MEMORANDUM

Date: September 11, 2026

To: EPA Docket No. EPA-HQ-OAR-2025-0124

Subject: Economic Impact Analysis for the Supplemental Proposed Rule, Rescission of the Greenhouse Gas Findings for Fossil Fuel-Fired Power Plants and Repeal of Regulations for Power Plant Greenhouse Gas Emissions Under Clean Air Act Section 111

1 INTRODUCTION

In this action, the U.S. Environmental Protection Agency (EPA) is supplementing its proposal to repeal all greenhouse gas (GHG) emission standards for fossil fuel-fired electric generating units (EGUs) to effectuate the best reading of Clean Air Act (CAA) section 111. We propose that CAA section 111 does not authorize the EPA to regulate emissions from power plants in response to global climate change concerns. For the multiple and independent reasons described in the preamble, this additional rationale would also require rescinding the Administrator's contrary findings and determinations in 2015 and repealing all associated 2015 and 2024 GHG standards for the fossil fuel-fired EGU source category. In a separate action published concurrently with this supplemental notice, the EPA is finalizing the repeal of certain 2024 GHG standards for the fossil fuel-fired EGU source category on distinct legal and technical grounds.

In accordance with Executive Orders (E.O.) 12866 and 13563, the guidelines of OMB Circular A-4, and *EPA's Guidelines for Preparing Economic Analyses*, this Economic Impact Analysis (EIA) analyzes the regulatory compliance costs and benefits associated with this supplemental proposal.[1]

The "baseline" in this analysis is a business-as-usual scenario that represents the behavior of the regulated sector under market and regulatory conditions in the absence of this action. This analysis builds upon modeling conducted for the *Regulatory Impact Analysis for the Final*

[1] U.S. EPA. (2024). *Guidelines for Preparing Economic Analyses (3rd edition)*. EPA-240-R-24-001. Washington, DC. https://www.epa.gov/system/files/documents/2024-12/guidelines-for-preparing-economic-analyses_final_508-compliant_compressed.pdf.

Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units and is based upon the EPA's Integrated Planning Model (IPM) 2025 Reference Case power sector projections; see Section 2.1 for a description of the methodology and how the analysis of this EIA relates to analysis in the RIA for the Final Partial CPS Repeal.[2] The analysis of this action assumes that the majority of the 2024 Carbon Pollution Standards (CPS) for the power sector have already been repealed in a separate final action. However, the Phase 1 requirements of the New Source Performance Standards (NSPS) of the 2024 CPS remain in place in this baseline.[3] The baseline also includes the 2015 NSPS that includes standards of performance for GHG emissions from steam generating units and IGCC facilities, and standards of performance for GHG emissions from stationary combustion turbines.[4]

As stated above, in this action, the EPA proposes to repeal all GHG emission standards for fossil fuel-fired EGUs under section 111 of the CAA, which includes repealing the 2015 NSPS and Phase 1 of the 2024 CPS. In this economic analysis, we quantitatively assess the removal of these standards in the "proposed repeal" scenario. Based on the results of the modeling conducted for the Final Partial CPS Repeal RIA, in this analysis we assume that the Phase 1 standards from the 2024 CPS are the greenhouse gas standards for the power sector with the most binding requirements to model, and so we quantitatively assess their removal in the proposed repeal scenario. Based on that same modeling, this proposed repeal scenario is also reflective of repealing the 2015 NSPS requirements, as we assume that those requirements would be less binding than the Phase 1 requirements, as described in Section 2.1.2. However, while the EPA has not projected the construction of any new steam generating units in this analysis, we are aware that there are companies that are pursuing new coal-fired generation that is not reflected in the modeling. To the extent that any of those projects do not include carbon capture and storage (CCS) achieving emission limitations consistent with the 2015 NSPS standards that would be revoked as part of this proposal, this proposal would result in a cost savings for those units, as they would no longer be obligated to install partial CCS.

[2] U.S. EPA. (2025). *Incremental Documentation for EPA 2025 Reference Case*. Washington, DC. https://www.epa.gov/power-sector-modeling/documentation-2025-reference-case.
[3] The 2024 CPS Phase 1 standards require highly efficient generation for base load and intermediate load combustion turbines, and the use of lower-emitting fuels for low load turbines.
[4] The 2015 NSPS standards require highly efficient generation for base load turbines and the use of clean fuels for non-base load turbines, and partial carbon capture and storage (CCS) for steam generating units.

