COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of The Application Of: Electronic 2021 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company	: : :	Case No. 2021-00393

POST-HEARING COMMENTS OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Kentucky Industrial Utility Customers, Inc. ("KIUC") appreciates the opportunity to submit these Post-Hearing Comments.

Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU" or "Companies") have a hundred-year track record of providing low-cost, reliable power to their almost one million Kentucky ratepayers and their families. On issues of resource planning, they should be given the benefit of the doubt. Especially compared to parties that have a predetermined agenda. The Companies are sponsoring a least-cost plan to serve customers after the retirement of certain coal assets, even though a plan that relies more heavily on capital intensive renewables would be more profitable for them.

As filed, the least cost plan is: 440 MW simple cycle combustion turbines (SCCT) and 500 MW of solar in 2028, 880 MW of SCCT and 1,600 MW of solar in 2034, 100 MW of battery storage in 2035 and 100 MW of battery storage in 2036.[1] The SCCT are projected to have a relatively high heat rate of 9,700 and a correspondingly low-capacity factor of about 21%.[2] Solar is projected to have a capacity factor of 25.1% and will make no contribution to the winter peak.[3]

[1] IRP Vol. 3 p. 20.
[2] IRP Vol. 3 p. 11; IRP Vol. 1 p. 8-13.
[3] IRP Vol. 3 p.11.

As the case evolved, a different least cost plan emerged. That plan includes 513 MW of natural gas combined cycle ("NGCC") generation without carbon capture sequestration ("CCS") in 2028, 1,026 MW of NGCC generation without CCS in 2034 and 100 MW of battery storage in 2036.[4] Compared to the as filed plan, this plan has a present value revenue requirement ("PVRR") that is $80 million lower.[5] It also results in 8.6 million fewer tons of CO_2 emissions over fifteen years compared to the as filed plan.[6]

The new plan results in 8.6 million fewer tons of CO_2 primarily because NGCC generation displaces coal generation. A new NGCC will have at least the same 6,800 heat rate as Cane Run 7 and a capacity factor of about 80%.[7] A MWh of NGCC generation contains about 40% of the CO_2 compared to a MWh of coal generation. Because of its lower heat rate, NGCC generation is also less carbon intensive than SCCT generation even though both burn natural gas.

The following Table shows the CO_2 emissions per MWh of generation for certain of the Companies' existing base load coal, natural gas SCCT and natural gas NGCC units.[8]

	2021 Net Generation (MWh)	2021 CO_2 Emissions (Tons)	CO_2 Tons per MWh
Cane Run 7 Combined Cycle	4,751,590	1,949,859	0.41
Trimble County CT	823,715	551,458	0.67
Ghent Coal	10,582,328	11,356,348	1.07

[4] Response to Staff 2-1, update in JI 2-35 to Table 9-1 in Vol. I and Response to KIUC 3-1.
[5] Response to Staff 2-1, update in JI 2-35 to Table 9-1 in Vol. I and Response to KIUC 3-1.
[6] Response to Staff 2-1, update in JI 2-35 to Table 9-1 in Vol. I and Response to KIUC 3-1.
[7] IRP Vol. 1 p. 8-13.
[8] See attached.

It is not surprising that NGCC generation without CCS is more economic than SCCT generation. The incremental capital cost of adding a heat recovery steam generator is relatively small, but energy costs are at least 30% less. The assumption that CCS would not be required to be retrofit on an existing NGCC plant is reasonable. CCS is not commercially viable and is still in the research stage.[9]

In the PVRR analysis for NGCC generation, gas costs are the most significant component. Moreso than capital costs (rate base). But the Companies earn no return on fuel costs. If the Companies wanted to maximize their profits, then they would propose large amounts of solar generation. Solar is almost 100% rate base. Solar is highly capital intensive. It has no energy costs, and after construction solar generation employs virtually no one. Other utilities are cynically proposing to scrap their existing generation fleets as quickly as possible in order to replace them with 100% capital cost, zero fuel cost renewable generation. Thankfully, LG&E/KU are sticking to generation planning that is least cost for ratepayers, not generation planning that provides the maximum profit for shareholders.

