Comments of PPL Corporation on Proposed New Source Performance Standards For Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines For Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

Docket No. EPA-HQ-OAR-2023-0072

August 8, 2023

PPL Corporation (PPL) appreciates the opportunity to comment on the proposed rule published by the U.S. Environmental Protection Agency (EPA) in the Federal Register on May 23, 2023, regarding actions under Section 111 of the Clean Air Act (CAA) to address greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs) consisting of steam electric generating units, natural gas combined cycle units (NGCC), and stationary combustion turbines (GHG Rules).

I. Introduction and Overview

PPL Corporation (PPL) is an energy company engaged in generation, transmission, and distribution of electricity and distribution of natural gas. Two of its subsidiaries – Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) - are Kentucky-based companies that provide natural gas and electricity to over 1.3 million customers in Kentucky and Virginia. These regulated utility companies own and operate power generation plants fueled by coal and natural gas, hydroelectric generation, and a growing portfolio of renewables. LG&E and KU are committed to supporting the future energy needs of their customers, including a growing manufacturing base, with an increasingly clean generation mix. In adopting and executing its comprehensive clean energy transition strategy and net-zero by 2050 goal, PPL is committed to preserving reliability, resilience, and affordability for our customers.

As the Administration continues to promote a whole-of-government approach to addressing climate change, PPL urges EPA to carefully consider the potential for initiatives like the GHG Rules to frustrate, rather than advance, the Administration's climate goals. The electric utility industry, including PPL, is hard at work in its ongoing transition to clean energy while avoiding undue cost and reliability impacts that could result in significant burdens for customers, and we urge EPA's careful consideration in ensuring a regulatory framework that supports, rather than hinders, these efforts. Decarbonization of electricity generation is a complex and challenging endeavor, particularly for historically heavily coal-based utilities such as PPL's Kentucky subsidiaries. To achieve the aims of the Administration, the final GHG Rules must provide for an achievable pathway and realistic means to manage this transition.

PPL believes it is both feasible and necessary for EPA to structure its final GHG Rules to support a clean energy transition that is both real and practical, without sacrificing sustainability, reliability, and affordability. As drafted, the proposed rule prematurely determines carbon capture and sequestration (CCS) and low GHG hydrogen co-firing as the Best System for Emission Reduction (BSER). Because these technologies have not been adequately demonstrated and are not realistically available within the timeframes specified by EPA, the proposed GHG Rules will have the practical effect of unnecessarily limiting the use of natural gas-fired generation and potentially crowding out alternative technologies and compliance measures. Additionally, by making continued operation of coal-fired EGUs during the interim period contingent on unrealistic capacity factor limitations and natural gas co-firing requirements, the proposed rule further injects significant affordability and reliability risk into the clean energy transition. Simply put, the proposed rule goes too far, too fast, and in doing so, jeopardizes a sustainable clean energy transition.

In drafting the proposed rule, EPA has seriously underestimated the technology and infrastructure challenges associated with effectively mandating the restructuring of an entire industry of critical importance to the economy and electrification effort. Unless EPA remedies these defects, PPL and other similarly situated companies simply would have no realistic pathway toward compliance, as discussed below. We urge EPA to carefully consider the complexities of decarbonization in promulgating a final rule.

II. PPL's Current GHG Reduction Plans

PPL has set an ambitious goal to achieve net-zero carbon emissions by 2050, as well as interim goals of 70% reduction by 2035 and 80% reduction by 2040. This is an aggressive, but realistic schedule that allows PPL to achieve its net-zero goal while continuing to provide reliable power to customers at prices they can afford to pay. PPL divested all non-regulated generation assets in 2015 and has retired 1,200 MW of regulated coal-fired generation from 2010 to date. Overall, PPL has already reduced its GHG emissions by almost 60% from 2010 levels and is implementing its goals and plans.

PPL's subsidiaries, LG&E and KU, recently applied for approval from the Kentucky Public Service Commission to retire nearly a third of their current coal-fired generation – 1,500 of 4715 MW – by 2028. LG&E and KU expect to retire another 2,300 MW by 2039[1]. This schedule reflects retirement of 81% of the companies' coal-fired generation by 2039. To meet the resource needs created by these economic retirements, LG&E and KU have also sought approval to construct two 621 MW combined cycle natural gas generation plants, construct or acquire two 120 MW solar photovoltaic generating facilities, construct a 125 MW, 4-hour, battery energy storage system facility, and implement expanded demand side management programs to reduce the need for 100 MW. Additionally, LG&E and KU are in the process of procuring 637 MW of energy from four solar voltaic generating facilities. This broad mix of projects would result in nearly a 25% reduction in GHG emissions from current levels and a corresponding 26% reduction in carbon intensity. Alternatively, replacing the rated generation capacity with only intermittent renewables would cost our customers $2.1 billion more over the next 30 years and would result in about 7% more GHG emissions due to the low-capacity factor of renewable generation and the resulting need to operate remaining fossil generation at a higher level to serve our customers.

