Steven L. Beshear
Governor

Leonard K. Peters
Secretary
Energy and Environment Cabinet

David L. Armstrong
Chairman

James W. Gardner
Vice Chairman

Linda Breathitt
Commissioner

Commonwealth of Kentucky
Public Service Commission
211 Sower Blvd.
P.O. Box 615
Frankfort, Kentucky 40602-0615
Telephone: (502) 564-3940
Fax: (502) 564-3460
psc.ky.gov

October 14, 2014

PARTIES OF RECORD

RE: Case No. 2014-00321

Application of Louisville Gas and Electric Company and Kentucky Utilities Company For a Declaratory Order and Approval Pursuant to KRS 278.300 for a Capacity Purchase and Tolling Agreement

Enclosed please find a memorandum that has been filed in the record of the above referenced case. Comments regarding this memorandum's content should be submitted to the Commission within five days of the receipt of this letter. Questions regarding this memorandum should be directed to Jeff Shaw of the Commission Staff at 502-782-2660.

Jeff Derouen
Executive Director

Enclosures

INTRA-AGENCY MEMORANDUM

KENTUCKY PUBLIC SERVICE COMMISSION

TO: Case File

FROM: Jeff Shaw JS

DATE: October 14, 2014

RE: Case No. 2014-00321
Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Declaratory Order and Approval Pursuant to KRS 278.300 of a Capacity Purchase and Tolling Agreement

Pursuant to a motion filed by Louisville Gas and Electric Company and Kentucky Utilities Company ("the Companies"), an informal conference ("IC") scheduled by order of the Commission dated October 1, 2014 was held at the Commission's offices on October 10, 2014. A list of the IC attendees is included as Attachment 1 to this memo.

The Companies' representatives made a presentation of their short-term capacity needs and the capacity purchase agreement the Companies have entered into with Bluegrass Generation Company, LLC. To assist in the presentation, the Companies distributed two confidential handouts at the IC. The first handout was titled Overview of Short-term Capacity Need and Bluegrass Generation Agreement while the second was titled Analysis of May 2014 RFP Responses.[1] Redacted versions of the handouts are included as Attachments 2 and 3 to this memo.

Commission Staff ("Staff") distributed a handout of questions to be treated as an IC Request for Information to the Companies. Staff also inquired as to the latest date for a final order that would permit the Companies to go forward with steps necessary to implement the capacity purchase agreement. A copy of the IC Request for Information is included as Attachment 4 to this memo. Lead counsel for the Companies e-mailed the Commission's General Counsel later on the day of the IC to indicate that November 26, 2014 was the last date the Companies believed reasonable for a final order. The e-mail also indicated the Companies would submit responses to the IC Request for Information by October 17, 2014. A copy of the e-mail is included as Attachment 5 to this memo.

Staff reminded the IC attendees that this memorandum would be filed in the record of this case and distributed to the parties. There being no further discussion at that point, the IC was adjourned.

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[1] The Analysis of May 2014 RFP Responses had been previously submitted as Exhibit 6 to the Companies' September 19, 2014 application.

Case No. 2014-00321 IC Memorandum

Attachment 1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A DECLARATORY ORDER AND APPROVAL PURSUANT TO KRS 278.300 FOR A CAPACITY PURCHASE AND TOLLING AGREEMENT	)	CASE NO. 2014-00321

October 10, 2014

Please sign in:

NAME	REPRESENTING
Jonathan Beyer	PSC
Robert Conroy	LG&E/KU
[illegible]	SKO for LG&E/KU
JEFF SHAW	PSC - FIN. ANALYSIS
Leah Faulkner	PSC-FA
David Sinclair	LG&E-KU
Stuart Wilson	LG&E/KU
Bob Bruner	LG&E/KU
Allyson Sturgeon	LG&E & KU
RICK LOVEKAMP	LG&E/KU
RICHARD RAFF	PSC-LEGAL
Kurt Boehm	KIUC
Chris Whelan	PSC-FA

