the same as the natural gas prices in Tables 20 beyond 2014. Prior to 2015, the differences between these gas forecasts are explained by the fact that the market forward gas prices are not factored into the shorter-term portion of the natural gas prices in Table 20.

c. The electricity prices in Tables 20 and 21 are a based on the underlying coal and gas prices, which are inputs to the Companies' electricity pricing model (Aurora). The higher electricity prices in Table 21 compared to Table 20 result from the higher coal prices in Table 21.

d. The electricity price forecasts displayed in Tables 20 and 21 were developed by the Companies in the Aurora model based on the corresponding coal and gas price forecasts shown in these tables. Wood Mackenzie, PIRA, and CERA do not use the electricity prices developed by the Companies in any way.

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Response to the Commission Staff's First Information Request
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Case No. 2011-00375

Question No. 25

Witness: David S. Sinclair

Q-25. Refer to the 2011 Resource Assessment at page 28.

a. What is the relationship between Table 22 and Table 21? Was the data in Table 21 used in the evaluation of the final Phase II analysis?

b. The natural gas price forecasts that appear in Tables 21 and 22 appear to be significantly lower that the natural gas price forecasts provided by LG&E and KU in Case Nos. 2011-00161 and 2011-00162 on September 1, 2011 as an update to a previous response in those cases. Provide an explanation of the apparent discrepancies.

A-25.

a. Tables 21 and 22 contain alternative price forecasts to the 'base case' forecasts in Table 20. In the updated final Phase II analysis, the alternatives evaluated in the final Phase II analysis were evaluated using the 'base case' commodity prices as well as the '2011 Wood Mac/PIRA' and '2011 CERA' commodity prices. The latter two sets of commodity prices were selected because the average margin between gas and coal prices is largest in the 2011 Wood Mac/PIRA forecasts and smallest in the 2011 CERA forecasts.

b. In response to the Commission Staff's Second Request for Information Question No. 32(b and d) (KU) and Question No. 23(b and d) (LG&E) (Case Nos. 2011-00161 and 2011-00162) filed on September 1, 2011, the Companies provided coal and gas prices that included delivery costs to the Companies' generating stations. Tables 21 and 22 of the 2011 Resource Assessment display Henry Hub gas price forecasts which do not include delivery costs and are therefore lower.

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Response to the Commission Staff's First Information Request
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Case No. 2011-00375

Question No. 26

Witness: Gary H. Revlett

Q-26. Refer to page 31 of the 2011 Resource Assessment. It states, "[b]y utilizing the emissions from the existing Cane Run 4-6 to be shut down, the new CCCT was able to 'net out' of the Prevention of Significant Deterioration permitting requirements."

a. Provide the allocated emissions allowance for the proposed new CCCT beginning in 2016 and beyond and explain how it was determined.

b. Explain whether LG&E and KU will receive more SO_2 and NO_x allowances for the new CCCT unit because it is located on an existing generation site.

A-26. The following answers are based on EPA's Federal Implementation Plan ("FIP") which is currently in effect for implementing the Cross-State Air Pollution Rule ("CSAPR"), also known as the Transport Rule. If Kentucky elects to develop its own regulations to implement the CSAPR program, and the EPA approves the State Implementation Plan ("SIP"), the allocation mechanisms could be changed.

a. New units are allocated allowances equal to their previous years' emissions. For their first year of operation, they are allocated allowances equal to that year's emissions. These allowances come from a separate state-specific pool of allowances called the new-unit set-aside. If there are insufficient allowances in the new-unit set-aside to accommodate all new units, each unit will receive a pro-rated share of available allowances. Based on announced plans for new units in Kentucky, it is likely that the new unit set-aside pool will have sufficient allowances for the foreseeable future. The table below provides the expected allocated allowances beginning in 2016 based on the above described assumptions and our predicted NGCC utilization. The table below is also based on meeting native load requirements without significant purchase of power.