This EIA includes estimates based on one strategy for complying with the assigned Phase 1 NSPS requirements. This analysis assumes that a small proportion of affected sources would comply with Phase 1 of the NSPS by building more new simple cycle combustion turbine capacity than would otherwise be needed to stay below the 40 percent capacity factor threshold and avoid being subject to the base load standard (*i.e.*, those based on highly efficient combined cycle generation). We estimate that this modeled compliance approach with Phase 1 NSPS would increase capital costs and fixed operations and maintenance (O&M) costs, but would cause no change in generation, emissions, nor variable O&M costs. Under the proposed repeal analysis where we remove this Phase 1 NSPS constraint, we project some cost savings and no associated change in generation or emissions.

Stakeholders have expressed that the Phase 1 limits are burdensome and costly. In this analysis, we project small system-wide cost savings relative to the cost impacts of many other EPA power sector rules because we anticipate that the Phase 1 limits for new combustion turbines would only affect a small amount of capacity. While this is greater than what was estimated in 2024, we recognize a number of stakeholders have stated that the impacts of the Phase 1 standards could be much more significant. If, as some stakeholders have provided, more new units would have to limit operation because of the Phase 1 standards, this rule would have greater cost savings than initially estimated. Additionally, compliance pathways that differ from those assumed in this analysis could result in changes to emissions and cost estimates. For further discussion *see* Section 2.2.

The EPA solicits comments on the impacts of removing the 2015 NSPS and Phase 1 of the 2024 CPS (see comment solicitation C-6 in section VII of the preamble.

The remainder of this EIA contains the impacts analysis and a discussion of the uncertainties and limitations of this analysis, including but not limited to discussion related to EPA's IPM 2025 Reference Case power sector projections that were used as a starting point for the impacts analysis conducted outside of IPM that follows. Throughout this analysis, costs are presented as positive values, and cost savings are presented as negative values. We present the present value (PV) and equivalent annual value (EAV) estimates of changes in cost, calculated for the years 2026 to 2047, discounted to 2025 using 3 and 7 percent discount rates. In addition, we present the assessment for specific snapshot years, consistent with historical practice. These snapshot years are 2030, 2035, 2040 and 2045.

2 IMPACTS ANALYSIS

This section describes the analysis methodology and provides the estimated impacts of the proposed action on compliance costs, emissions, fuel use, and small entities.[5]

2.1 Methodology

This analysis builds upon modeling conducted for the *Regulatory Impact Analysis for the Final Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units*. The analysis presented in this EIA is based upon the EPA's Integrated Planning Model (IPM) 2025 Reference Case power sector projections.[6] The 2025 Reference Case did not incorporate any of the 2024 CPS requirements, and therefore can be used to represent the *policy scenario* for this action in which the 2024 CPS standards have been fully repealed. Below, we discuss how we adjusted the 2025 Reference Case to construct a baseline scenario that includes compliance with the 2024 CPS Phase 1 requirements and 2015 NSPS requirements.

In this action, in addition to repealing the 2024 CPS Phase 1 requirements, we are also repealing the 2015 NSPS requirements for fossil fuel-fired steam generating units and stationary combustion turbines. The following subsections describe the EPA's approach to quantifying estimated avoided compliance costs in the power sector associated with repealing each set of standards in this action, which combines estimates projected directly by the model with costs estimated outside the model framework.

2.1.1 Repealing 2024 CPS Phase 1 Standards

Phase 1 of the NSPS under the 2024 CPS strengthened requirements for new stationary combustion turbines. In particular, base load combustion turbines rated at over 2,000 MMBtu/h and maintaining an annual average capacity factor of above 40 percent would have to achieve an emission rate of 800 lbs CO_2/MWh, base load combustion turbines rated at below 2,000

[5] The EPA uses size standards established by the U.S. Small Business Administration to determine whether entities are considered small for purposes of this analysis. For more information, please see: See U.S. SBA Office of Advocacy. (2017). *A Guide For Government Agencies: How To Comply With The Regulatory Flexibility Act*. Available at: https://advocacy.sba.gov/wp-content/uploads/2019/06/How-to-Comply-with-the-RFA.pdf.
[6] U.S. EPA. (2025). *Incremental Documentation for EPA 2025 Reference Case*. Washington, DC. https://www.epa.gov/power-sector-modeling/documentation-2025-reference-case

MMBtu/h and maintaining an annual average capacity factor of above 40 percent would have to achieve an emission rate of 800 – 900 lbs CO_2/MWh (consistent with operation of highly efficient combined cycle generation). Combustion turbines operating at intermediate load (i.e., annual capacity factor of greater than 20 and less than or equal to 40 percent) would have to maintain an emission rate of 1,170 lbs CO_2/MWh (consistent with operation of highly efficient simple cycle generation). Combustion turbines operating at low load (maintaining annual average capacity factor of less than or equal to 20 percent) would have to use lower emitting fuels, i.e., those with a less than 160 lbs CO_2/MMBtu content.

