Joint Union Comments on Proposed U.S. EPA
Emission Guidelines for Greenhouse Gas Emissions From
Existing Fossil Fuel-Fired Electric Generating Units

EPA–HQ–OAR–2023–0072

88 Fed. Reg. 33240 (May 23, 2023)

Via Web to https://www.regulations.gov

These comments are submitted jointly by the International Brotherhood of Boilermakers, *et al.*, the International Brotherhood of Electrical Workers, the International Association of Bridge, Structural, Ornamental, and Reinforcing Iron Workers, the Transportation · Communications Union, IAM, and the United Mine Workers of America. Our unions represent workers in electric power, transportation, coal mining, construction, and other energy-related industries.

Our members' jobs and economic wellbeing will be affected by U.S. EPA's decisions on the proposed guidelines for reducing greenhouse gas emissions from existing fossil-fueled generating units. Our members are employed directly or indirectly at more than 500 coal- and gas-fueled generating units impacted by this rule. These comments identify the magnitude of potential jobs at risk as a consequence of the implementation of policies to decarbonize the utility sector by 2035.

These comments focus on the agency's methods for determining the Best System of Emission Reduction (BSER) for coal-fueled electric generating units in the four subcategories chosen by EPA; the imposition of new federally-enforceable retirement dates for the widely-disparate groups of units of differing ages, generation capacities, capacity factors, and other characteristics that would be covered by each subcategory; the lack of evidence supporting the choice of carbon capture and sequestration (CCS) as a technology that "has been adequately demonstrated" under the Clean Air Act; and the generation shifting that inevitably would result from implementation of the proposed guidelines. Such generation shifting was explicitly struck down in the Supreme Court's decision on the Clean Power Plan, *W. Va. et al. v EPA,* 142 S. Ct. 2587 (2022). We also are concerned that the proposed rule, due to its adverse impact on coal generation and widespread impacts on the composition of the electric generating fleet, may trigger the major question doctrine addressed in *West Virginia*.

We do not address the agency's proposals for requiring the use of green hydrogen in units firing natural gas, but defer to other expert commenters on the cost and feasibility of the agency's proposals, and whether green hydrogen "has been adequately demonstrated" for purposes of determining BSER for various categories of gas units. We note, however, that EPA's subcategorization of existing natural gas units differs markedly from its treatment of coal units. For existing natural gas units, EPA went "by the book" by subcategorizing based on unit type (steam vs. combined cycle), and capacity factor (e.g., <50%), without imposing federally-enforceable retirement dates.

Summary of Our Position

The proposed rule suffers from several legal and technical deficiencies sufficient to justify a reproposed rule. As discussed below:

- Section 111(b)(2) of the Clean Air Act (CAA or Act) does not authorize EPA to subcategorize electric generating units (EGUs) by retirement dates. Rather, section 111(b)(2) allows EPA to subcategorize by physical characteristics, specifically "classes, types, and sizes within categories" for the purpose of setting performance standards under CAA section 111. EPA historically has relied upon physical or operational characteristics for subcategorization. As a result, EPA does not have the authority under the Act to set different standards based on whether or not an affected coal-fired EGU will retire by a specific date (such as 2032, 2035, or 2040) or whether that unit may elect to limit its annual capacity factor to 20%.

- Many of the concerns raised by these comments - such as setting a Best System of Emission Reduction for groups of units with widely differing characteristics whose composition will not be known until well after the final rule is issued - could be addressed by using a different metric for subcategorization. EPA should consider using the age of units as the principal basis for subcategorization (e.g., pre-1960, 1960-75, 1976-1990 and post-1990). Further subcategorizing by factors such as megawatt capacity or capacity utilization may be appropriate. A

BSER for each subcategory could be assigned based on the characteristics of each group.

- We agree with the agency's decision to require routine maintenance and a unit-specific emission rate for units committing to retire before 2032, with no increase in CO2 emission rates; many of the units subject to this subcategory already have federally-enforceable retirement dates as a result of consent decrees or through other EPA regulations such as the Effluent Discharge rules. This subcategory should otherwise be restricted to units with short remaining useful lifetimes.