Projected Allowance Allocations for Cane Run NGCC*			
Year	**Annual NO_x (tons)**	**Ozone NO_x (tons)**	**SO_2 (tons)**
2016	64	28	3
2017	64	28	3
2018	64	29	3
2019	77	35	4
2020	82	36	4
2021	52	19	3
2022	39	20	3
2023	44	21	2
2024	43	21	3
2025	46	22	3

*-Based on meeting native load requirements without significant outside power purchases.

b. All new units are allocated allowances on a specific unit by unit basis, as described above, regardless of their location, whereas the applicability of Prevention of Significant Deterioration permitting is a source-wide or plant-wide evaluation.

The CSAPR allocations are unit-by-unit under the FIP, however the allowance accounts are per station or plant. Thus, the Cane Run account will continue to receive allocations associated with the coal-fired units for four years following their shutdown per the FIP. For example, if the coal-fired units are shut down in December 2015, they will continue to receive allocations for 2016-2019.

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Response to the Commission Staff's First Information Request
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Case No. 2011-00375

Question No. 27

Witness: David S. Sinclair

Q-27. Refer to the 2011 Resource Assessment, Appendix G, at page 44. For the top four options in the No Economy Sales category, the Production Costs and the Capital costs and the Gas Transmission costs for the 605 MW self-build option do not appear to be in line with the costs for the 640 MW and the 690 MW self-build options. Explain why the 605 MW option costs appear to be high relative to the 640 MW and 690 MW options.

A-27. Please see the response to Question No. 19(e).

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**Response to the Commission Staff's First Information Request
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Case No. 2011-00375

Question No. 28

Witness: Gary H. Revlett

Q-28. Refer to page 5 of the Direct Testimony of John N. Voyles, Jr. ("Voyles Testimony") where it is stated that the air quality in Jefferson County fails to meet SO_2 requirements and that the new Natural Gas Combined Cycle ("NGCC") plant will help meet the National Ambient Air Quality Standards ("NAAQS") for SO_2. With the retirement of the Cane Run coal-fired plants and the completion of the Cane Run NGCC facility:

a. Will Jefferson County meet the NAAQS standards?

b. If not, what, if any, further contributions are projected from LG&E?

c. Are there current or anticipated penalties ascribed to LG&E if Jefferson County fails to meet the NAAQS standards after the Cane Run NGCC has been completed?

A-28.

a. Whether Jefferson County meets the new 1-hour SO_2 NAAQS will be determined by the Kentucky Division for Air Quality ("KDAQ") with the assistance of the Louisville Metro Air Pollution Control District ("APCD"). This determination will be based on computer modeling of all SO_2 emitting sources which impact Jefferson County. Under EPA's implementation requirements for the new SO_2 NAAQS, KDAQ must complete this modeling and develop a revised State Implementation Plan ("SIP") plan for the non-attainment areas by February 2014. KDAQ is beginning to collect the information necessary to perform this required computer modeling, but they will likely not complete the analysis until late next year.

   Although the KDAQ and APCD will ultimately establish the future SO_2 emission limit for each source in Jefferson County, LG&E has performed its own evaluation of NAAQS compliance for the Cane Run and Mill Creek facilities to determine the need for SO_2 reductions. This analysis demonstrated the need for improved SO_2 controls at Mill Creek and significant SO_2 emission reductions at Cane Run.

   These two LG&E facilities currently represent approximately ninety percent of the SO_2 emissions in Jefferson County. However, with the Mill Creek flue-gas desulfurization ("FGD") improvements requested in the 2011 ECR filing and the proposed Cane Run NGCC requested in this filing, Jefferson County SO_2 emissions will be reduced by over 70 percent. Given these actions proposed by LG&E, Jefferson County should achieve attainment of the new 1-hour SO_2 NAAQS.

b. N/A

c. As mentioned in response to Question 28(a), compliance with the NAAQS will be based on computer modeling (not just ambient monitors) and these air quality impact models generally tend to over-predict the actual ambient air concentrations. Therefore, if the KDAQ modeling demonstrates that the Cane Run NGCC does not cause or contribute to a 1-hour SO_2 violation, then no further actions will be necessary. However, if the air quality impact modeling does not demonstrate attainment, then further SO_2 reductions will be required by those sources which are causing or significantly contributing to the non-attainment area.