As part of its planning process, PPL has assessed the feasibility of more drastic deployment of renewable energy generation. What we found is that achieving an 80% clean energy portfolio by 2030 would require investment of approximately $22 billion and would result in a 66% increase over today's generation costs.[2] Electricity bills would increase an average of 60% from 2022 to 2030. A $1.2 billion energy cost increase annually by 2030 for our industrial, large commercial, and small business customers would likely result in a negative impact on load and jobs. Our analysis shows that such an approach

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[1] Net-summer rating.
[2] This reflects production tax credits available under the Inflation Reduction Act of 2022 (without such tax credits, the cost increase would be 112%).

would be not only cost prohibitive, but also infeasible in light of the siting, permitting, construction, transmission, and other challenges. We believe our transition plan reflects the best mix of generation resources reasonably available to serve our customers in the most reliable, affordable way, while also achieving the greatest GHG reductions. In our planning, we will continue to consider all generation technology options available to us; reliance on unavailable technologies, however, would be inconsistent with our obligation to serve our customers.

III. The proposed GHG Rules Pose Significant Reliability and Affordability Risks for PPL's Customers.

As many commenters have pointed out in compelling detail, CCS and hydrogen co-firing are not "adequately demonstrated" and "achievable" as is required to constitute BSER under Section 111 of the CAA. Even apart from the legal questions, the practical implication of EPA's premature determination of CCS and hydrogen as BSER is that the ability to serve PPL's customers is at significant risk and there is no real-world ability for PPL to achieve compliance.

In determining CCS and hydrogen co-firing as BSER, the proposed GHG Rules effectively eliminate PPL's ability to operate its existing coal-fired EGUs beyond year-end 2031 and would necessitate 3,400 to 4,800 MW of replacement generation to be built in an aggressive timeframe. This is because long-term operation of existing units after year-end 2039 requires CCS capture of 90% by 2030, which is infeasible, and options for continued operation of existing coal-fired units during an intermediate period up through 2039 (natural gas co-firing and capacity factor limits) are likewise unrealistic from a real-world operating standpoint.

PPL is fully supportive of ongoing development of CCS and has itself been actively engaged in CCS research and development. The U.S. Department of Energy recently awarded funding for our CCS research and development project at LG&E's Cane Run plant, which highlights that the government is aware that CCS is not ready for commercial deployment at utility scale. Additionally, Kentucky lacks geology conducive to storage, and the pipeline and other infrastructure necessary for transport to potential storage formations outside the state is entirely lacking. Thus, it is highly unlikely that technology and infrastructure challenges of this magnitude can be overcome by 2030, as would be necessary to operate coal-fired EGUs beyond year-end 2039.

Co-firing with 40% natural gas fleetwide (a pathway to operate coal-fired EGUs through 2039) is likewise impracticable due to significant impediments to natural gas transportation, supply, and use. First, it is extremely unlikely that the necessary pipeline infrastructure and supply arrangements could be in place by 2030, as required. Necessary natural gas infrastructure exists at only one of the company's three coal-fired power plant sites today. Siting and permitting pose significant challenges for new pipelines to be built to the other two plant sites. Even if the pipelines to the plants could be built, it is unknown how much interstate pipeline capacity is available to accommodate incremental gas needs for co-firing and whether and how much additional firm gas transmission infrastructure would be needed and could be timely completed. Moreover, co-firing is extremely uneconomic and would impose significant incremental costs on our customers. Generally, co-firing increases costs by blending a more expensive fuel (on a per MMBtu basis) with a less expensive fuel with no improvements in efficiency, while introducing a new operating cost (firm gas transportation). On a macro level, an overall increase in demand for natural gas would put upward pressure on gas supply costs, directly affecting affordability for our customers. The proposed natural gas co-firing requirements are counterproductive from the standpoint of both economics and operational feasibility.