- We disagree with the proposed 20% capacity factor subcategory for units retiring between 2032 and 2035 because reduced utilization is often accompanied by generation shifting; we suggest that this subcategory be dropped while enlarging the natural gas cofiring category to cover units retiring between 2032 and 2039.

- We suggest reducing the natural gas cofiring rate from 40% to 20% for technical and economic reasons, while adding flexibility for states to develop in-state mass-based emission trading programs across all subcategories to improve the cost-effectiveness of the rule.

- We disagree that CCS "has been adequately demonstrated" at commercial scale electric generating units in the United States, and with the agency's reliance on *Portland Cement* - a New Source Performance Standard case - in a section 111(d) rulemaking for existing sources. We suggest broadening the array of emission control options available to sources planning to retire after 2040 and extending the compliance deadline from 2030 to 2035. EPA has provided a 2035 compliance date for existing natural gas combined cycle units employing 90% CCS controls. EPA acknowledges that coal sources subject to a 2030 deadline would not have time to wait for SIP approvals before having to finance, permit, and construct a CCS facility including all of its ancillary equipment including pipelines and underground storage capacity.

- As proposed, the rule would have profound impacts on the electric power sector and, in effect, redefine how electricity is generated and delivered through the electric power grid. Compliance with the proposed performance standards for fossil generation units will require the deployment of new, large-scale energy infrastructure that will take decades to develop and buildout. This restructuring of the power sector may trigger the major question doctrine and the clear statement rule applied in *West Virginia*. The proposed rule is similar to the aggressive transformation that EPA sought to advance in the Clean Power Plan

(CPP) by setting performance standards based on "building blocks" for efficient generation, increased use of natural gas in place of coal-fired generation, and generation shifting from fossil-fueled generation to renewable energy generation. Due to the stringency of these CPP performance standards, compliance could be achieved only by the reduced utilization or shutdown of existing coal-fired generation. The proposed rule accomplishes largely the same generation shifting objectives through different means.

Concerns with Subcategorization

Clean Air Act section 111(b)(2) (source subcategorization) does not authorize EPA to subcategorize affected electric generating units (EGUs) without knowing the characteristics of the facilities that would fall into the subcategory. Rather, section 111(b)(2) allows EPA to subcategorize the EGU source category by physical characteristics, specifically "classes, types, and sizes within categories" for the purpose of setting performance standards under CAA section 111.

As a result, EPA does not have the authority under the Act to establish unpopulated subcategories of affected coal-fired EGUs which would be populated only if a unit elected to retire by a specific date (such as 2032, 2035, or 2040). Rather than addressing unit retirement as a subcategorization issue in 111(b)(2), Congress told EPA in section 111(d) to allow the states to take "remaining useful life" into account in setting source-specific performance standards. The arbitrary retirement dates chosen by EPA may or may not correlate with the remaining useful life of particular sources included within each subcategory. These factors suggest the use of an age-based criterion as a more appropriate basis for subcategorization.[1]

EPA's proposed approach for subcategorization thus conflicts with the statute. In particular, it fails to differentiate among coal-fired units within the EGU source category in accordance with the statutory criteria, such as the size of the unit, the type of coal combusted, the boiler technology used for combusting the coal, other physical attributes of the generating facility, or how it is operated (such as the unit's capacity factor). Rather, EPA has lumped all classes, types, and sizes of coal-fired units together and then divided them into four proposed subcategories based on federally-enforceable

[1] EPA does not acknowledge that a state, using the authority given it to consider remaining useful life and other factors when setting standards for existing units, can alter the proposed deadlines for units to retire, based on its assessment of a range of relevant factors, including the remaining useful life of the unit. States can exercise their statutory discretion to alter any retirement subcategories for existing units EPA proposes or finalizes.

retirement dates. EPA then applied a presumptive Best System of Emission Reduction (BSER) to each subcategory - without knowing in advance any of the physical characteristics of units that may be included in each subcategory.