Once KDAQ finalizes the air quality impact analysis demonstrating NAAQS compliance, new SO_2 allowable emissions rates will be established for these modeled sources. Like any other emission limits specified in the Kentucky's SIP, if a source violates this SIP limit, then the source is potentially subject to both state and EPA penalties.

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**Response to the Commission Staff's First Information Request
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Case No. 2011-00375

Question No. 29

Witness: John N. Voyles, Jr.

Q-29. Page 7 of the Voyles Testimony discusses bid and regulatory approval timelines. Explain whether LG&E and KU will have pre-qualified the majority of potential bidders prior to receiving regulatory approval.

A-29. Pre-qualification of major equipment and Engineering Procurement and Construction ("EPC") bidders will occur prior to receiving regulatory approvals. LG&E and KU, in concert with their Owner's Engineer, commenced pre-qualification processes for the major equipment (combustion turbines, steam turbines, and the heat recovery steam generator) and the EPC contractor in the third quarter of 2011. The pre-qualification processes, resulting in technically and financially vetted suppliers, will be complete prior to release of a Request for Quotation. A Request for Quotation will be released prior to receiving regulatory approvals such that bidding, evaluations and negotiations can progress to a point such that the Companies can issue critical path equipment purchase orders within 60 days of Commission approval, as described in previous testimony.

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Response to the Commission Staff's First Information Request
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Case No. 2011-00375

Question No. 30

Witness: David S. Sinclair

Q-30. Refer to pages 9 and 12 of the Voyles Testimony where the annual operating costs of CR7 and Bluegrass Generation are discussed. Explain how much weight the operating costs of the proposed facilities were given to arrive at the proposed ownership percentages. Provide all calculations and workpapers necessary to support the answer.

A-30. Cane Run 7's operating and maintenance costs were not included in its ownership calculation because the ownership allocation methodology was driven by the energy savings (based on fuel and environmental consumables) that would be derived by each company from energy generating from CR7. Because CTs are expected to generate relatively little energy (compared to NGCCs or coal units), the ownership allocation for the Bluegrass CTs was based on balancing the Companies' individual reserve margins and did not use any operating costs as an input. The workpapers with the ownership calculation are attached on the CD in the folder titled Question No. 30 and are being provided pursuant to a Petition for Confidential Protection.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 31

Witness: John N. Voyles, Jr.

Q-31. Page 11 of the Voyles Testimony includes discussion concerning the number of starts each Westinghouse generator has.

a. How many starts are these generators reliably expected to provide in their respective service lives?

b. Can it, and in the future will it, be feasible to rebuild the Bluegrass generators?

c. What is the maintenance cycle of the Westinghouse peaking units?

A-31.

a. Major combustion turbine components are typically designed for a nominal life of approximately 3,200 starts. This is not to say that the life of the asset will expire after 3,200 starts. These major internal components are designed to be replaced and/or upgraded to permit further operation of the unit for its full design life and the ability to reliably support start demands. Combustion turbine component replacements are addressed through the normal equipment maintenance schedules. Ongoing start reliability is a function of a well-executed equipment maintenance and parts replacement program.

b. During the life of the units, they will undergo normal equipment maintenance and overhauls in accordance with the manufacturer's recommendations. As such, parts and components required for ongoing operation of the units will continuously be replaced, as required. In this manner, the design life of the assets units will be achieved.

c. The manufacturer recommended maintenance cycle for these units will be based upon the quantity of starts since they are peaking units. This maintenance cycle requires a combustor inspection after 400 equivalent starts. This sequence then repeats. There are upgrade packages available to increase these inspection intervals and to extend the maintenance intervals of the units.

LOUISVILLE GAS AND ELECTRIC COMPANY
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KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 32

Witness: John N. Voyles, Jr.

Q-32. On page 13 of the Voyles Testimony, it is stated that the transmission interconnection study which LG&E and KU requested be performed by SPP is not complete. When will the final study results be available?

