COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of: ELECTRONIC 2023	:	
INTEGRATED RESOURCE PLAN OF BIG RIVERS	:	Case No. 2023-00310
ELECTRIC CORPORATION.	:	

COMMENTS OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Kentucky Industrial Utility Customers, Inc. ("KIUC") submits the following Comments on Big Rivers Electric Corporation's ("Big Rivers") 2023 Integrated Resource Plan ("IRP").

I. Big Rivers' Plan to Construct a New 635 MW Natural Gas Combined Cycle Plant is A Reasonable and Practical Solution To Address Its Future System Needs.

In its 2023 IRP, Big Rivers presents a Base Case scenario under which Green Units 1 and 2 are retired in May 2029 and a new 635 MW natural gas combined cycle ("NGCC") plant is constructed with an in-service date of June 2029.[1] Building an NGCC is a reasonable and practical plan to address Big Rivers' capacity needs once Green retires. NGCCs provide baseload energy in an efficient manner. NGCCs have low heat rates and low forced outage rates, resulting in reliable, low-cost generation. Additionally, an NGCC built near the current Green Station site would require minimal additional electric transmission infrastructure and gas pipeline infrastructure. Environmental permitting should be easier if the emission reductions from the retired Green Units can be netted against future NGCC emissions. Whereas renewable resources can provide significant energy value, they have low capacity values. Natural gas combustion turbine peaking units provide significant capacity value, but low energy value due to their

[1] IRP at 142.

relatively high heat rates. An NGCC would provide both substantial energy and capacity value to the system.

II. Big Rivers' Unilateral Decision To Modify Its MISO Peak Load And Energy Forecasting Methodology Is Unreasonable And Will Unnecessarily Increase Member Rates By Accelerating The Need For New Generation.

Big Rivers' 2023 IRP makes a major change to its peak load forecasting methodology regarding the treatment of standby service customer load. Rather than adhering to its historic practice of reflecting only the firm service level of standby service customers in its peak load forecast, Big Rivers now reflects the total load of standby service customers starting in 2025.[2] In other words, instead of continuing to plan on only serving net standby load (total load less the MISO-approved capacity value of the behind-the-meter cogeneration), Big Rivers' new planning ignores the capacity value of behind-the-meter cogeneration. The same change occurred regarding its energy forecasting. Beginning in 2025, it now plans to serve the full energy requirements of standby service customers, instead of its historic practice of planning to serve only the partial energy requirements of those customers.

This new approach to capacity and energy planning is seemingly based upon Big Rivers' assumption that its proposed standby service pricing proposal currently at issue in Case No. 2023-00312 will be adopted by the Commission. This standby rate proposal is premised on the assumption that Big Rivers must plan to serve the full load of standby service customers because no behind-the-meter generation is 100% reliable and that generation could be forced out during critical peak hours. It is also grounded in Big Rivers' unilateral decision to treat the generation of its standby service customers as a MISO capacity resource rather than a resource used to reduce its MISO demand. The IRP discusses this peak load forecasting change. *"There is one Direct Serve consumer that is currently served as partial requirement that is expected to*

[2] IRP, Appendix A at Page A-91-93.

transition to full requirement in the forecast period. In the 2023 study, the modeling database was revised to include this customer's full load."[3] The IRP also discusses the change to energy forecasting. *"One of the Direct Serve consumers only partially contributes energy to the Big Rivers energy requirements. Beginning in 2025, this load is projected to fully count towards the Big Rivers energy requirements."*[4]

Big Rivers' IRP peak load and energy forecasting changes are unreasonable and will harm ratepayers. In the IRP, the average firm load of one of Big Rivers' standby service customers – Domtar Paper Co., LLC ("Domtar") – over the 2018 through 2024 period was 19,286 kW.[5] Only Domtar's firm load was reflected in Big Rivers' total system peak demand forecast.[6] However, beginning in 2025, the IRP reflects Domtar's total load without regard to its behind-the-meter cogeneration.[7] The unforced capacity ("UCAP") value of Domtar's cogeneration unit is approximately 49 MW. The IRP also reflects the total load of standby service customer Kimberly-Clark Corporation ("Kimbelry-Clark") and ignores its 14 MW behind-the-meter cogeneration.

Big Rivers' peak load forecasting change to ignore the capacity value that MISO assigns to behind-the-meter cogeneration increases its system planning capacity requirement by 49 MW plus 14 MW plus a 25% reserve margin, or 78.75 MW.