EPA will not know the number and composition of each existing coal-fired EGU subcategory at the time that EPA issues the final greenhouse gas power plant guidelines. The Agency will only be able to identify the coal-fired units falling within each of the four subcategories several years in the future when states adopt and submit to EPA their implementation plans that establish enforceable retirement dates and emission limitation requirements on the units within its jurisdiction. In short, EPA's BSER determinations were made "blind," without regard to any of the physical characteristics of units within each subcategory (e.g., age, boiler size and type, capacity factor, existing pollution controls, etc.)

EPA's Proposed Subcategories

EPA has proposed four subcategories for existing coal-fueled electric generating units, and assigned a BSER for each subcategory. The subcategories each have a federally-enforceable retirement date that units may opt-in to, or be assigned to if they already are subject to such a date. The resulting groups of units in each category will have widely disparate characteristics such as age, generating capacity, and the other physical characteristics that usually accompany subcategorization under section 111(b)(2).

EPA will not know the identities or characteristics of units in each subcategory until after State Implementation Plans (SIPs) have been submitted to the agency. All units in each subcategory must comply with their respective emission limitations by January 1, 2030. States must submit SIPs to EPA within two years following issuance of a final rule - meaning that sources without federally-enforceable retirement dates will need to decide their remaining operating lifetimes within the 2024-26 period. The four subcategories are:

1) Units that commit to retire before 2032 are subject to a unit-specific performance standard (lbs CO_2/MWh) based on routine O&M with no increase in their CO_2 emissions rate;

2) Units that commit to retire before 2035 and limit operation to a 20% capacity factor are subject to a performance standard based on routine O&M with no increase in their CO_2 emission rate;

3) Units that commit to retire before 2040 are subject to a performance

standard based on co-firing with 40% natural gas;

4) Units that retire 2040 or later are subject to a performance standard based on 90% CO_2 capture with CCS.

Comments on Subcategories

2032 Retirement Units

Units that commit to retire before 2032 with a federally enforceable retirement date are subject only to routine maintenance requirements with no increase in their allowable CO_2 emission rates. This subcategory is largely consistent with labor recommendations to EPA in 2022 regarding the treatment of units with relatively short remaining useful lifetimes. Labor did not, however, assign a federally enforceable retirement date to this or any other class of units.

Reduced Utilization with 2035 Retirement

EPA's proposed guidelines offer sources a 2035 retirement date if unit owners agree to limit their capacity to 20 percent through reduced utilization. The average capacity factor of coal units in 2021 was 49 percent per EPA,[2] with 67 percent of units being larger than 500 MW.[3]

The Supreme Court decision in *W.Va. et al. v EPA* rejecting the Clean Power Plan bars generation shifting as a means to reduce CO_2 emissions.[4] Notably, the Clean Power Plan identified reduced utilization and generation shifting as key means for sources to comply with the building blocks in that rule:

---

[2] 88 Fed. Reg. 33240, 33257.
[3] 88 Fed. Reg. 33240, 33258.
[4] *W. Va. et al. v. U.S. Environmental Protection Agency*, 142 S. Ct. 2587 (2022). The Court there noted: The Government attempts to downplay matters, noting that the Agency must limit the magnitude of generation shift it demands to a level that will not be "exorbitantly costly" or "threaten the reliability of the grid." Brief for Federal Respondents 42. This argument does not limit the breadth of EPA's claimed authority so much as reveal it: On EPA's view of Section 111(d), Congress implicitly tasked it, and it alone, with balancing the many vital considerations of national policy implicated in the basic regulation of how Americans get their energy. There is little reason to think Congress did so.