As described earlier, EPA's analysis adopts assumptions regarding heat rates for new combined cycles and new simple cycle combustion turbines from the EIA's Annual Energy Outlook 2025. These assumptions result in an assumed combined cycle heat rate of 6,226 Btu/kWh and an assumed new combustion turbine heat rate of 9,142 Btu/kWh. EPA's assumed pollutant content for natural gas is 117 lbs CO_2/MMBtu, meaning that the emission rate for a new combined cycle addition in EPA's analysis is about 730 lbs CO_2/MWh, while the emission rate for a new simple cycle combustion turbine is about 1,070 lbs CO_2/MWh. Based on this set of assumptions, both combined cycle builds and simple cycle combustion turbine builds operating below 40 percent capacity factor in EPA's analysis are compliant with the Phase 1 standards. However, simple cycle combustion turbines operating at greater than 40 percent capacity factor (*i.e.*, base load capacity) in EPA's analysis would not be compliant with the Phase 1 requirements for these units.

The portion of simple cycle combustion turbines operating at greater than 40 percent capacity factor (*i.e.*, base load capacity), which would not be compliant under EPA's projections, are a small amount of the total combustion turbine buildout in the modeled results. Under the 2025 Reference Case, in 2030, about 0.44 GW out of a total of 42 GW of projected new combustion turbine additions are projected to operate at base load levels (averaging 45 percent capacity factor). In 2035, about 1 GW out of a total 42 GW of projected new combustion turbine capacity are projected to operate at baseload levels (averaging 50 percent capacity factor). New combustion turbines are not projected to operate at baseload levels thereafter.

One way to comply with the Phase 1 standards while also meeting energy and peak demand is to increase the size (capacity) of the new combustion turbines that are projected to operate above 40 percent. In other words, if a combustion turbine of 100 MW was operating at a 50 percent capacity factor it would produce 438 GWh of electricity over the course of the year and not be compliant with the Phase 1 standards. If that turbine was instead 125 MW and operated at 40 percent capacity factor, it would still produce the same amount of emissions and the same amount of generation but also be compliant with the Phase 1 standards.

In Section 2.3.2, we present this calculation, along with the incremental fixed operations and maintenance (FOM) and capital costs necessary to build and maintain this greater capacity of combustion turbines. Since generation does not change, we assume no change in fuel costs, variable operations and maintenance (VOM), or emissions under this approach. For the additions that exceed the base load threshold, we calculate the average capacity factor, and then use this value to calculate the effective increase in capacity required for the simple cycles to remain below base load levels on average. The incremental FOM and capital costs for these additions is then calculated. While this calculation is performed outside of the model, imposing the policy constraint within the cost-minimizing modeling framework would result in equal or lower costs.[7]

2.1.2 Repealing 2015 NSPS

The 2015 NSPS established standards of performance for fossil fuel-fired steam generating units and stationary combustion turbines. For any new fossil fuel-fired steam generating unit, it requires CCS in order to meet an emissions rate of 1,400 lbs CO_2/MWh. EPA's 2025 Reference Case does not project any new coal additions, and therefore this analysis does not reflect any costs or benefits of repealing this standard. However, the EPA acknowledges that new coal additions could potentially occur under certain circumstances. Whether this rule would impact those units depends on the specifications of the ultimate projects and whether the projects include CCS. There could be coal projects under development that are not contemplating CCS and this rule would clearly lower cost for those units. Considering these factors, the EPA is

[7] To make this concrete, suppose a cost-minimizing model has only two compliance strategies available to satisfy a policy constraint, A and B. If Strategy A costs \$X within the modeling framework, then \$X is an upper bound on modeled compliance cost. The model chooses the cheaper option: if B costs less than A, the model chooses B and compliance cost is less than \$X; if not, the model chooses A and compliance cost is \$X.

not assessing the cost savings of repeal of the 2015 NSPS requirements for fossil fuel-fired steam generating units for these projects.