Limiting coal-fired EGUs to 20% capacity factor (a pathway to operate them through 2034) renders the units impractical and uneconomic. Coal-fired EGUs are designed for continuous operation necessary to serve base load needs and typically operate at a capacity factor in the 55% to 80% range. Coal-fired units also have long start times (generally more than 24 hours). Consequently, they are not a practical option to serve intermittent peak load needs or otherwise operate at a low capacity factor. Although coal-fired EGUs may operate at lower capacity factors under unusual circumstances, operating coal-fired units consistently at a 20% capacity factor would pose reliability problems and render them uneconomic. At most, this pathway could serve as a last resort option to manage, at significant cost, critical energy and capacity shortfalls prior to completion of replacement generation, rather than a realistic fleetwide compliance option. Limited to this short-term bridge role, it is of extremely limited value as a compliance tool.

For PPL, which is historically heavily coal-based, replacement of retired coal-based EGUs by year-end 2031 driven by CCS and hydrogen co-firing requirement provides an extremely limited glidepath for transition to lower GHG generation. If unable to operate its existing coal-fired EGUs beyond year-end 2031, PPL would have to replace all seven of its remaining coal-fired EGUs at three plant sites with new NGCC capacity and a combination of new renewables and storage totaling 3,400 to 4,800 MW, depending on economics. This would be incremental to our current proposal before the Kentucky Public Service Commission to construct two NGCC power plants, with a total capacity of 1,242 MW, during the 2024 to 2028 time period. Compliance with the rule, as proposed, would thus require construction of an additional six to eight comparable NGCCs and vast renewable generation by year-end 2031.

According to our preliminary analysis, the low end of the estimated capacity need (3,400 MW) reflects the <u>minimum capacity</u> needed to replace retiring coal capacity and serve nighttime energy requirements. Beyond the 3,400 MW minimum capacity, 1,400 MW of additional NGCC capacity would be needed to replace remaining <u>energy</u> from retired units, assuming a 50% capacity factor limitation beginning in 2032 by operation of the rules for NGCCs.[3] Alternatively, instead of the full 1,400 MW of additional NGCC capacity stated above, up to 2,800 MW of solar (at 25% capacity factor) or up to 2,000 MW of wind (at 35% capacity factor) could be built to provide the energy need, along with up to 500 MW of battery storage to assist with renewables integration.

The combined retirement of coal capacity and limits on NGCC capacity due to availability of CCS and hydrogen blending will drive reliability and affordability risks. As we understand the current generation and natural gas pipeline markets, it is almost certainly not possible in today's environment to add six to eight additional NGCCs (potentially in combination with high levels of renewable generation) to PPL's system before 2032. There are at least four significant roadblocks to such a rapid expansion of thermal generation. The first challenge would be ensuring that the needed natural gas infrastructure would be available in the required time frame. Natural gas transmission infrastructure is under control of the pipeline owner, rather than PPL. Based on recent history, siting and permitting challenges would likely result in protracted delay for any necessary projects. The next uncertainty is the capacity of the three international combustion turbine manufacturers to meet the massive demand for new machines that would result from the rule as proposed. Another hurdle is building electric transmission infrastructure to accommodate new generation. Lastly, it is unclear whether there is sufficient

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[3] According to the proposed GHG Rules, hydrogen blending by 2032 and CCS by 2035 are potential pathways that could eliminate the 50% capacity factor limitation, but as discussed above, it is highly questionable if such technology will be available and economic within the timeframe of the proposed rule.

construction capacity for engineering, procurement and construction (EPC) contractors to add the required level of NGCC capacity. The entire electric power industry would be competing for the same combustion turbine manufacturing and EPC resources within a limited timeline. Permitting and siting of renewables and supply chain constraints could further challenge the timing and availability of these resources.

For all prior programs governing operation of fossil fuel-fired EGUs established by EPA under the CAA, PPL's subsidiaries, LG&E and KU, have adopted physical compliance strategies (e.g., retrofitting existing units with new emission controls, constructing new units with state of the art controls, etc.). Because the forced glidepath in the proposed rule would provide insufficient time for construction of replacement generation (NGCCs and renewables) to meet system-wide needs as discussed above, LG&E and KU would face the prospect of relying on large scale power purchases on the wholesale market. With many of the energy suppliers serving the wholesale market facing the same regulatory pressures under the rule, the availability of adequate supply is seriously in question. Furthermore, coupling limited supply with greater demand raises the potential for significant increases in price. Based on our preliminary analysis, the rule, as proposed, would pose unprecedented reliability and affordability risks that could result in significant harm to the customers of PPL and many other electric utilities.