Feraydoon Gorjian

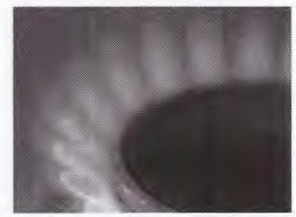
PSC

Case No. 2014-00321 IC Memorandum

Attachment 2

REDACTED



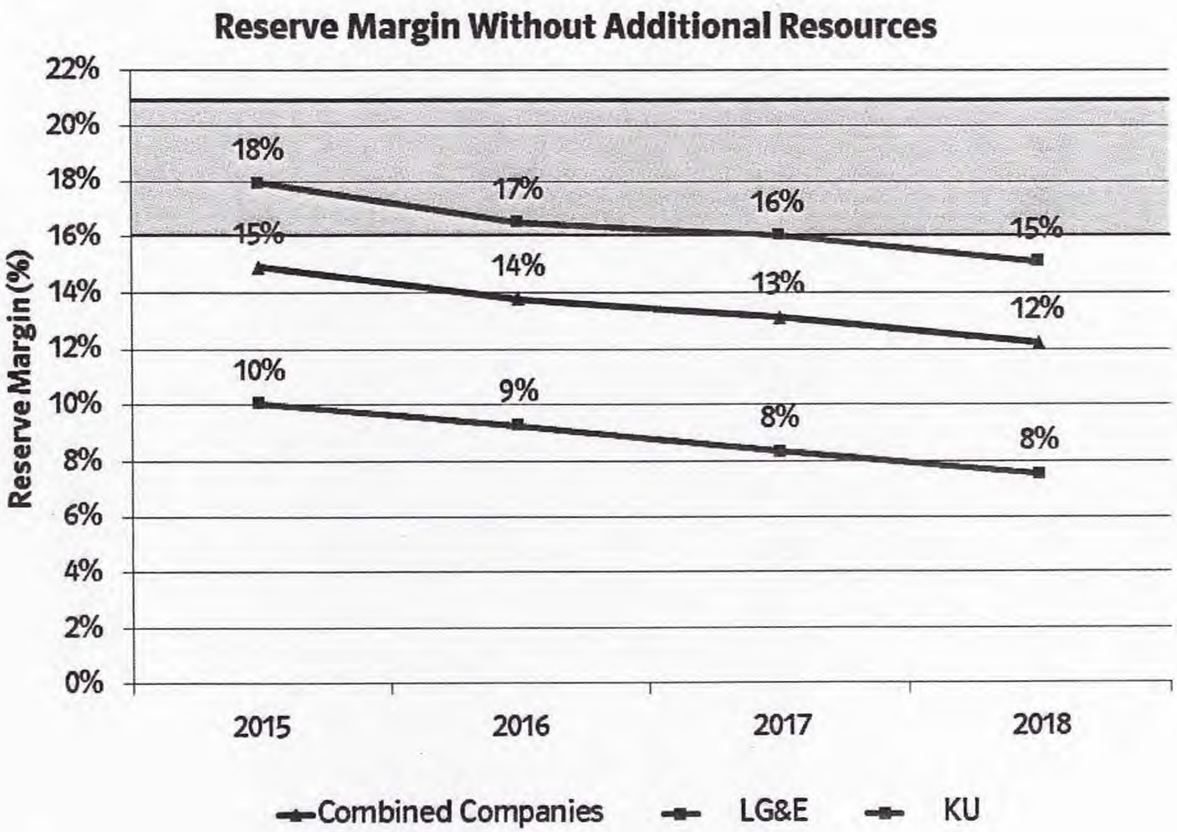
LG&E KU

PPL companies

Overview of Short-term Capacity Need and Bluegrass Generation Agreement

Case No. 2014-00321
Informal Conference
October 10, 2014

Reserve margin without additional resources forecasted to be below minimum of target range in 2015-2018



Source: 2014 IRP, excluding Green River NGCC

Issued RFP in May 2014 to 14 parties

- *RFP was issued to OVEC owners and September 2012 RFP respondents with existing assets capable of meeting 2015-2018 reserve margin need to maintain system reliability.*

Companies Receiving RFP

[redacted]

Respondents	(Balancing Area)
[redacted]	[redacted]