Regarding turbines, the 2015 NSPS subcategorizes natural gas-fired combustion turbines by base load (greater than an approximately 40 percent capacity factor) and non-base load units (less than or equal to an approximately 40 percent capacity factor).[8] The 2015 NSPS requires that natural gas-fired combustion turbines operating as base load units use natural gas combined cycle technology to meet an emission standard of 1,000 lbs CO_2/MWh. The 2015 NSPS does not include an output-based standard for non-base load units, instead requiring a heat input based standard consistent with combustion of uniform fuels.[9] These standards currently apply to turbines that commenced construction after January 8, 2014, but on or before May 23, 2023. Since 2015, the U.S. power sector has added about 62 GW of new natural gas combined cycle and 17 GW of new natural gas combustion turbines. This capacity is currently in compliance with the 2015 NSPS standards, and it is reasonable to assume that this capacity would continue to operate at current emissions levels in the absence of the 2015 NSPS standards. Therefore, this analysis does not reflect cost savings related to the repeal of the 2015 NSPS standards for existing units subject to those standards. For units projected to be constructed in future years, the 2015 NSPS standards are less stringent than the 2024 CPS Phase 1 standards discussed above. Therefore, this analysis does not estimate incremental power sector generating cost savings beyond the cost savings associated with the repeal of the 2024 CPS Phase 1 standards discussed above. This analysis does estimate the monitoring, reporting, and recordkeeping (MR&R) cost savings to industry associated with repealing the 2015 NSPS, as shown in Section 2.3.1.

2.1.3 Relation to Analysis in the RIA for the Final Partial CPS Repeal

While the final partial CPS repeal action does not repeal Phase 1 of the 2024 NSPS nor the 2015 NSPS, the modeling included as part of the RIA for that rulemaking assumed repeal of all requirements under the 2024 CPS. As described in Section 3.2 of the RIA for that rulemaking, the EPA estimated that the inclusion of the repeal of the Phase 1 standards would not result in a

[8] In the 2015 NSPS, the threshold between non-base load and base load natural gas-fired units is based on the design efficiency of the combustion turbine, or 50 percent, whichever is lower. Combustion turbines firing less than 90 percent natural gas were subject to a heat-input based standard (effectively, less than 160 lbs CO_2/MMBtu).
[9] Effectively, a fuel (*e.g.*, natural gas) with a heat input-based emission rate of 120 lbs CO_2/MMBtu or less.

meaningful change to the modeled cost and emissions outcomes.[10] As shown in Section 2.3.2 of this analysis, we estimate the EAV of cost savings of repealing the Phase 1 standards to be approximately $23 million under a 3 percent discount rate. This would not substantially change the results of the analysis in the RIA, which estimated the EAV of cost savings to be $10 billion for the Final Partial Repeal of the Carbon Pollution Standards. As stated earlier, the EPA solicits comments on the impacts of removing the 2015 NSPS and Phase 1 of the 2024 CPS.

2.2 Limitations and Uncertainties

The EPA's modeling is based on market research and expert judgment of various input assumptions for variables whose outcomes are uncertain. As a general matter, the Agency reviews the best available information from engineering studies of air pollution controls and new capacity construction costs to support a reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory actions for EGUs. The annualized cost of the rules for EGUs, as quantified here, is the EPA's best assessment of the cost of implementing the rules for the power sector. These costs are generated from rigorous economic modeling of anticipated changes in the power sector due to implementation of the rule.

There are several key areas of uncertainty related to the analysis that are worth noting, including:

- The analysis assumes one method of compliance – i.e., that owners and operators chose to increase the size of their combustion turbine additions in order to meet the Phase 1 NSPS requirements. However, it is possible that some other combination of options could be selected, for instance shifting builds from simple cycle additions to combined cycles, building incremental renewables and/or storage, and/or delaying retirement at existing facilities. These alternative compliance pathways could result in changes to emissions and cost estimates.
- The efficiency assumptions for new turbine additions underpinning the analysis are taken from EIA's AEO 2025. However, stakeholders have suggested that efficiency of new turbines could be lower and could vary depending on operational choices. As such, the impact of this action could be different from that represented by this

[10] *Regulatory Impact Analysis for the Final Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units.* Available in Docket ID EPA-HQ-OAR-2025-0124.

analysis. To the extent that turbines are less efficient, more turbines would have had challenges meeting the standards, therefore the repeal of those standards would result in greater cost savings.

- The EPA is aware that a number of stakeholders have stated that the impacts of the Phase 1 standards could be more significant than EPA estimates in this analysis. If as some stakeholders have stated, implementation of the Phase 1 standards would have required more new units to limit operation, this rule would have a greater cost savings.
- In this analysis, we do not project any economic additions of new coal-fired steam generation. However, industry could choose to build coal-fired power in order to satisfy other goals. While the EPA has not projected the construction of any new coal-fired units in this analysis, we are aware that there are companies that are pursuing new coal-fired generation. To the extent that any of those projects do not include carbon capture and storage achieving emission limitations consistent with the NSPS standards that would be revoked as part of this proposal, this proposal would result in a cost savings for those units, as they would no longer be obligated to install partial CCS.
- IPM was developed almost three decades ago to analyze the power sector as it existed at the time. Since IPM was developed, the electricity sector has changed in fundamental ways. Stakeholders consistently raise that the power sector is dynamic and increasingly complex, and that the EPA should adjust our analytical approach to rely on models and/or tools that are transparent and adaptable. Alternative models exist that are potentially better suited to the analytical questions that will be most important to future regulatory analyses. Different models may be more or less appropriate depending on the nature of the analysis, and it is important that the EPA has access to a variety of analytical tools to best tailor our approach. Further, IPM is a proprietary model and the code base is not available to the general public. Regulatory analyses conducted using proprietary models lack transparency and hinder the ability of the public to engage with and reproduce our analytical findings. Models and tools developed and used by stakeholders, including states and private institutions, may more fully represent the power sector, be more