IV. The Proposed Rule Must Not Impede Deployment of Natural Gas-Fired Generation Necessary as a Partner to Renewables.

Because of their inherently intermittent nature, wind and solar renewable energy generating resources must be supported by thermal energy resources to ensure adequate reliability on a system-wide scale. Obviously, solar generation facilities require backup during night-time periods, while wind generation requires back up when wind speeds are low. Additionally, based on our own experience, PPL has learned that power generation from solar facilities during daylight hours can vary substantially minute-to-minute depending on factors such as cloud cover. Integration of intermittent renewables is a manageable problem at small scales, but large-scale deployment of intermittent renewable energy resources poses a major challenge in the operation of a utility generating fleet. Until energy storage and other technologies are further developed, there is no viable support resource other than quick-starting and ramping simple cycle natural gas-fired generation to meet the highly variable system demands posed by large-scale deployment of intermittent renewable generation.

Additionally, combined cycle natural gas generation is crucial as aging coal generation is economically retired. Combined cycle natural gas generation provides highly efficient, large-scale baseload capacity necessary to support needed replacement energy capacity, and natural gas generation emits GHGs at nearly one-third the level of coal-fired units. As such, EPA should not overlook the importance of natural gas generation in the new generation mix necessary to achieve significant GHG emission reductions while supporting capacity and energy needs. Without the support of expanded natural gas generation, large-scale deployment of renewable generation to replace retiring coal baseload generation will pose unacceptable system reliability problems. Furthermore, limiting the deployment of natural gas generation will result in substantial additional environmental compliance and electricity generation costs to be borne by utility customers.

PPL has no objection to the Phase I efficiency standards proposed for large new and existing natural gas EGUs. However, the Phase 2 and 3 requirements for BSER in the form of CCS and hydrogen co-firing are premature based on the early development stage of both technology and infrastructure in those areas. The hydrogen co-firing targets and compliance dates proposed by EPA are infeasible based on the current stage of development and are major impediments to continued use of natural gas-fired generation critical for the energy transition. The proposed rule provides for deployment of hydrogen co-firing and CCS by a date well beyond the eight-year review cycle specified in Section 111 for periodic review of existing standards. Currently, there are a number of federal programs, including the Inflation Reduction Act and Infrastructure Investment and Jobs Act, that are providing significant funding to "jump start" new technologies such as CCS and hydrogen co-firing. In light of these considerations, PPL urges EPA to take a two-step approach to setting GHG standards under Section 111: (1) immediately setting appropriate efficiency standards for fossil-fueled EGUs; and (2) reassessing those standards upon availability of new technologies or occurrence of the next statutory review period.

V. Other Comments

A. The proposed rule should be revised to add a reliability safety valve.

EPA's proposed rule compels massive changes in the current energy mix far beyond the mandates of any rule previously adopted under the CAA. As currently proposed, the rule requires deployment of new technologies such as CCS and hydrogen co-firing with which the electric utility industry has little or no experience. It is uncertain that equipment vendors and EPC contractors have sufficient capacity to serve the number of projects required under the proposed rule. The proposed rule requires construction of facilities such as pipelines and hydrogen production facilities that will be owned and operated by third parties not under the control of electric utilities. Finally, there is a well-established history of delays in obtaining permits and approvals for projects such as pipelines and electric transmission lines.

Under the aggressive timelines in the rule as currently proposed, there is a high risk that delays in deploying new technologies or necessary infrastructure could result in interruption of existing energy supplies necessary to serve the needs of utility customers. Such disruptions could result in harm to both individual customers and the economy at large. In most cases, the delays in question would be beyond the reasonable control of electric utilities subject to this rule. Under these circumstances, it is prudent for EPA to revise the proposed rule to provide a reliability safety valve provision allowing companies to seek an extension to or exemption from compliance deadlines if external factors prevent a unit from compliance with the rule, or if the Federal Energy Regulatory Commission or other similar reliability authority deems a unit essential for maintaining grid reliability. EPA should also provide a mechanism for units subject to capacity factor restrictions to operate beyond those restrictions for the purpose of stabilizing the grid during periods of extreme load or other system conditions that threaten reliability.

B. EPA should revise the proposed rule to provide additional flexibility including promulgation of a model trading rule.

Regulated electric utilities have the obligation to serve a broad range of customers with varying needs. Utilities must operate on a 24/7 basis under every conceivable condition ranging from heat wave to winter storm. To meet their obligations, it is critical for utilities to retain the operational flexibility necessary to meet the broad range of challenges that commonly arise. The need for operational flexibility is even more important in the face of the requirements in the proposed rule that mandate fundamental changes in the current energy mix. In finalizing the proposed rule, it is important for EPA to provide operational flexibility for EGUs and regulatory flexibility for the states to the maximum extent possible.