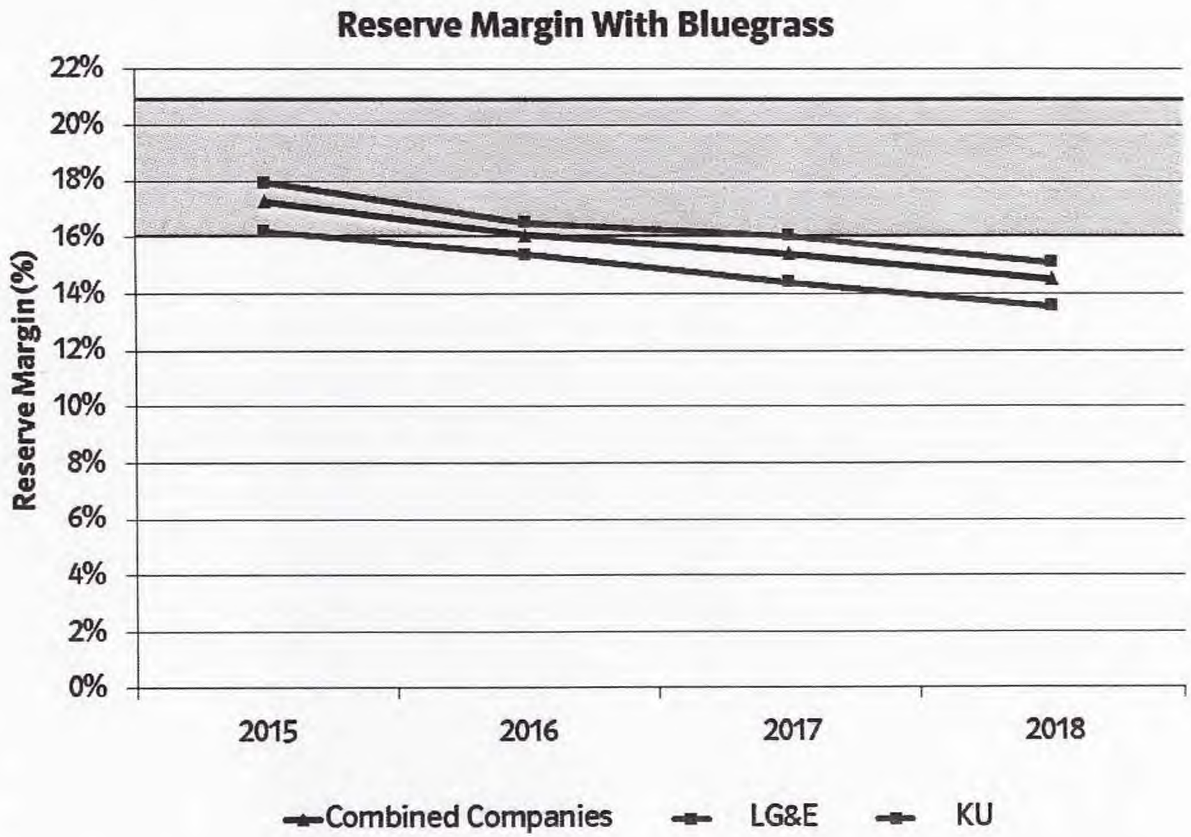
Contract with LS Power's Bluegrass Generation is the least-cost alternative

- [redacted] *proposal was eliminated due to non-firm nature of proposal.*
- [redacted], [redacted], *and* [redacted] *proposals were eliminated due to lack of electric transmission transfer capability.*
- [redacted] *proposal was lower cost than* [redacted] *proposal due primarily to transmission cost advantages associated with* [redacted] *balancing area.*

Highlights of Bluegrass Capacity Purchase and Tolling Agreement

- *Volume and Term*
  - *165 MW*
  - *May 2015 through April 2019*
  - *Energy scheduled with 2-hour notice*
- *Tolling Agreement*
  - *LG&E/KU delivers natural gas to site*
- *Contract Contingencies*
  - *KPSC approval*
  - *Securing electric transmission service (LG&E/KU balancing area)*
  - *Securing firm gas transportation service (Texas Gas Transmission)*
- *Financial Terms*
  - *Capacity price* — *$4.15/ kW-month (fixed)*
  - *Fixed O&M charge* — *$0.70/kW-month (escalates 2.5%)*
  - *Variable O&M charge* — *$0.55/MWh (escalates 2.5%)*
  - *Startup Charge* — *$8,500/start (escalates 2.5%)*
- *Performance Guarantees*
  - *Guaranteed heat rate (10,900 btu/kWh)*
  - *Availability incentive (prorated credit for hours not available when scheduled)*
  - *Letter of Credit and Parent Guarantee*

Bluegrass allocated 100% to LG&E to better align reserve margins between companies