A-32. Cane Run is fifth in the Generation Interconnection queue to be studied per the Open Access Transmission Tariff ("OATT") by SPP. The Queue Position of each Interconnection Request is used to determine the order of performing the Interconnection Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request. A higher queued Interconnection Request is one that has been placed "earlier" in the queue in relation to another Interconnection Request that is lower queued.

Due to the OATT generation queue serial process and the current position of the Cane Run Generator interconnection request, a final study completion time cannot be determined at this time. Four higher queued Interconnection studies will need to be completed prior to the initiation of the interconnection study process of OATT.

LOUISVILLE GAS AND ELECTRIC COMPANY
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KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 33

Witness: John N. Voyles, Jr.

Q-33. Refer to page 14 of the Voyles Testimony. Explain whether LG&E and KU anticipate needing any further transmission approvals from the Commission.

A-33. At this time, LG&E and KU do not anticipate needing any further transmission approvals from the Commission related to this application.

LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request Dated October 26, 2011

Case No. 2011-00375

Question No. 34

Witness: Lonnie E. Bellar / Dan Arbough

Q-34. Refer to page 3 of the Direct Testimony of Lonnie E. Bellar ("Bellar Testimony") where he states that some portion of the financing costs for both proposed projects could be loans from affiliates via the money pool. Explain the structure and operation of the money pool arrangement. Include a description of the means by which interest rates are set for money pool transactions.

A-34. The money pool arrangement is a mechanism that allows LG&E and KU to borrow or lend available funds at competitive rates and avoid paying fees to financial intermediaries. There is a borrowing limit of $400 million for each Company within the money pool although, as described below, an application has been filed to increase the limit to $500 million. LG&E and KU Energy LLC ("LKE") is an authorized lender in the money pool as are both LG&E and KU. LG&E and KU are the only authorized borrowers in the money pool. LG&E and KU Services ("Servco") administers the money pool at no cost, but is not a borrower or a lender. If one of the three authorized lenders has available cash, it may offer to lend the funds to one of the authorized borrowers in the money pool. Given the rate structure described below, the interest rate charged to a borrower is very competitive with other borrowing alternatives as is the rate a lender will earn compared to other investment alternatives. The rates are competitive for both parties because there is no intermediary earning a profit on each portion of the transaction. The loans are due on demand from the lender.

The interest rate for money pool debt is currently equal to the rate for high-grade unsecured 30-day commercial paper of major corporations sold through dealers as quoted in The Wall Street Journal (the "Average Composite") on the last business day of the prior calendar month. However, this rate no longer approximates the market rates for companies with a credit rating similar to the Companies. The Average Composite is based on issuers with short-term debt ratings of A-1/P-1 while the Companies are now rated A-2/P-2. Consequently, an application has been filed with the Virginia State Corporation Commission ("VSCC") to change the method for determining the money pool interest rate. Under the proposed change, the rate would be set monthly at the rate for A2/P2/F2 rated US Commercial Paper programs as quoted by Bloomberg under the ticker DCPD030D on the last business day of the prior calendar month. As noted above, in the same application to the VSCC, the Companies have requested that the borrowing limit be increased to $500 million for each of LG&E and KU.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 35

Witness: Lonnie E. Bellar

Q-35. Refer to page 6 of the Bellar Testimony where he discusses the rate impacts of the proposed construction and acquisition.

a. The expected rate impact for KU is 4 percent. Explain whether the timing of KU's need for a rate case will be affected by KU's proposal to acquire generation in this case.

b. Mr. Bellar states LG&E's share of its ownership in the CR7 and Bluegrass Generation will have little impact on LG&E base rates. LG&E's share of the ownership will exceed an estimated $200 million. Explain why this expenditure is not expected to affect rates.