Increasing Big Rivers' capacity requirement by 78.75 MW (and associated energy requirements) accelerated the need for the new 635 MW NGCC, which will increase costs on ratepayers. According to U.S. Energy Information Administration ("EIA") data, the cost of a new single-shaft NGCC in 2022 was $1,330 per kW. The cost of a new NGCC with 90% Carbon

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[3] IRP, Appendix A at Page A- 70.
[4] IRP, Appendix A at Page A- 33.
[5] IRP, Appendix A at Page A-91.
[6] Id.
[7] Id.

Capture and Sequestration ("CCS") in 2022 was $3,019 per kW.[8] In Data Responses, Big Rivers indicated that it modeled the new NGCC with CCS.[9] Multiplying the 78.75 MW of increased capacity requirement by the cost of a new single-shaft NGCC results in an additional cost to ratepayers of $104.7 million.[10] Multiplying the 78.75 MW of increased capacity requirements by the cost of a new NGCC with 90% CCS results in an additional cost to ratepayers of $237.7 million.[11]

Why would a cooperative utility unilaterally change its generation planning in a way that increases the long-term costs of its members? The most likely answer is that Big Rivers changed its long-term planning in order to increase its short-term margins. If its proposed standby rate is approved, then Big Rivers will immediately receive a $6.48 million annual rate increase from Domtar. Kimberly-Clark is currently on the Pilot LICSS standby rate. Because the proposed permanent LICSS standby rate is more costly to the customer, if approved, Big Rivers will also receive a rate increase from Kimberly-Clark. Short-term margins should not drive long-term IRP planning.

[8] EIA, *Cost and Performance Characteristics of New Generating Technologies*, Annual Energy Outlook 2023, Table 1 (attached).

[9] Big Rivers Response to Staff's First Requests for Information, Item No. 1-42.

[10] 78,750 KW x $1,330.

[11] 78,750 x $3,019.

CONCLUSION

Big Rivers' plan to construct a new NGCC to satisfy its capacity needs once the Green Station retires is reasonable. However, Big Rivers' major change to its peak load and energy forecasting methodology regarding the behind-the-meter cogeneration of its standby service customers is unreasonable and will unnecessarily accelerate the need for the NGCC.

Respectfully submitted,

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ATTACHMENT

March 2023

Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2023*

These tables are also published in the Electricity Market Module chapter in our *Annual Energy Outlook 2023* (AEO2023) Assumptions document. Table 1 includes our estimates of development and installation costs for various generating technologies used in the electric power sector. Typical generating technologies for end-use applications, such as combined heat and power or roof-top solar photovoltaics (PV), are described elsewhere in the Assumptions document. The costs in Table 1, except as noted below, are the costs for a typical facility for each generating technology before adjusting for regional cost factors. Overnight costs exclude interest accrued during plant construction and development. Technologies with limited commercial experience might include a technological optimism factor to account for the tendency to underestimate the full engineering and development costs for new technologies during technology research and development.

All technologies demonstrate some degree of cost variability, based on project size, location, and access to key infrastructure (such as grid interconnections, fuel supply, and transportation). For wind and solar PV, in particular, the cost favorability of the lowest-cost regions compound the underlying variability in regional cost and create a significant difference between the unadjusted costs and the capacity-weighted average national costs, as observed from recent market experience. To reflect this difference, we report a weighted average cost for both wind and solar PV, based on the regional cost factors assumed for these technologies in AEO2023 and the actual regional distribution of the builds that occurred in 2021 (Table 1).

Table 2 shows a full listing of the overnight costs for each technology and electricity region, if the resource or technology is available to be built in the given region. The regional costs reflect the impact of locality adjustments, including one to address ambient air conditions for technologies that include a combustion turbine and one to adjust for additional costs associated with accessing remote wind resources. Temperature, humidity, and air pressure can affect the available capacity of a combustion turbine, and our modeling addresses these possible effects through an additional cost multiplier by region. Unlike most other generation technologies where fuel can be transported to the plant, wind generators must be located in areas with the best wind resources. Sites that are located near existing transmission with access to a road network or are located on lower development-cost lands are generally built up first, after which additional costs may be incurred to access sites with less favorable characteristics. We represent this trend through a multiplier applied to the wind plant capital costs that increases as the best sites in a region are developed.