Source: 2014 IRP, excluding Green River NGCC, including Bluegrass

Fuel Adjustment Clause Recovery

- *Capacity Purchase and Tolling Agreement characteristics*
  - *Considered to be an Operating Lease from accounting standpoint*
  - *Designated Unit No. 3 as a network resource*
  - *LG&E-KU will dispatch unit as if they owned the unit*
- *Charge the fuel and transportation costs used to operate the Unit to FERC Account No. 547, Fuel, and then book all costs to FERC Account No. 151, Fuel Stock.*
- *Monthly Fuel Adjustment terms provide a credit from Seller to the Buyer should the unit fail to achieve the guaranteed heat rate. Credit reflected in Account 151 and flowed back through Account 547, Other Production Fuel Expense, in the calculation of the monthly fuel adjustment clause factor.*
- *Fuel costs incurred are fuel costs for purposes of fuel adjustment clause recovery under 807 KAR 5:056(1)*
  - *(3)(a)("Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants") or:*
  - *(3)(b)("The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) of this subsection")*

LG&E KU
PPL companies

Current activities

- *Awaiting approval of request for 165 MW of Network Integration Transmission Service for Bluegrass Unit #3*
  - *Taking steps to make Energy Management System ("EMS") information on Bluegrass Unit #3 available to Generation Dispatch*
- *Discussing firm gas transport agreement with Texas Gas Transmission ("TGT")*
  - *Working with Bluegrass Generation and TGT on gas metering and telemetry*
- *LG&E and KU are required to make a change in status filing with FERC within 30 days after power flow under the contract commences*
- *Request Commission issue an order by November 18, 2014*

Case No. 2014-00321 IC Memorandum

Attachment 3

REDACTED

Analysis of May 2014 RFP Responses

LG&E KU

PPL companies

Generation Planning & Analysis
August 2014

Table of Contents

1 Capacity and Energy Need

The Companies presented their most recently updated peak demand and energy forecast ("2014 LF") in the 2014 Integrated Resource Plan ("IRP") filed in April 2014. After the IRP was filed, on April 21, 2014, nine KU municipal customers provided notices of termination of their wholesale power agreements. As a result, KU's forecasted summer peak demand will be reduced by approximately 325 MW after April 30, 2019.[1] As a result of the municipal contract termination, on August 12, 2014, the Companies informed the Kentucky Public Service Commission ("KPSC") that they would be withdrawing their application for a Certificate of Public Convenience and Necessity ("CPCN") for a 2x1 natural gas combined cycle ("NGCC") generating facility at the existing Green River station that would have been operational by the summer of 2018. At the same time, the Companies informed the KPSC that they continued to recommend the approval of a 10 MW photovoltaic solar facility to be constructed at the E.W. Brown station by December 2016.

In preparing the 2014 IRP, it was assumed that both the Green River NGCC and Brown Solar Facility would be approved and constructed. With the pending reduction in load caused by the municipal contract termination, the withdrawal of the Green River NGCC CPCN, and the approval of the Brown Solar Facility still uncertain, the Companies have re-evaluated their capacity and energy needs through 2019. Table 1 shows the forecasted reserve margin from the 2014 IRP adjusted for the terminating municipal load and removal of the Green River NGCC and Brown Solar Facility. As discussed in the 2014 IRP, the Company's target reserve margin range is 16 percent to 21 percent. Compared to the minimum of this range, the Companies have a reserve margin shortfall from 2015 to 2018 but will be slightly above the minimum value once the municipals terminate.

Table 1 – LG&E/KU Resource Summary (MW, Summer, 2014 LF with Muni Termination)

	2015	2016	2017	2018	2019
Forecasted Peak Load	7,364	7,450	7,536	7,623	7,663
Energy Efficiency/DSM	(336)	(365)	(394)	(423)	(406)
Terminating Municipals	0	0	(16)	(16)	(325)
Net Peak Load	7,028	7,085	7,126	7,183	6,932
Existing Resources	7,792	7,775	7,775	7,775	7,775
Firm Purchases (OVEC)	155	155	155	155	155
Curtailable Demands	131	131	131	131	131
Total Supply	8,078	8,061	8,061	8,061	8,061
Reserve Margin ("RM")	14.9%	13.8%	13.1%	12.2%	16.3%
RM Shortfall (21%)	(427)	(512)	(562)	(631)	(326)
RM Shortfall (16%)	(75)	(157)	(205)	(272)	20

*Negative values reflect reserve margin shortfalls.

