Exhibit 6

Analysis of May 2014 RFP Responses

PPL companies

Generation Planning & Analysis

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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.