A-35.

a. KU has not made a determination as to when it will file an Application seeking an adjustment to its electric base rates. Such a determination will be based on the overall financial results of the Company. While KU consistently seeks to provide reliable service in a least cost, reasonable manner, increases in operating expenses and capital expenditures could cause the utility to file a base rate case upon, or prior to, placing the generating units in service.

b. The statement referenced relates to total rates, inclusive of fuel, not just base rates. LG&E has not make a determination as to when it will file an Application seeking an adjustment to its electric base rates. Such a determination will be based on the overall financial results of the Company. While LG&E consistently seeks to provide reliable service in a least cost, reasonable manner, increases in operating expenses and capital expenditures could cause the utility to file a base rate case upon, or prior to, placing the generation units in service.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 36

Witness: Lonnie E. Bellar / Shannon Charnas

Q-36. Refer to page 6 of the Bellar Testimony where Mr. Bellar discusses the plan to perform a depreciation study based on December 31, 2011 data.

a. Explain whether LG&E and KU plan to use a December 31, 2015 retirement date in the study for the generating units.

b. Provide the retirement date used for these six generating units in the most recent LG&E/KU depreciation study.

c. Provide LG&E's and KU's current position on how the net book value of the generating units that have been proposed to be retired will be addressed in the first rate cases following the retirement dates.

d. Provide the following information for the generating units that are planned to be retired in 2015, as of September 30, 2011:

Unit Name	Installed Cost (Col. 1)	Accumulated Depreciation (Col. 2)	Net Book Value (Col. 1 – Col. 2) (Col. 3)
Cane Run 4			
Cane Run 5			
Cane Run 6			
Green River 3			
Green River 4			
Tyrone 3			
Total			

A-36.

a. The current plan is to use a December 31, 2015 or earlier retirement date for the three units at Cane Run, two units at Green River and the one unit at Tyrone in performing the depreciation study as of December 31, 2011. Collection of the data for the study is underway. The study will not be completed until 2012.

b. The retirement dates used in the 2006 Depreciation Study for these units are as follows:

Unit	Probable Retirement Date
Cane Run 4	2018
Cane Run 5	2022
Cane Run 6	2023
Green River 3	2018
Green River 4	2018
Tyrone 3	2018

c. LG&E's and KU's current position on how the net book value of the generating units that have been proposed to be retired will be addressed in the first rate cases following the retirement dates has not been determined. LG&E and KU expect to complete a depreciation study next year based on information from the year ending December 31, 2011. Collection of the data is not complete at this time and the study will not be complete until mid 2012. The depreciation study will be presented in LG&E's and KU's next base rate case.

d. As of September 30, 2011, LG&E and KU recorded the installed cost and allocated related accumulated depreciation to each facility as set forth in the table below.

Note: The Accumulated Depreciation amounts in column 2 below do not include the cost of removal and salvage components segregated previously in past studies.

Unit Name	Installed Cost (Col. 1)	Accumulated Depreciation (Col. 2)	Net Book Value (Col. 1 – Col. 2) (Col. 3)
Cane Run 4	$ 69,521,893	$ 57,911,569	$ 11,610,324
Cane Run 5	96,542,244	66,398,605	30,143,639
Cane Run 6	171,615,343	109,607,011	62,008,332
Green River 3	20,909,570	14,893,190	6,016,380
Green River 4	49,037,764	33,895,554	15,142,210
Tyrone 3	28,318,638	19,304,590	9,014,048
Total	$ 435,945,452	$ 302,010,519	$ 133,934,933

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 37

Witness: David S. Sinclair

Q-37. On page 6 of his testimony, Mr. Bellar states that, when rate impact estimates were provided in connection with the environmental recovery press release, the estimates were based upon the assumption that LG&E would own 100 percent of CR7 and KU would own 100 percent of the Bluegrass Generation assets. However, upon further study, LG&E and KU determined that the joint ownership now proposed is the most appropriate.

a. Provide the major factors influencing the decision to share ownership in the units.

b. Explain whether the likelihood of either utility relying upon the new generation for base load needs, rather than intermediate or peak load needs, influenced the decision on joint ownership in any way.