The Companies' modeling assumption that there will not be a price or tax on CO2 emissions over the next fifteen years is reasonable. Kentucky has no renewable portfolio standard ("RPS") and is not likely to adopt one any time soon. Kentucky is also unlikely to join the Regional Greenhouse Gas Initiative ("RGGI") as that would simply raise rates on consumers and hurt the local economy while doing very little to address global climate change. Nor is Congress likely to tax energy. Federal administrative agency regulation of CO2 was made considerably less likely by the U.S. Supreme Court's recent ruling in *West Virginia v. Environmental Protection Agency*, 142 S. Ct. 2587 (2022).

[9] IRP Vol. I p. 8-34; IRP Vol. III Section 2.1.2.

Continued federal subsidization of wind, solar and battery storage through production tax credits ("PTC") and investment tax credits ("ITC") is likely. The recently enacted Inflation Reduction Act of 2022 underscores this. And the Companies included all PTCs and ITCs in their analysis.

If the Companies propose a new NGCC plant in a certificate of public convenience and necessity ("CPCN") case, and if the Commission approves that request, then the future ratemaking treatment will be important. Especially the assumed depreciable life of the plant. A short depreciation life would mean higher rates, but it would also reduce the possibility of future stranded costs. Securitization legislation would mitigate the stranded cost risk. It would not be unreasonable to address securitization in any CPCN case.

KIUC appreciates LG&E/KU's acknowledgement that "[r]*eliable, low-cost electricity is critically important to the Commonwealth's economy …* [because] [a]*s a leading manufacturer of automobiles, steel and other products, Kentucky was the 7th most electricity-intensive U.S. state in 2019, as measured by the ratio of electricity consumption and state gross domestic product."*[10] KIUC views LG&E/KU as essential suppliers of a critical service. Electricity costs vary widely among the states and can be the difference between new plants locating (Nucor Steel's new $1.35 Billion facility outside of Louisville to be served by Big Rivers and Ford's $5.8 Billion two new battery plants at the Glendale mega-site to be served by KU), existing plants expanding (the doubling of Nucor Steel's Gallatin plant served by EKPC) and existing plants closing (the temporary idling of Century Aluminum's Hawesville smelter because of high market electricity prices). This IRP process is an important part of maintaining Kentucky's low-cost electricity advantage.

[10] IRP Vol. I p. 5-1.

Respectfully submitted,

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ATTACHMENT

Cane Run CC | Plant Financials

Periods : Last Five Years

	2017 Y	2018 Y	2019 Y	2020 Y	2021 Y
Operational Statistics					
Operating Capacity (MW)	689.00	689.00	689.00	689.00	689.00
Summer Peak Capacity (MW)	663.00	663.00	663.00	663.00	663.00
Winter Peak Capacity (MW)	683.00	683.00	683.00	683.00	683.00
Net Generation (MWh)	3,567,737	4,711,123	5,163,403	4,589,220	4,751,590
Capacity Factor (%)	59.11	78.06	85.55	75.83	78.73
Heat Rate	7,078	6,787	6,800	6,801	6,863

Reported Plant Production Costs

Fuel Expenses

	2017 Y	2018 Y	2019 Y	2020 Y	2021 Y
Fuel Expense ($000)	84,147	104,961	100,838	79,187	111,117
Fuel Expense ($/MWh)	23.59	22.28	19.53	17.25	23.39
Estimated Fuel Cost?	No	No	No	No	No

Non-Fuel Operating & Maintenance Expenses

	2017 Y	2018 Y	2019 Y	2020 Y	2021 Y
Operating Supervision and Engineering ($)	1,292,409	1,466,768	1,541,971	915,459	728,382
Steam Expense ($)	0	0	0	0	0
Steam Transferred (Credit) ($)	0	0	0	0	0
Electric Expense ($)	3,847,730	5,265,762	5,675,662	6,091,383	6,286,784
Miscellaneous Power Expenses ($)	0	0	0	0	0
Rental Expense ($)	0	0	0	0	0
Allowance Expense ($)	0	0	0	0	0
Non-fuel Operating Expense ($)	5,140,139	6,732,530	7,217,633	7,006,842	7,015,166