[1] The wholesale power contract with the City of Paris provided for a 3-year termination notice so their contract will terminate on April 30, 2017. The summer peak load of the City of Paris is forecasted to be 16 MW.

2 May 2014 RFP

To evaluate alternatives for meeting the Companies' capacity needs in 2015 through 2018, on May 14, 2014 the Companies issued an RFP for 100-350 MW of capacity and energy for the period of 2015 through 2020. The RFP responses are summarized in Table 2.

Table 2 – Summary of May 2014 RFP Responses

	Respondent	PPA Proposal
1	[redacted]	[redacted]
2	[redacted]	[redacted]
3	[redacted]	[redacted]
4	[redacted]	[redacted]
5	[redacted]	[redacted]
6	[redacted]	[redacted]

3 RFP Analysis

The RFP analysis was completed in two parts. A screening analysis grouped similar proposals and identified the proposals in each group with the lowest levelized cost. As part of the screening analysis, the Companies assessed the availability of transmission capacity for each proposal. The least-cost proposals in each group with available transmission capacity were then evaluated in a detailed production cost analysis in the context of the Companies' generation portfolio.

3.1 Screening Analysis

For proposals with similar dispatch characteristics and contract terms, those with the lowest levelized cost will evaluate most favorably. For this reason, in the screening analysis, similar proposals were grouped together and evaluated against each other. To identify the proposals in each group with the lowest levelized cost per MWh, the proposals were evaluated under three operating scenarios and three gas price scenarios (nine scenarios in total). Operating scenarios were defined by an assumed capacity factor and number of starts per year. The operating scenarios evaluated for each group are summarized in Table 3.[2] The natural gas price scenarios were taken from the Companies' 2014 IRP and are summarized in Table 4. Each scenario in the screening analysis was assumed to be equally likely.

[2] The proposals from [redacted] for [redacted] have 16-hour and 2-hour minimum run-times, respectively. Since the screening analysis does not differentiate between these dispatch characteristics, the [redacted] proposals were grouped separately.

Table 3 – Operating Scenarios for Screening Analysis

	Scenario 1		Scenario 2		Scenario 3	
Group	**Capacity Factor**	**Number of Starts**	**Capacity Factor**	**Number of Starts**	**Capacity Factor**	**Number of Starts**
Coal	35%	20	50%	10	85%	5
NGCC	35%	20	50%	10	85%	5
Peak – 16 Hour Min Run-Time ("Peak_16hr")	2%	10	10%	50	20%	100
Peak – 2 Hour Min Run-Time ("Peak_2hr")	1%	10	5%	50	10%	100

Table 4 – Natural Gas and Coal Prices (Nominal $/mmBtu)

	Henry Hub Natural Gas Prices (Source: EIA)		
Year	**Low**	**Mid**	**High**
2015	2.52	3.32	3.85
2016	2.84	3.86	4.56
2017	2.85	4.06	4.96
2018	2.97	4.42	5.45
2019	3.03	4.59	5.86

The [redacted] proposal was not considered in the screening analysis. [redacted] proposed to [redacted] Since the Companies would not [redacted], the proposal from [redacted] was not considered a viable option.

The screening analysis considered each proposal's fixed and operating costs. Where applicable, the following costs were considered in the screening analysis:

1. Fuel/Energy Costs
2. Start Costs
3. Hourly Operating Cost
4. Variable O&M
5. Fixed O&M
6. Capacity Charge
7. Fixed Cost for Firm Transmission Service
8. Firm Gas Transportation Costs

The results of the screening analysis are summarized in Table 5. Based solely on price, the proposals from [redacted] were the top proposals in each group. However, as part of the screening analysis, the Companies assessed the availability of transmission capacity for each of these proposals. Based on this assessment, transmission capacity was not available from [redacted] over the contract term.[3] Therefore, the proposals from [redacted] were excluded from the subsequent detailed production cost analysis.

[3] A table listing the available transmission capacity from [redacted] is included in *Appendix A – Available Transmission Capacity*.