A-37.

a. The major factors leading the Companies to recommend sharing ownership of the proposed new units are each Company's load profiles and their levels of existing baseload capacity available to meet their individual energy needs. Figure 2 in the 2011 Resource Assessment demonstrates that KU has a greater summer energy need compared to LG&E, with KU forecasted to have more hours in the summer of 2016 in which its load is greater than its baseload capacity.[2] KU is also forecasted to have a significant winter energy need in 2016 while LG&E is not, as demonstrated in Figure 3 of the 2011 Resource Assessment.[3] KU's greater forecasted need for baseload energy warranted a more equitable ownership split of the proposed Cane Run Unit 7 compared to the original assumption for 100% LG&E ownership. As mentioned in the 2011 Resource Assessment, the ownership of the Bluegrass CTs

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[2] *See* Sinclair Testimony Exhibit DSS-1, *2011 Resource Assessment*, September 2011, page 34.
[3] *Id.* at 34-35.

was calculated to balance the Companies' reserve margins, given the calculated ownership split of Cane Run 7.[4]

b. As discussed in the response to Question No. 30, the ownership calculation was based on balancing the Companies' individual energy benefits that would result from adding the proposed Cane Run Unit 7. As mentioned in the response to Question No. 37(a), a primary driver of the ownership decision is each Company's load characteristics compared to its baseload capacity. These factors impact each Company's reliance on the new capacity for energy and thereby each Company's expected energy benefits resulting from the new capacity.

[4] *Id.* at 35.

LOUISVILLE GAS AND ELECTRIC COMPANY
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KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 38

Witness: Gary H. Revlett

Q-38. Refer to the Direct Testimony of Gary H. Revlett ("Revlett Testimony") at page 11. Will the construction of the facilities described in the application permit the Jefferson County non-attainment designation to be lifted?

A-38. Please see response to Question No. 28(a).

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated October 26, 2011

Case No. 2011-00375

Question No. 39

Witness: Gary H. Revlett

Q-39. Refer to the Revlett Testimony at page 13. Will there be any anticipated issues in transferring control of the permits associated with the Bluegrass Station?

A-39. No. The Companies foresee no issues or concerns with transferring control of the permits to our companies. It is anticipated the Bluegrass Station will receive their new Kentucky Pollutant Discharge Elimination System ("KPDES") permit prior to the transfer of ownership. Once the transfer occurs the Kentucky Division of Water will be informed of the ownership change, but the KPDES permit will remain in effect for the facility with no changes.

Likewise, within 10-days following the ownership transfer, the Companies will submit a revised Form DEP7007AI to the Kentucky Division for Air Quality to identify the change in ownership and operational control. This change is considered a simple administrative change under 401 KAR 52:020 Section 13.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATE FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION TURBINE AT THE CANE RUN GENERATING STATION AND THE PURCHASE OF EXISTING SIMPLE CYCLE COMBUSTION TURBINE FACILITIES FROM BLUEGRASS GENERATION COMPANY, LLC IN BUCKNER, KENTUCKY	)	**CASE NO. 2011-00375**

JOINT APPLICANTS' PETITION FOR CONFIDENTIAL PROTECTION AND FOR DEVIATION FROM FILING REQUIREMENTS

Joint Applicants, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (together, the "Companies"), hereby petition the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001, Section 7, and KRS 61.878(1)(c) to grant confidential protection for documents attached to the Commission Staff's First Information Request and for permission to file some of the responsive information on compact disc rather than in hard copy. In support of this Petition, the Companies state as follows:

1. The Kentucky Open Records Act exempts from disclosure certain commercial information. KRS 61.878(1)(c). To qualify for the exemption and, therefore, maintain the confidentiality of the information, a party must establish that the material is of a kind generally recognized to be confidential or proprietary, and the disclosure of which would permit an unfair commercial advantage to competitors of the party seeking confidentiality.

2. In support of their Joint Application in this matter, the Companies submitted the Direct Testimony of David S. Sinclair. The Companies' Resource Assessment was attached as an exhibit to Mr. Sinclair's testimony. The Resource Assessment is a comprehensive document that describes the process by which the Companies determined the least-cost solution for meeting their electric generation needs and contains confidential information. Therefore, when the Companies filed it, they sought confidential protection via a September 15, 2011 Petition for Confidential Protection. That petition is still pending.