Table 1. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[a]	Size (MW)	Lead time (years)	Base overnight cost[b] (2022$/kW)	Techno-logical optimism factor[c]	Total overnight cost[d,e] (2022$/kW)	Variable O&M[f] (2022$/MWh)	Fixed O&M (2022$/kWy)	Heat rate[g] (Btu/kWh)
Ultra-supercritical coal (USC)	2026	650	4	$4,507	1.00	$4,507	$5.06	$45.68	8,638
USC with 30% carbon capture and sequestration (CCS)	2026	650	4	$5,577	1.01	$5,633	$7.97	$61.11	9,751
USC with 90% CCS	2026	650	4	$7,176	1.02	$7,319	$12.35	$67.02	12,507
Combined-cycle—single-shaft	2025	418	3	$1,330	1.00	$1,330	$2.87	$15.87	6,431
Combined-cycle—multi-shaft	2025	1,083	3	$1,176	1.00	$1,176	$2.10	$13.73	6,370
Combined-cycle with 90% CCS	2025	377	3	$3,019	1.04	$3,140	$6.57	$31.06	7,124
Internal combustion engine	2024	21	2	$2,240	1.00	$2,240	$6.40	$39.57	8,295
Combustion turbine—aeroderivative[h]	2024	105	2	$1,428	1.00	$1,428	$5.29	$18.35	9,124
Combustion turbine—industrial frame	2024	237	2	$867	1.00	$867	$5.06	$7.88	9,905
Fuel cells	2025	10	3	$6,771	1.08	$7,291	$0.66	$34.65	6,469
Nuclear—light water reactor	2028	2,156	6	$7,406	1.05	$7,777	$2.67	$136.91	10,447
Nuclear—small modular reactor	2028	600	6	$7,590	1.10	$8,349	$3.38	$106.92	10,447
Distributed generation—base	2025	2	3	$1,915	1.00	$1,915	$9.69	$21.79	8,912
Distributed generation—peak	2024	1	2	$2,300	1.00	$2,300	$9.69	$21.79	9,894
Battery storage	2023	50	1	$1,270	1.00	$1,270	$0.00	$45.76	NA
Biomass	2026	50	4	$4,996	1.00	$4,998	$5.44	$141.50	13,500
Geothermal[i, j]	2026	50	4	$3,403	1.00	$3,403	$1.31	$153.98	8,881
Conventional hydropower[j]	2026	100	4	$3,421	1.00	$3,421	$1.57	$47.06	NA
Wind[e]	2025	200	3	$2,098	1.00	$2,098	$0.00	$29.64	NA
Wind offshore[i]	2026	400	4	$5,338	1.25	$6,672	$0.00	$123.81	NA
Solar thermal[i]	2025	115	3	$8,732	1.00	$8,732	$0.00	$96.10	NA
Solar photovoltaic (PV) with tracking[e, i, k]	2024	150	2	$1,448	1.00	$1,448	$0.00	$17.16	NA
Solar PV with storage[i, k]	2024	150	2	$1,808	1.00	$1,808	$0.00	$32.42	NA

Data source: Sargent & Lundy, Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, December 2019; Hydroelectric: Oak Ridge National Lab, An Assessment of Energy Potential at Non-Powered Dams in the United States, 2012, and Idaho National Engineering and Environmental Laboratory, Estimation of Economic Parameters of U.S. Hydropower Resources, 2003; Geothermal: National Renewable Energy Laboratory, Updated U.S. Geothermal Supply Curve, 2010.

Note: MW=megawatt, kW=kilowatt, MWh=megawatthour, kWy=kilowattyear, kWh=kilowatthour; Btu=British thermal unit

[a] The first year that a new unit could become operational.

[b] Base cost includes project contingency costs.

[c] We apply the technological optimism factor to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[d] Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2023.

[e] Total overnight cost for wind and solar PV technologies in the table are the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2021 in each region to account for the substantial regional variation in wind and solar costs (Table 2). The input value used for onshore wind in AEO2023 was $1,566 per kilowatt (kW), and for solar PV with tracking, it was $1,443/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.

[f] O&M=operations and maintenance

[g] The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, *Annual Electric Generator Report*. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated, and electricity-to-storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion, and no set British thermal unit conversion factors exist. The module calculates the average heat rate for fossil-fuel generation in each year to report primary energy consumption displaced for these resources.

[h] Combustion turbine aeroderivative units can be built by the module before 2024, if necessary, to meet a region's reserve margin.