Table 5 – Screening Analysis Results

Group	Counterparty/Proposal	Levelized Fixed Cost ($/MWh)	Levelized Variable Cost ($/MWh)	Levelized Total Cost ($/MWh)
Coal	[redacted]	[redacted]	[redacted]	[redacted]
NGCC	[redacted]	[redacted]	[redacted]	[redacted]
NGCC	[redacted]	[redacted]	[redacted]	[redacted]
Peak_16hr	[redacted]	[redacted]	[redacted]	[redacted]
Peak_16hr	[redacted]	[redacted]	[redacted]	[redacted]
Peak_2hr	[redacted]	[redacted]	[redacted]	[redacted]

With no viable alternatives in the coal and NGCC screening groups, the top options in the remaining screening groups are the [redacted]. Therefore, these proposals were included in the more detailed production cost analysis.

3.2 Detailed Production Cost Analysis

The detailed production cost analysis covers the period May 1, 2015 through April 30, 2019. It uses inputs, including the load forecast and natural gas prices, from the 2014 IRP.

Table 6 lists the alternatives that were evaluated in the detailed production cost analysis. To improve the comparability of the analysis, the Companies evaluated the [redacted] proposals with capacities of [redacted] and [redacted]

Table 6 – Production Cost Analysis Alternatives

	Description	Delivered MW
1	[redacted]	[redacted]
2	[redacted]	[redacted]
3	[redacted]	[redacted]
4	[redacted]	[redacted]

As a result of the short-term nature of the Companies' energy and capacity need, the screening analysis demonstrated that the ranking of proposals is not materially impacted by the level of gas prices. Therefore, the detailed production cost analysis focused only on the Mid gas price scenario. The results of the detailed production cost analysis are summarized in Table 7.

Table 7 – Production Cost Analysis Results (PVRR 2015-2019, $2014, $M)

Description	Production Costs	Capacity Charge	Firm Gas Trans	Fixed O&M	Firm XM Costs	Total	Diff from Best
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Based on the results in Table 7, the [redacted] is the least-cost proposal, followed by [redacted]. According to the [redacted] proposal, the Companies must [redacted]. If the Companies do not do this, [redacted]

[redacted]. Given the structure of this proposal and the Company's obligation to maintain system reliability, the Companies would likely be forced during hot or cold weather periods to [redacted]. In doing this, the Companies would likely have to back down a less costly unit. This analysis does not consider this additional 'reliability' cost associated with the [redacted] proposal.

3.3 Final Recommendation

Based on the results of the detailed production cost analysis, the Companies entered into negotiations with [redacted] and ultimately signed a letter of intent for a [redacted]. Table 8 lists the results of the updated proposal alongside the results of the previously evaluated proposals. The [redacted] proposal is clearly the least-cost alternative for meeting the Companies short-term capacity and energy needs even without including the aforementioned 'reliability' cost in the [redacted] PVRR.

Table 8 – Updated Production Cost Analysis Results (PVRR 2015-2019, $2014, $M)

Description	Production Costs	Capacity Charge	Firm Gas Trans	Fixed O&M	Firm XM Costs	Total	Diff from Best
[redacted]							

The impact of this PPA on the Companies' forecasted reserve margin is summarized in Table 9. Based on Table 9, the reserve margin may fall below the low end of the 16% to 21% target range by 2017. However, the Companies plan to revisit the supply situation based on the development of load and market conditions. The [redacted] PPA is a means to support reliability by staying within the reserve margin range in the near term while minimizing revenue requirements and monitoring the development of load over the next 12 to 24 months.

Table 9 – LG&E/KU Resource Summary w/ PPA (MW, Summer, 2014 LF with Muni Termination)

	2015	2016	2017	2018	2019
Forecasted Peak Load	7,364	7,450	7,536	7,623	7,663
Energy Efficiency/DSM	(336)	(365)	(394)	(423)	(406)
Terminating Municipals	0	0	(16)	(16)	(325)
Net Peak Load	7,028	7,085	7,126	7,183	6,932
Existing Resources	7,792	7,775	7,775	7,775	7,775
Firm Purchases (OVEC)	155	155	155	155	155
Curtailable Demands	131	131	131	131	131
[redacted]	165	165	165	165	0
Total Supply	8,243	8,226	8,226	8,226	8,061
Reserve Margin ("RM")	17.3%	16.1%	15.4%	14.5%	16.3%
RM Shortfall (21%)	(262)	(347)	(397)	(466)	(326)
RM Shortfall (16%)	90	8	(40)	(107)	20

*Negative values reflect reserve margin shortfalls.