3. Recently, the Companies realized that there were some errors in the Resource Assessment. Therefore, as explained in their November 9, 2011 responses to the Commission Staff's First Information Request Item 17(b), they are providing a corrected version of the Resource Assessment which is attached. For all the reasons set forth in their pending September 15, 2011 Petition for Confidential Treatment, the Companies likewise seek confidential protection of the corrected version of the Resource Assessment.

4. Both the confidential version of the corrected Resource Assessment and the Companies' November 9, 2011 responses to Items 8(d), 19(b) and 22(b) of the Commission Staff's First Information Request contain information the Companies obtained from vendors concerning projected fuel prices. At the time of filing, those vendors would not allow the Companies to reveal their proprietary information confidentially or otherwise. Therefore, it was redacted from the Resource Assessment. Since then, the Companies have obtained permission to disclose that projected fuel price information confidentially. If the Commission grants public access to this information, the vendors from whom the Companies purchased the fuel price forecast information at issue could refuse to do business with the utilities in the future. Such a result would do serious harm to the Companies' ability to make prudent fuel contract and other

decisions. All such commercial damage would ultimately harm the Companies' customers. Moreover, publicly disclosing such information would do immediate and costly harm to the vendors from which the Companies purchased the fuel forecast information at issue; the firms derive significant revenues from developing and selling such forecasts to customers under strict license agreement obligations not to disclose. Any public disclosure of the forecasts would render them commercially worthless. Thus, the Companies seek confidential protection of this information.

5. The Companies' response to Item 17(a) contains a summary of the responses the Companies received after they issued the Request for Proposal that is described in the Resource Assessment. As set forth in the Companies' pending September 15, 2011 Petition for Confidential Treatment, this is commercially sensitive information and is confidential. Thus, for the reasons explained in the pending September 15, 2011 Petition for Confidential Treatment, the Companies request protection.

6. The Companies' response to Item 30 includes an attachment (it is being provided on a compact disc in accordance with the request in Paragraph 10 below) that shows the Companies' expected fuel costs. The Companies seek to protect expected fuel cost information from public disclosure. This information was developed internally by the Companies' personnel, is not on file with any public agency, is not available from any commercial or other source outside the Companies, and is distributed within the Companies only to those employees who must have access for business reasons. If publicly disclosed, this information, which is used to determine the Companies' margins for the sale of bulk power loads, could give the Companies' competitors an advantage in bidding for and securing new bulk power loads. Similarly, disclosure would afford an undue advantage to the companies' wholesale power purchasers, as

the latter would enjoy an obvious advantage in any contractual negotiations to the extent they could calculate the Companies' costs and sales margins.

7. If the Commission disagrees with any of these requests for confidential protection, however, it must hold an evidentiary hearing (a) to protect KU's due process rights and (b) to supply with the Commission with a complete record to enable it to reach a decision with regard to this matter. Utility Regulatory Commission v. Kentucky Water Service Company, Inc., 642 S.W.2d 591, 592-94 (Ky. App. 1982).

8. The Companies will disclose the confidential information pursuant to a confidentiality agreement, to intervenors and others with a legitimate interest in this information and as required by the Commission.

9. 807 KAR 5:001, Section 7(2) requires the Companies to file one copy of the material which identifies by highlighting the information for which confidential protection is sought and ten copies of the material with the confidential information obscured. Those copies are attached.

10. Finally, the attachments to the responses to Items 22(b) and 30 of the Commission Staff's First Request for Information are voluminous and mostly unintelligible in hard copy format because they are intended to be read on a computer. Therefore, the Companies request permission pursuant to 807 KAR 5:001 § 14 to deviate from the requirement to file an original and ten copies of these documents and, instead, request permission to submit and serve this information on compact disc.

WHEREFORE, the Companies respectfully request that the Commission grant confidential protection for the information at issue, or in the alternative, schedule an evidentiary hearing on all factual issues while maintaining the confidentiality of the information pending the outcome of the hearing. The Companies further request approval to deviate from the standard filing requirements and submit the above-described information on compact disc.

Dated: November 9, 2011

Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing pleading has been served by mailing a copy of same, postage prepaid, to the following persons on the 9th day of November, 2011:

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