> EGUs have a long history of reducing their generation and either replacing it directly or having it replaced through the operation of the interconnected electricity system through measures similar to those in building blocks 2 and 3. Thus, an EGU can either directly replace its generation, or simply reduce its generation, and in the latter case, the integrated grid, combined with the high degree of planning and various reliability safeguards, will result in entities providing replacement generation. This means that consumers receive exactly the same amount of the same product, electricity, after the reduced generation that they received before it. 80 Fed. Reg. 64662, 64782 (October 23, 2015).

It thus appears that the proposed carbon guidelines are inviting just the sort of generation shifting that the Court rejected in *W.Va. v. EPA*. There is no certainty that the aggressive deployment of renewable generation forecast by EPA will materialize in the 2032-2035 timeframe, and reliability considerations may dictate substantially larger utilization for units in this subcategory. Providing states with flexibility to change capacity factor limits may not be exercised in a timely manner sufficient to avoid serious reliability issues.

We suggest an alternative of dropping the 2035 reduced utilization category and moving forward the natural gas cofiring category. The cofiring subcategory should be modified to reduce the nominal gas cofiring rate to 20% as explained below, to cover units committing to retire after 2032 and before 2040, with compliance by 1/1/2030.

Natural Gas Cofiring

EPA's proposed third subcategory covers units that commit to retire before 2040 that will be subject to a performance standard commencing January 1, 2030, based on 40% cofiring of natural gas. We regard this level of cofiring as excessive both in terms of the cost of natural gas and technical constraints associated with combusting such a large volume of gas in a conventional coal-fueled boiler.

Kim *et al.*[5] analyzed the impacts of different levels of natural gas cofiring on a large coal fired boiler. Their analysis examined various gas injection points, boiler heights, and gas cofiring mixes. Their research concluded that a 20% gas cofiring rate was optimal, and avoided damage to boiler tubes due to higher flue gas exit temperatures (FEGT) associated with higher gas cofiring rates such as 30% or 40%:

---

[5] *See*, Kim, *et al.*, *Methane Gas Cofiring Effects on Combustion and NO_x Emission in 550 MW Tangentially Fired Pulverized-Coal Boiler*, ACS Omega. 2021 Nov 23; 6(46): 31132–31146. Published online 2021 Nov 15.

> The NOx reduction is logarithmically proportional to the methane cofiring rate. That is, at a cofiring rate of 40%, compared to the base case, NOx emissions are reduced by 69.8% due to reduced fuel-N caused by substituted methane and the reburning mechanism. ...
> Despite these advantages of increasing methane cofiring, the 20% methane cofiring rate with a NOx reduction of 57.3% was found to have the best performance owing to the designed FEGT value. Thus, high FEGT at 30% or a higher methane cofiring rate might damage the tube material.[6]

We recommend that EPA consider broadening the time horizon for units in this category to cover the period after 2032 and before 2040 while reducing the nominal gas cofiring rate to 20%. Resources for the Future (RFF) chose this level of cofiring in its 2021 analysis of the costs and emission reductions associated with gas cofiring, including various emission trading approaches:

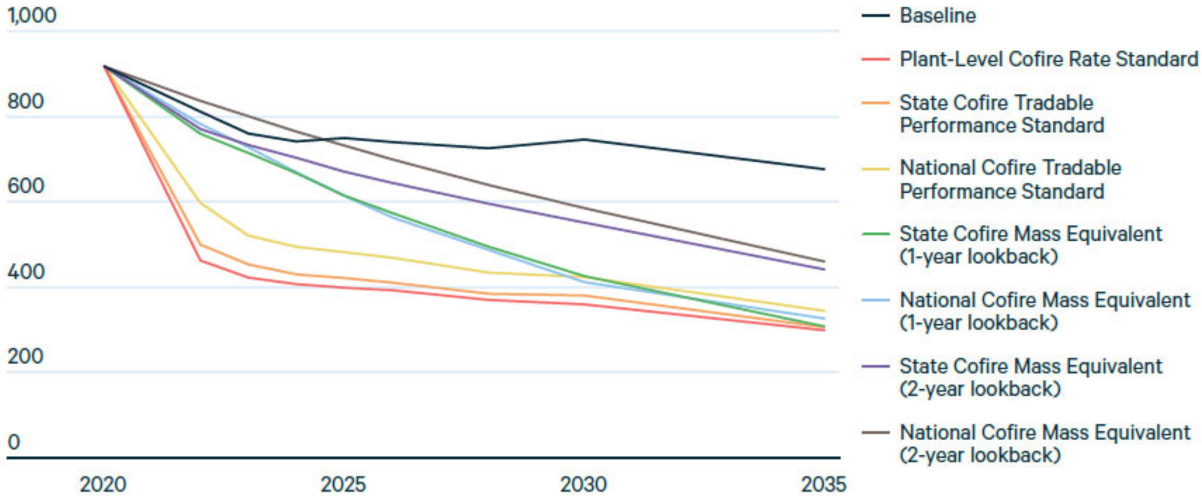
> We describe a performance standard, based on the opportunity to cofire with natural gas at coal EGUs, that would address most of the concerns that have been raised before the courts. Natural gas cofiring is already a demonstrated and widespread practice. Because a performance standard based on the opportunity for cofiring applies to an individual facility, it does not raise concerns about measures taken outside regulated emissions sources. ... Importantly, it would provide a soft landing for coal units that choose to phase out production and reduce emissions at units that continue to operate.
>
> We model a natural gas cofiring standard using RFF's Haiku electricity market model, including gas price forecasts from Annual Energy Outlook 2019, and site specific estimates of the capital cost to expand gas delivery provided by Natural Resources Defense Council.[7]

RFF evaluated several different trading options along with a plant-based 20% performance based standard. As shown in the chart below, the plant-based standard achieves the largest emission reductions:

---

[6] *Id.*, at M.
[7] Resources for the Future, *Reducing Coal Plant Emissions by Cofiring with Natural Gas*, Issue Brief 21-04 (May 2021) at 2.

Figure 1. CO_2 Emissions at Coal Plants under 20% Cofiring With No Other Regulation (million tons)



A cofiring regulation could take three forms. The first form is a plant-specific rate-based standard requiring every plant to reduce its emissions rate to the rate prescribed by the standard. To comply, a coal plant could cofire with natural gas or install another technology to reach that emissions rate. The second form is a tradable performance standard that enables a group of coal plants to achieve an average emissions rate equivalent to the standard. In this case, some plants could overcomply by cofiring more than the regulation requires while other plants undercomply. A tradable performance standard could be applied at the state level, or states could be permitted to opt into a national-level tradable performance standard. The third form is a mass-based standard, which requires that total emissions from a group of coal plants not exceed an emissions budget based on the performance standard's emissions rate and historical generation. … We model a mass-based standard that multiplies generation levels (in MWh) in a previous year by the emissions rate standard (tons/MWh) to arrive at a budget (tons). We describe a one-year and two-year look back at previous generation levels and update the emissions limit each year. The time profile of emissions from coal plants over 15 years is illustrated in Figure 1 for a 20 percent cofiring standard under the three forms of regulation. For a baseline in Figure 1, we assume no other regulations beyond those in effect at the end of 2020, and other parameters, such as demand and natural gas prices, match Annual Energy Outlook 2019 forecasts. The cofiring standard is assumed to take effect in 2022.

The plant-specific rate-based standard, which is the least flexible approach, achieves the greatest emissions reductions, as illustrated by the bottom curve in the figure. Increased flexibility provided by a tradable performance standard

> at the state or national level leads to somewhat greater emissions. A mass-based standard at the state and national level falls farther up the continuum of flexibility and results in yet fewer emissions reductions. Figure 1 demonstrates that all forms of the cofiring regulation reduce emissions from coal plants, and the least flexible policies reduce coal emissions the most. Consequently, EPA may want to consider the method of implementation allowed for states in determining the stringency of the standard.[8]

EPA has not proposed a trading program in this proposed rule, but is taking comment on alternative trading approaches. We support giving states the option to develop an in-state trading program along the lines described by RFF. Trading can encourage more cost-effective compliance strategies, as proven with experience under the Title IV SO2 trading program and Title I NOx trading programs.