[i] Capital costs are shown before investment tax credits are applied.

[j] Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and the Great Basin region for geothermal, where most of the proposed sites are located.

[k] Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

Table 2. Total overnight capital costs of new electricity generating technologies by region

2022 dollars per kilowatt

Technology	1 TRE	2 FRCC	3 MISW	4 MISC	5 MISE	6 MISS	7 ISNE	8 NYCW	9 NYUP	10 PJME	11 PJMW	12 PJMC	13 PJMD
USC	$4,188	$4,311	$4,711	$4,835	$4,892	$4,334	$5,222	NA	$5,104	$5,269	$4,495	$5,664	$4,851
USC with 30% CCS	$5,281	$5,421	$5,852	$6,011	$6,058	$5,456	$6,463	NA	$6,334	$6,504	$5,632	$6,914	$6,055
USC with 90% CCS	$6,907	$7,083	$7,558	$7,812	$7,820	$7,152	$8,281	NA	$8,068	$8,294	$7,292	$8,831	$7,750
CC—single-shaft	$1,200	$1,225	$1,366	$1,379	$1,414	$1,236	$1,594	$2,116	$1,599	$1,597	$1,324	$1,600	$1,524
CC—multi-shaft	$1,045	$1,072	$1,215	$1,236	$1,268	$1,084	$1,393	$1,909	$1,370	$1,401	$1,147	$1,469	$1,295
CC with 90% CCS	$2,945	$2,972	$3,175	$3,182	$3,231	$2,999	$3,334	$3,776	$3,258	$3,307	$3,041	$3,447	$3,168
ICE	$2,106	$2,152	$2,300	$2,391	$2,365	$2,182	$2,451	$3,073	$2,359	$2,452	$2,197	$2,673	$2,282
CT—aeroderivative	$1,263	$1,289	$1,494	$1,498	$1,543	$1,316	$1,607	$2,057	$1,551	$1,598	$1,370	$1,755	$1,454
CT—industrial frame	$764	$781	$907	$911	$939	$798	$978	$1,262	$942	$973	$830	$1,072	$883
Fuel cells	$6,996	$7,105	$7,430	$7,750	$7,603	$7,224	$7,887	$9,285	$7,567	$7,819	$7,204	$8,337	$7,425
Nuclear—light water reactor	$7,341	$7,499	$7,917	$8,637	$8,330	$7,744	$8,809	NA	$8,219	$8,608	$7,608	$9,465	$7,918
Nuclear—small modular reactor	$7,779	$7,962	$8,674	$9,044	$9,041	$8,061	$9,338	NA	$8,894	$9,357	$8,160	$10,440	$8,474
Distributed generation—base	$1,729	$1,764	$1,967	$1,986	$2,036	$1,779	$2,296	$3,047	$2,302	$2,300	$1,907	$2,304	$2,195
Distributed generation—peak	$2,034	$2,076	$2,405	$2,412	$2,485	$2,119	$2,587	$3,312	$2,497	$2,573	$2,206	$2,827	$2,341
Battery storage	$1,270	$1,273	$1,255	$1,316	$1,273	$1,300	$1,309	$1,304	$1,275	$1,278	$1,267	$1,283	$1,278
Biomass	$4,637	$4,764	$5,157	$5,329	$5,340	$4,802	$5,933	$8,054	$5,952	$6,056	$5,093	$6,067	$5,804
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Conventional hydropower	$4,992	$6,098	$2,426	$1,612	$3,283	$4,858	$2,248	NA	$4,599	$4,777	$4,164	NA	$4,226
Wind	$3,059	NA	$1,723	$1,566	$1,875	$1,566	$2,075	NA	$2,531	$2,075	$1,566	$2,281	$2,161
Wind offshore	$6,517	$7,819	$7,714	NA	$7,989	NA	$7,783	$6,714	$8,139	$7,461	$6,100	$8,834	$6,950
Solar thermal	$8,424	$8,551	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Solar PV with tracking	$1,422	$1,395	$1,443	$1,497	$1,480	$1,407	$1,494	$1,758	$1,480	$1,524	$1,440	$1,571	$1,436
Solar PV with storage	$1,751	$1,769	$1,822	$1,880	$1,854	$1,787	$1,892	$2,150	$1,858	$1,896	$1,780	$1,971	$1,842