In the proposed rule, EPA acknowledges that a GHG emission allowance trading system could play an important role as a compliance tool providing operational flexibility and invites the states to establish appropriate allowance trading programs for implementation of the rule. However, most states lack the expertise, experience, and resources necessary to create a complex and effective allowance trading program from the ground up. On the other hand, EPA has extensive experience in establishing allowance trading programs under several provisions of the CAA. Without a high degree of EPA involvement and support, many states will likely find it impractical to establish GHG emission allowance trading programs. This would deprive electric utilities of a compliance tool that could be highly effective in mitigating reliability and affordability risks occurring in the energy transition. The most important step that EPA can take to provide compliance flexibility for the electric utility industry and support to the states is to promulgate a model emission allowance trading rule. A model rule would greatly facilitate adoption of that important tool at the state level.

In addition, EPA should provide states with flexibility in the form of alternative mass-based emission limits that are presumptively approvable. EPA should also allow the banking of tradeable compliance instruments and allow states to make appropriate changes to compliance subcategories under Section 111(d). Nothing in the final rule should unduly limit a state's discretion to take appropriate factors into account in establishing requirements, including the remaining useful life of an EGU. Adding these provisions will enhance flexibility necessary for reasonable and effective implementation of the rule.

C. Subcategories in the proposed rule should be revised to account for source variability.

As currently proposed, the rule establishes subcategories for coal-fired EGUs based on the operating horizon or retirement of the sources. Rather than assess sources with shared or similar physical attributes to inform a BSER determination, the rule focuses on generation shifting metrics relating to retirement of units. The baseline is based on a unit's last three years of operation prior to 2030. More appropriate subcategorization provisions would allow a utility to select the subcategory based on variation in unit efficiency. The proposed rule should be revised to account for the considerable variability within source categories, including remaining useful life, operating regime, size, and other considerations that may impact costs and feasibility.

D. New source performance standards relating to hydrogen should be addressed in a separate rule.

Potential limits on the extent of near-term hydrogen production and delivery raise serious questions about whether co-firing hydrogen at natural gas-fired EGUs is the highest value and lowest abatement cost use. EPA should conduct a comprehensive calculation of hydrogen costs that accounts for the uncertainty in hydrogen production deployment, operation, and infrastructure, and inherent regional variability. Hydrogen and new source performance standards relating to hydrogen should be considered separately to allow for the comprehensive evaluation which is necessary before adoption of final requirements.

E. Policy reform for facility siting and permitting is necessary for large-scale deployment of GHG reduction measures.

The proposed rule provides for large-scale deployment of new technologies such as CCS and hydrogen co-firing and expanded use of existing technologies such as co-firing of natural gas. The proposed rule will require massive expansion of renewable energy generating facilities. It will result in construction of pipelines for natural gas, hydrogen, and CO2 and extensive additions to the electric transmission grid. All of these facilities will be subject to a multitude of federal, state, and local permits and approvals. The process necessary to obtain project approvals from regulatory agencies routinely takes two or three years. For large projects such as interstate pipelines, the approval process often stretches to 10 years or more. Current regulatory review and permitting protocols are poorly suited for timely approval of the number of projects that are necessary for compliance with the proposed rule. The aggressive timelines under the proposed rule combined with existing dilatory permit review protocols are a prescription for disruption and delay of compliance measures necessary for the significant GHG reductions mandated by EPA. PPL believes that it is quite possible to establish regulatory review processes that provide for environmental reviews that are both appropriate and timely. We suggest that EPA work with other key agencies including the U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, Federal Energy Regulatory Commission, and relevant state agencies to identify and adopt appropriate permitting reforms that will provide for appropriate environmental reviews of the projects mandated under the proposed rule, while eliminating current administrative bottlenecks that result in routine project delays.

VI. Conclusion

PPL is committed to undertaking both the short-term and long-term actions necessary to advance our clean energy transition and reach our goal of net zero carbon emissions. As the owner of public utility subsidiaries, PPL is also obligated to provide its customers with electricity that is reliable and affordable. We do not consider these goals to be mutually exclusive. We urge EPA, in finalizing the proposed rule, to carefully consider the complexities inherent in the nation's ongoing energy transition and adopt appropriate revisions that support an orderly transition that allows us to continue to serve the reliability and affordability needs of our customers.

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