Subcategory 4: CCS Retrofits

The fourth subcategory requires CCS with 90% removal to be installed on units not included in other subcategories by January 1, 2030, with a retirement horizon of 2040 or later. Units without federally enforceable retirement dates that do not opt in to one of the three other retirement subcategories are assigned to the post-2040 subcategory with its 90% CCS retrofit requirement by January 1, 2030. This requirement itself is objectionable because these units likely differ widely in age, size, capacity factor, access to suitable CO2 storage capacity, and the technical and economic feasibility of retrofitting CCS. These units - along with other units choosing to opt-in to the other three subcategories - are deprived of a BSER analysis appropriate for their individual characteristics. There also are issues, addressed by other commenters, about the feasibility of the proposed 90% reduction requirement.

EPA recognizes that there is no commercial scale electric generating unit in the United States currently operating with CCS technology and deep underground storage, while denying that the absence of commercial scale U.S. CCS applications is relevant to its BSER determination.[9] While our unions have long supported the demonstration and development of CCS due to its superior carbon removal potential and potential for large-scale job creation, we do not believe that the technology currently meets the statutory requirement of Section 111(a) for technology that "has been adequately demonstrated."

[8] *Id.*, at 2-3.
[9] *See,* 88 Fed. Reg. 33272

We also object to EPA's reliance on *Portland Cement v. Ruckelshaus* , a New Source Performance Standard case that allows EPA to look forward to technologies that "may fairly be projected for the regulated future,[10] subject to "the restraints of reasonableness," without "crystal ball speculation," and dependent on a showing of "achievability."[11] Regardless of the exact details of the showing required by this language,[12] this is an existing source rulemaking under section 111(d) to which the forward-looking NSPS holdings of *Portland Cement* and related cases are inapplicable. EPA acknowledged in the Clean Power Plan that courts had not ruled on the application of *Portland Cement* in section 111(d) cases, but recognized that the extensive case law in section 111(b) cases involves new (not existing) sources.[13]

Congress has actively supported CCS research and demonstration for many years, mainly through programs administered by the Department of Energy. The recent review of CCS programs by the Congressional Research Service summarizes this history and shows current legislative appropriations for CCS demonstration projects well into the future:

> DOE has funded R&D of aspects of the three main steps of an integrated CCS system since at least 1997, primarily through its Fossil Energy and Carbon Management Research, Development, Demonstration, and Deployment program (FECM). CCS-focused R&D has come to dominate the coal program area within DOE FECM since 2010. Since FY2010, Congress has provided $9.2 billion (in constant 2022 dollars) total in annual appropriations for FECM ... The Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58) provided $8.5 billion (nominal dollars) in supplemental funding for CCS for FY2022-FY2026 (see table below), including funding for the construction of new carbon capture facilities and commercial carbon storage facilities.[14]

---

[10] *Id.* Quote is from *Lignite Energy Council,* 198 F.3d at 934 (citing *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973)).
[11] *Portland Cement,* 486 F.2d at 391.
[12] *Compare West Virginia v. EPA*, 142 S.Ct. at 2629 (Kagan dissenting) ("[H]as been adequately demonstrated…imposes meaningful constraints" including that the "best system has a "proven track record.").
[13] 80 Fed. Reg. 64662, 64719. "In addition, although the D.C. Circuit has never reviewed a section 111(d) rulemaking, the Court has reviewed section 111(b) rulemakings on numerous occasions during the past 40 years, handing down decisions dated from 1973 to 2011."
[14] Congressional Research Service, *Carbon Capture and Sequestration (CCS) in the United States* (October 5, 2022) at 22-23. Footnotes omitted.