4 Utility Ownership Calculation

Since the merger of LG&E and KU, the Companies have determined utility ownership splits for twelve jointly-owned units: Cane Run 7 ("CR7"), Trimble County 2 ("TC2"), and ten SCCTs at the Trimble County, E.W. Brown, and Paddy's Run stations. The methodology used to determine the ownership split is dependent on the type of generating unit. For units like CR7 and TC2 that are expected to provide significant energy to customers, the ownership split is based on the expected energy benefits to each company. For peaking units like SCCTs, the ownership split is determined based on providing capacity for each utility's projected reserve margin need.

In 2011, the Companies determined an ownership split for CR7 of 78% for KU and 22% for LG&E, based on the energy needs of the utilities. The Companies also proposed to purchase all three Bluegrass SCCTs (495 MW) from LS Power.[4] Based on capacity needs to maintain reserve margins, the proposed ownership split for the Bluegrass facility was 69% for LG&E and 31% for KU. Based on this ownership, the 2014 IRP forecasted reserve margins for the 2015-2018 period would have been 19-21% for KU and 20-23% for LG&E. However, since the Companies could not complete the purchase as proposed, the forecasted reserve margins over the same period are 15-18% for KU, but only 8-10% for LG&E.

Consistent with previous SCCT facilities, the ownership split for the [redacted] was developed based on each utility's projected reserve margin need over the PPA period. Considering the [redacted] over the 2015-2018 period, 100% of the PPA costs should be allocated to LG&E. This ownership allocation increases the 2015-2018 forecasted reserve margin to 14-16% for LG&E, while maintaining KU's forecasted reserve margin range of 15-18%.

[4] The Companies were ultimately forced to terminate their agreement with LS Power due to an unfavorable Federal Energy Regulatory Commission ("FERC") ruling.

5 Appendix A – Available Transmission Capacity

Percentage of Time Monthly Firm Available for Export							
Source - May 23, 2014 ATC Posting							
Export Source	EEI	LGEE	MISO	OMU	OVEC	PJM	TVA
BLGR	N/A	94%	65%	0%	71%	71%	12%
EEI	N/A	0%	N/A	0%	0%	0%	N/A
KMPA	N/A	35%	82%	0%	35%	24%	65%
LGEE	0%	76%	76%	0%	71%	82%	29%
MISO	N/A	71%	N/A	65%	N/A	N/A	94%
OMU	29%	47%	47%	N/A	47%	29%	29%
OVEC	47%	88%	82%	71%	N/A	N/A	82%
PJM	0%	59%	N/A	0%	N/A	N/A	82%
TVA	94%	59%	100%	0%	82%	94%	N/A

Source: LG&E/KU ITO Stakeholder Meeting, June 25, 2014.

Based on the table above, monthly firm transmission is not consistently available from EEI or TVA to LGEE.

Case No. 2014-00321 IC Memorandum

Attachment 4

Case No. 2014-00321

Questions for Informal Conference Request for Information

1. Refer to page 3 of the Application, paragraph 6, which states that the Companies will deliver the energy from the designated Bluegrass Generation Company, LLC ("Bluegrass") Unit No. 3 ("Bluegrass Unit 3") to their native load customers using firm network transmission service and that the Companies have submitted a transmission service request for the contracted capacity of the unit. To whom have the Companies submitted the request and when is a response expected?

2. Refer to page 4 of the Application, paragraph 7. Provide the supporting calculations for the amounts in the table included in this paragraph.

3. Refer to pages 5 and 6 of the Application, paragraphs 9 and 10, wherein the Companies discuss their request to recover the cost of fuel and fuel transportation costs through the fuel adjustment clause, subject to six-month and two-year reviews conducted pursuant to 807 KAR 5:056. State whether the Companies intend to treat Bluegrass Unit 3 as owned by the Companies when responding to information requests issued in the fuel adjustment clause review cases. If no, explain.

4. Refer to page 6 of the Application, paragraph 12. Provide the amount of the minimum payment the Companies will be obligated to pay during each calendar year pursuant to the Capacity Purchase and Tolling Agreement.