Cane Run CC | Plant Environmental

Periods: Last Five Years

Emissions Control Equipment

FGD Control Installed?	No
FGP Control Installed?	No
NOx Control Installed?	No
Mercury Control Installed?	No

Emissions

	2017	2018	2019	2020	2021
CO2 Emissions (tons)	1,430,961	1,937,073	2,112,662	1,878,988	1,949,859
CO2 Emissions Rate (lb/MMBtu)	118.8573	118.8570	118.8576	118.8572	118.8569
NOX Emissions (lbs)	634,662	859,651	882,267	824,753	989,983
NOX Emissions Rate (lb/MMBtu)	0.0264	0.0264	0.0248	0.0261	0.0302
SO2 Emissions (lbs)	14,440	19,546	21,238	18,939	19,669
SO2 Emissions Rate (lb/MMBtu)	0.0006	0.0006	0.0006	0.0006	0.0006

Emission control equipment is sourced from primary research, EIA 923 and the EPA. Emission data is sourced from EPA's Continuous Emissions Monitoring System (CEMS). Byproducts are sourced from the EIA 923 filing.

Trimble County CT | Plant Financials

Periods : Last Five Years

	2017 Y	2018 Y	2019 Y	2020 Y	2021 Y
Operational Statistics					
Operating Capacity (MW)	1,074.00	1,074.00	1,074.00	1,074.00	1,074.00
Summer Peak Capacity (MW)	954.00	954.00	954.00	954.00	954.00
Winter Peak Capacity (MW)	1,074.00	1,074.00	1,074.00	1,074.00	1,074.00
Net Generation (MWh)	771,153	1,007,651	879,910	552,620	823,715
Capacity Factor (%)	8.20	10.71	9.35	5.86	8.76
Heat Rate	11,395	11,669	11,022	10,681	11,319
Reported Plant Production Costs					
Fuel Expenses					
Fuel Expense ($000)	49,712	60,503	47,341	33,690	59,435
Fuel Expense ($/MWh)	64.46	60.04	53.80	60.96	72.15
Estimated Fuel Cost?	No	No	No	No	No
Non-Fuel Operating & Maintenance Expenses					
Operating Supervision and Engineering ($)	0	13,302	0	0	0
Steam Expense ($)	0	0	0	0	0
Steam Transferred (Credit) ($)	0	0	0	0	0
Electric Expense ($)	658,619	747,701	669,349	948,852	818,342
Miscellaneous Power Expenses ($)	0	0	0	0	0
Rental Expense ($)	0	0	0	0	0
Allowance Expense ($)	0	0	0	0	0
Non-fuel Operating Expense ($)	658,619	761,003	669,349	948,852	818,342

Trimble County CT | Plant Environmental

Periods: Last Five Years

Emissions Control Equipment

FGD Control Installed?	No
FGP Control Installed?	No
NOx Control Installed?	No
Mercury Control Installed?	No

Emission Allowances

EMISSION ALLOWANCES	PROGRAM NAME	2019 HOLDINGS	AS OF
SO2	Acid Rain	NA	6/24/2019
NOx Ozone Season	CAIR NOx Ozone Season	NA	8/15/2016

Emissions

	2017	2018	2019	2020	2021
CO2 Emissions (tons)	526,671	667,270	563,138	364,167	551,458
CO2 Emissions Rate (lb/MMBtu)	118.8574	118.8580	118.8570	118.8557	118.8572
NOX Emissions (lbs)	289,544	372,773	321,830	210,298	312,065
NOX Emissions Rate (lb/MMBtu)	0.0327	0.0332	0.0340	0.0343	0.0336
SO2 Emissions (lbs)	5,321	6,775	5,686	3,689	5,555
SO2 Emissions Rate (lb/MMBtu)	0.0006	0.0006	0.0006	0.0006	0.0006

Emission control equipment is sourced from primary research, EIA 923 and the EPA. Emission data is sourced from EPA's Continuous Emissions Monitoring System (CEMS). Byproducts are sourced from the EIA 923 filing.