Infrastructure Investment and Jobs Act Supplemental Appropriations for Carbon Capture and Storage Programs

FY2022 through FY2026 (in thousands of nominal dollars)

Program	FY2022	FY2023	FY2024	FY2025	FY2026	Total FY2022-FY2026
Front-End Engineering and Design (carbon capture)	20,000	20,000	20,000	20,000	20,000	100,000
Carbon Capture Large-Scale Pilot Projects	387,000	200,000	200,000	150,000	—	937,000
Carbon Capture Demonstration Projects	937,000	500,000	500,000	600,000	—	2,537,000
Carbon Dioxide Transportation Infrastructure Finance and Innovation (CIFIA)	3,000	2,097,000	—	—	—	2,100,000
Carbon Utilization	41,000	65,250	66,563	67,941	69,388	310,141
Carbon Storage Validation and Testing	500,000	500,000	500,000	500,000	500,000	2,500,000

Source: Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58), Division J.

Congress's authorization of some $2.5 billion for CCS demonstration projects to be spent over the period FY2022 to FY2025 clearly illustrates the fact that CCS has not been "adequately demonstrated" for purposes of this section 111(d) rulemaking. Even with a 2030 prospective compliance date, sources in the 2040 subcategory would need to begin preparations for a major CCS retrofit project - engineering, financing, permitting and related activities - as soon as possible following a final rulemaking. Final SIP approvals may not be available before 2026-27. EPA provided a 2035 compliance date for existing natural gas combined cycle units employing 90% CCS controls. The same date should apply to coal CCS projects.

Generation Shifting through Premature Retirement

On July 7, 2023, EPA released updated IPM modeling for the proposed rule taking into account higher projected LNG and natural gas prices.[15] The updated modeling underscores the extent of premature coal retirements projected under the proposed rule:

> Under the integrated proposal modeling, 44 GW of coal-fired EGUs have committed retirements by 2035 and operate at an annual capacity factor of 20 percent or less in 2030, and as such are subject to the near-term existing coal-fired steam generating units subcategory. By 2040, 1 GW of coal-fired EGU capacity has committed to retirement and is subject to the 40 percent natural gas co-firing requirement. 12 GW of coal-fired EGUs that plan to operate past 2040 are subject to the long-term existing coal-fired steam generating unit subcategory and, as such, install CCS (reflecting 3 GW incremental to the updated baseline). Finally, 21 GW of coal-fired EGUs undertake coal to gas conversion (9 GW incremental to the updated baseline).
> Under the updated baseline, total coal retirements between 2023 and 2035 are projected to be 104 GW (or 15 GW annually). Under the proposed rules, total coal retirements between 2023 and 2035 are projected to be 126 GW (or 18 GW annually). This is in comparison to an average historical retirement rate of 11 GW per year from 2015 – 2020.[16]

The accelerated pace of retirements under the proposed rule will result in generation shifting from coal to other energy sources. In the absence of the rule, premature retirements and the associated loss of generation could be made up by compensating generation from other coal sources. This would not be possible under the proposed rule due to the emission caps and other limitations imposed by each of the four subcategories. In other words, every Gigawatt of coal capacity that is shuttered before the date it otherwise would be expected to cease operations will result in a corresponding increase in non-coal generation through generation shifting.

---

[15] EPA, "INTEGRATED PROPOSAL MODELING AND UPDATED BASELINE ANALYSIS," Memo to the Docket, July 7, 2023.
[16] *Id.*, at 16.

An Alternative Approach to Subcategorization

Many of the concerns raised by these comments - such as setting a Best System of Emission Reduction for groups of units with widely differing characteristics whose composition will not be known until well after the final rule is issued - could be addressed by using a different metric for subcategorization. EPA should consider using the age of units as the principal basis for subcategorization (e.g., pre-1960, 1960-75, 1976-1990 and post-1990). Further subcategorizing by factors such as megawatt capacity or capacity utilization may be appropriate. A BSER for each subcategory could be assigned based on the characteristics of each subgroup.