5. Refer to Exhibit 5 of the Application, The Capacity Purchase and Tolling Agreement.

a. Confirm that the Delivery Commencement Date in Article 1 on page 3 is May 1, 2015. That being the case, explain why the Companies have requested an Order in this proceeding by November 18, 2014.

b. Refer to Article 3.3(a)(iii) on page 11. State whether approval of the agreement is needed from the Virginia State Corporation Commission. If so, provide details of that proceeding and the status of that approval process.

c. Refer to Article 3.3(a)(v) on page 11. Explain how the firm transportation service amount shown here was determined.

d. Refer to Article 4.2 on pages 12 and 13. Explain whether the use of an Alternate Source as discussed in this section will have any impact on the gas supply the Companies are providing for the generation of electricity.

e. Refer to Article 4.7 on page 14. Explain whether the 50 percent monthly availability factor for two months over a rolling twelve month period is an industry standard for these types of agreements or is specific to the Agreement based on the parties' negotiations.

f. Refer to Article 5.1 on page 14 which states that "Buyers will also arrange for Natural Gas for each Turbine Start in the amount of three hundred fifty (350) MMBtu." State whether this is required for all three of the units at the Bluegrass station. If yes, explain why it is required for all three units.

g. Refer to Article 5.3(b) on page 15. Explain whether the Companies intend to install additional meters at their own cost beyond their share of the cost of the

Natural Gas Pseudo Meter discussed in Article 5.3(c) and in Exhibit G. If so, provide the estimated cost of additional natural gas metering.

h. Refer to Article 8.5(a) on page 20. Explain whether the Companies anticipate that Seller's records, being subject to the two year record retention provision of this section, may be needed by the Companies' in conjunction with a Commission-initiated two-year FAC review. If so, explain whether the Companies believe there is need for an amendment to this section of the Agreement.

i. Refer to Article 9.1(a) on page 20. Explain the necessity for the first sentence in this section, and how it applies to the remainder of the section

j. Refer to Article 12.5 on page 26. Explain, from the Companies' perspective, the rationale for this specific arrangement regarding carbon dioxide taxes. The explanation should include how the $1/MWh was determined.

6. Provide a one-line diagram showing the LG&E transmission interconnection with Bluegrass.

Case No. 2014-00321 IC Memorandum

Attachment 5

Shaw, Jeff S (PSC)

From: Raff, Richard (PSC)
Sent: Friday, October 10, 2014 3:43 PM
To: Beyer, Jonathan (PSC); Faulkner, Leah (PSC); Shaw, Jeff S (PSC); Whelan, Chris (PSC); Gorjian, Fereydoon (PSC)
Subject: FW: KPSC Case No. 2014-00321

FYI.

From: Riggs, Kendrick R. [mailto:kendrick.riggs@skofirm.com]
Sent: Friday, October 10, 2014 2:56 PM
To: Raff, Richard (PSC)
Cc: Kurt J. Boehm (kboehm@BKLlawfirm.com); Kurtz, Michael L. (mkurtz@BKLlawfirm.com); Allyson K. Sturgeon (allyson.sturgeon@lge-ku.com)
Subject: KPSC Case No. 2014-00321

Richard,

Thank you for distributing the draft requests for information at the Informal Conference this morning. LG&E and KU appreciate the effort of the Staff to prepare the questions in advance of the Informal Conference, distributing the draft requests at the conference, and attaching the requests to the Staff IC memorandum. LG&E and KU will file responses to these requests for information no later than next Friday, October 17, 2014.

During the conference, Staff asked whether the requested November 18, 2014 date for the issuance of the order was essential. As discussed, the November 18, 2014 date is the end of the sixty-day period under KRS 278.300. While the November 18, 2014 date is a very desirable date for the issuance of the order, so long as the Commission issues the order by the end of November, 2014, LG&E and KU believe the timing of such an order will not prejudice their ability to move forward with implementing the agreement on a timely and orderly basis. With Thanksgiving Holiday period occurring at the end of the week of the November 24^{th}, LG&E and KU would ask that if the order cannot be issued by November 18^{th}, then the order be issued no later than November 26^{th}.

Should you have any further questions or need any additional information, please contact me at your first convenience.

Kendrick R. Riggs
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202
502.560.4222 (O)
502.627.8722 (F)
502.262.0172 (C)
kendrick.riggs@skofirm.com

Louisville | Lexington | Frankfort | Owensboro | Evansville | Greater Pittsburgh | skofirm.com