Ghent | Plant Financials

Periods : Last Five Years

	2017 Y	2018 Y	2019 Y	2020 Y	2021 Y
Operational Statistics					
Operating Capacity (MW)	1,943.00	1,943.00	1,943.00	1,943.00	1,943.00
Summer Peak Capacity (MW)	1,919.00	1,919.00	1,919.00	1,919.00	1,919.00
Winter Peak Capacity (MW)	1,918.00	1,918.00	1,918.00	1,918.00	1,918.00
Net Generation (MWh)	11,762,287	11,264,692	10,164,161	9,910,719	10,582,328
Capacity Factor (%)	69.11	66.18	59.72	58.07	62.17
Heat Rate	10,881	11,083	11,045	10,724	10,718
Reported Plant Production Costs					
Fuel Expenses					
Fuel Expense ($000)	257,786	238,904	214,402	204,307	220,874
Fuel Expense ($/MWh)	21.92	21.21	21.09	20.61	20.87
Estimated Fuel Cost?	No	No	No	No	No
Non-Fuel Operating & Maintenance Expenses					
Operating Supervision and Engineering ($)	3,989,950	3,802,306	4,215,297	2,428,153	2,298,453
Steam Expense ($)	13,923,346	11,395,446	9,087,926	10,349,012	11,160,968
Steam Transferred (Credit) ($)	0	0	0	0	0
Electric Expense ($)	5,070,282	5,253,783	5,573,247	5,326,986	5,673,054
Miscellaneous Power Expenses ($)	22,179,837	17,613,057	15,817,296	17,753,301	17,827,094
Rental Expense ($)	0	0	0	0	0
Allowance Expense ($)	3,645	3,162	2,116	1,902	2,151
Non-fuel Operating Expense ($)	45,167,060	38,067,754	34,695,882	35,859,354	36,961,720

Ghent | Plant Environmental

Periods: Last Five Years

Emissions Control Equipment

FGD Control Installed?	Yes
FGP Control Installed?	Yes
NOx Control Installed?	Yes
Mercury Control Installed?	Yes

Emission Allowances

EMISSION ALLOWANCES	PROGRAM NAME	2019 HOLDINGS	AS OF
SO2	Acid Rain	50,037	6/24/2019
NOx Ozone Season	CAIR NOx Ozone Season	NA	8/15/2016
NOx Annual	CAIR NOx Annual	NA	8/15/2016

Emissions

	2017	2018	2019	2020	2021
CO2 Emissions (tons)	11,976,737	11,725,848	10,824,178	10,547,036	11,356,348
CO2 Emissions Rate (lb/MMBtu)	205.2003	205.2001	205.2004	205.2003	205.2002
NOX Emissions (lbs)	14,097,216	13,229,792	12,701,725	10,673,849	13,168,436
NOX Emissions Rate (lb/MMBtu)	0.1208	0.1158	0.1204	0.1038	0.1190
SO2 Emissions (lbs)	17,267,427	21,241,317	17,092,778	17,201,329	22,119,987
SO2 Emissions Rate (lb/MMBtu)	0.1479	0.1859	0.1620	0.1673	0.1998

Byproducts

	2017	2018	2019	2020	2021
Fly Ash: Disposed or Sold Quantity (1000 tons)	494.3	486.1	495.1	313.8	NA
Bottom Ash: Disposed or Sold Quantity (1000 tons)	53.5	89.3	82.0	78.5	NA
Sludge: Disposed or Sold Quantity (1000 tons)	NA	NA	NA	NA	NA
Gypsum: Disposed or sold Quantity (1000 tons)	852.6	762.5	675.1	741.2	NA
Other Byproducts: Disposed or Sold Quantity (1000 tons)	NA	NA	NA	NA	NA
Fly Ash Collection and Disposal Expense ($000)	6,210	7,333	7,058	5,310	NA
Bottom Ash Collection and Disposal Expense ($000)	1,552	1,833	1,765	1,328	NA
Water Pollution: Abatement Collect & Disposal Exp ($000)	149	165	50	579	NA