Technology	14 SRCA	15 SRSE	16 SRCE	17 SPPS	18 SPPC	19 SPPN	20 SRSG	21 CANO	22 CASO	23 NWPP	24 RMRG	25 BASN
USC	$4,337	$4,401	$4,460	$4,366	$4,638	$4,415	$4,600	NA	NA	$4,874	$4,556	$4,754
USC with 30% CCS	$5,460	$5,511	$5,593	$5,475	$5,778	$5,526	$5,765	NA	NA	$6,059	$5,704	$5,918
USC with 90% CCS	$7,165	$7,228	$7,313	$7,127	$7,489	$7,178	$7,466	NA	NA	$7,833	$7,355	$7,697
CC—single-shaft	$1,220	$1,235	$1,273	$1,234	$1,309	$1,222	$1,201	$1,759	$1,719	$1,399	$1,132	$1,224
CC—multi-shaft	$1,071	$1,085	$1,124	$1,083	$1,163	$1,074	$1,034	$1,547	$1,504	$1,213	$974	$1,092
CC with 90% CCS	$2,962	$2,977	$3,044	$2,966	$3,065	$2,921	$2,702	$3,389	$3,351	$3,126	$2,541	$2,854
ICE	$2,194	$2,200	$2,238	$2,178	$2,295	$2,200	$2,221	$2,661	$2,613	$2,367	$2,192	$2,347
CT—aeroderivative	$1,309	$1,320	$1,370	$1,318	$1,411	$1,327	$1,198	$1,687	$1,645	$1,480	$1,159	$1,322
CT— industrial frame	$793	$801	$831	$799	$857	$804	$726	$1,031	$1,004	$900	$702	$803
Fuel cells	$7,277	$7,271	$7,371	$7,144	$7,443	$7,209	$7,309	$8,375	$8,278	$7,655	$7,169	$7,636
Nuclear—light water reactor	$7,843	$7,782	$8,035	$7,530	$7,962	$7,527	$7,808	NA	NA	$8,451	$7,563	$8,460
Nuclear—small modular reactor	$8,101	$8,164	$8,349	$8,082	$8,583	$8,150	$8,258	NA	NA	$8,942	$8,170	$8,880
Distributed generation—base	$1,757	$1,778	$1,833	$1,777	$1,886	$1,760	$1,729	$2,533	$2,475	$2,014	$1,630	$1,763
Distributed generation—peak	$2,107	$2,126	$2,206	$2,123	$2,273	$2,137	$1,929	$2,716	$2,649	$2,383	$1,867	$2,128
Battery storage	$1,311	$1,293	$1,309	$1,264	$1,272	$1,257	$1,286	$1,323	$1,325	$1,300	$1,259	$1,310
Biomass	$4,820	$4,857	$4,921	$4,825	$5,126	$4,926	$5,276	$6,759	$6,606	$5,455	$5,227	$5,226
Geothermal	NA	NA	NA	NA	NA	NA	$3,468	$3,440	$2,785	$3,366	NA	$3,403
Conventional hydropower	$2,353	$5,104	$2,638	$5,049	$2,128	$2,000	$4,056	$4,291	$4,132	$3,421	$4,085	$4,464
Wind	$1,867	$2,116	$1,566	$1,566	$1,723	$1,723	$1,566	$3,458	$2,715	$2,283	$1,566	$1,566
Wind offshore	$6,005	NA	NA	NA	NA	NA	NA	$10,064	$10,558	$7,550	NA	NA
Solar thermal	NA	NA	NA	$8,509	$8,838	$8,422	$8,826	$10,397	$10,266	$9,394	$8,481	$9,413
Solar PV with tracking	$1,465	$1,392	$1,438	$1,394	$1,449	$1,404	$1,418	$1,579	$1,570	$1,453	$1,435	$1,448
Solar PV with storage	$1,799	$1,781	$1,802	$1,768	$1,826	$1,787	$1,796	$1,969	$1,964	$1,858	$1,789	$1,854

Data source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

Notes: Costs include contingency factors, regional cost multipliers, and ambient condition multipliers. Interest charges are excluded. The costs are shown before investment tax credits are applied.

NA=not available; plant type cannot be built in the region because of a lack of resources, sites, or specific state legislation.

USC=ultra-supercritical, CCS=carbon capture and sequestration, ICE=internal combustion engine, CC=combined cycle, CT=combustion turbine, PV=photovoltaic.

Electricity Market Module region map