Potential Magnitude of Job Losses

The agency's consideration of proposals that risk the elimination of fossil-based electricity needs to focus on the impacts of direct and indirect job losses on families and communities. Many power plants, coal mines and other fossil energy facilities are located in rural areas, and often are the largest employers and sources of tax revenues for local communities. Indirect jobs in the community are supported through the relatively high wages paid to fossil energy workers, and by the large supply chains needed to support energy facility operations and maintenance. Power plant workers, coal miners, natural gas pipeline workers and coal-dependent railroad employees typically are 50 to 60 years old, often with few prospects for reemployment at comparable wages.

EPA has estimated that the proposed rule may result in a net loss of 25,000 recurring job-years.[17] We believe that net job loss estimates obscure the magnitude of direct job losses at power plants, coal mines, railroads, and other affected energy facilities. Our estimates of the potential direct jobs at risk with a 2035 electric utility decarbonization program (see table below) are based on 2019 U.S. Bureau of Labor Statistics direct employment and wage data for the coal, rail, utility and natural gas sectors. Estimated benefits are from the U.S. Department of Labor. The number of direct jobs at risk for industries such as rail and natural gas are adjusted for partial job dislocation (e.g., one-third of natural gas production and transmission jobs are included based on the electric utility share of total gas production.)

[17] EPA Regulatory Impact Analysis at 5-17.

Estimates of Direct Energy Jobs at Risk with 2035 Utility Decarbonization

Sector	Direct Jobs*	Direct Jobs Avg. Wage*	Estimated Avg. Benefits**	Total Wages and Benefits per Direct Job
Fossil Elec. Gen.	89,600	$85,468	$25,640	$111,108
Coal Mining	50,770	$89,180	$26,745	$115,925
Nat. Gas Prod. & Trans.	103,400	$90,300	$27,090	$117,390
Railroads	29,900	$67,240	$20,172	$87,412
Totals/Avg	273,670	$85,990	$25,797	$111,787

*Direct jobs and average wages for 2019 from U.S. Bureau of Labor Statistics.
** Average benefits estimated at 30% of direct wages per U.S. Department of Labor estimates (2019).

These estimates do not consider the potential loss of an estimated 1.1 million indirect jobs[18] associated with the coal, rail, gas and utility direct jobs at risk, or the programs and policies needed for job retraining, community economic development, educational assistance, targeted infrastructure development, and incentives for industrial development in adversely impacted area. We assume that these and similar programs will be funded through federal and state appropriations beyond those already authorized by Congress.

Conclusion

We appreciate the opportunity to comment on the proposed carbon emission guidelines for fossil-fueled power plants. We will appreciate your consideration of these comments.

---

[18] Estimates of indirect jobs at risk per industry are based on job multipliers from the Economic Policy Institute, *Updated employment multipliers for the U.S. economy* (January 23, 2019). For a more detailed analysis of the potential direct and indirect job losses associated with a 2035 decarbonization target see, Potential Fossil Energy Job Losses and Transition Needs Final 101920, available at ujep4jobs.org).

Contact information for our individual unions appears below:

International Brotherhood of Boilermakers,
Iron Ship Builders, Blacksmiths, Forgers and Helpers
1750 New York Avenue, NW, Suite 335
Washington, DC 20006
Contact: Cecile Conroy
email: cconroy@boilermakers.org

International Brotherhood of Electrical Workers
900 7th Street, NW
Washington, DC 20001
Contact: Donnie Colston
email: donnie_colston@ibew.org

International Association of Bridge, Structural, Ornamental,
and Reinforcing Iron Workers
1750 New York Avenue NW - Suite 400
Washington, DC 20006
Contact: Ross Templeton
email: rtempleton@iwintl.org

Transportation · Communications Union, IAM
3 Research Place
Rockville, MD 20850
Contact: David Arouca
email: aroucad@tcunion.org

United Mine Workers of America
18354 Quantico Gateway Drive
Triangle, VA 22172
Contact: Phil Smith
email: psmith@umwa.org