transparent, and/or be more appropriate for the EPA to use in regulatory analyses. The EPA has a responsibility to use the best available tools to inform the public of the likely impacts of our regulatory actions. Pursuant to E.O. 14303 ("Restoring Gold Standard Science"), and in an effort to ensure that "Federal decisions are informed by the most credible, reliable, and impartial scientific evidence available," the EPA is currently exploring several open-source power sector modeling alternatives and plans to replace the Agency's current power sector model (i.e., IPM) for power sector regulatory analysis with one or a combination of these alternative models in the future. The EPA is considering attributes such as transparency, sensitivity, usability, accessibility, uncertainties, scope, and relevance of available models and tools. The EPA solicits comments on the available power sector modeling alternatives and the best approach to conducting future regulatory analyses in the sector. For consistency with modeling conducted for the *Regulatory Impact Analysis for the Final Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units,* the analysis in this EIA estimates impacts of the proposed repeal by applying a transparent and reproducible methodology that is documented above and fully available to the general public.

- EPA strives to use the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for this detailed power sector modeling. However, several key inputs to the model are subject to uncertainty and may affect the overall composition of electric power generation fleet in the model results and could thus have an effect on the estimated costs and impacts of this action. These key modeling uncertainties include:
    - **Electricity demand:** The analysis includes an assumption for future electricity demand. This is based on AEO 2025 reference case with incremental demand representing EPA estimates of electric vehicle demand and demand associated with data center applications.[11] To the extent electric demand is higher or lower, it may increase/decrease the projected future thermal/renewable composition of the fleet. Hence higher demand, all else

[11] For details, see Chapter 3 of the IPM documentation available at: https://www.epa.gov/power-sector-modeling.

equal, may result in fewer expected retirements and greater levels of turbine additions, while a different load shape could incentivize different levels of renewable energy penetration.

- **Natural gas supply and demand:** The baseline includes significant growth in LNG exports, driving tighter natural gas prices. To the extent prices are higher or lower, it would influence the use of natural gas for electricity generation and overall competitiveness of other EGUs (e.g., coal, renewable energy and nuclear units) and therefore the addition of new natural gas-fired turbines.
- **Longer-term planning by utilities:** To account for recent changes in retirement announcements by EGU owners and operators, the EPA has reverted to reflecting firm retirements in the model based on EIA-860 data and no longer supplementing these with other announcements of retirements by owners and operators. However, it is possible that decisions reflected in the EIA data may be revised in light of rapidly evolving market conditions.
- **One Big Beautiful Bill Act (OBBBA):** The OBBBA was signed into law in July of 2025. In order to illustrate the impact of the OBBBA on this rulemaking, the EPA included a baseline that incorporates key provisions of the OBBBA as well as imposing the CPS requirements on that baseline. However, additional effects of the OBBBA beyond those modeled in this EIA could result in a change in projected system compliance costs and emissions outcomes.[12]

While it is important to recognize these key areas of uncertainty, they do not change the EPA's overall confidence in the estimated impacts of the analysis conducted outside of the model and presented in this section. The EPA continues to monitor industry developments and makes appropriate updates to future analyses that reflect the best and most current data available.

[12] For details of OBBBA representation in this analysis please see IPM documentation, available at: https://www.epa.gov/power-sector-modeling.

2.3 Costs

2.3.1 Monitoring, Reporting, and Recordkeeping Costs

In this EIA, we estimate the impact of this proposed action on MR&R costs. This proposed action is estimated to reduce the MR&R costs incurred by industry to comply with the 2015 NSPS and the Phase 1 requirements of the 2024 CPS. These MR&R cost savings are estimated to begin in 2026 and occur through 2047, as shown in Table 1. For details on these estimates made for purposes of this economic analysis, see the associated spreadsheet in the docket titled *PV EAV Analysis - EGU GHG supplemental proposal - 2026.xlsx*.

Table 1 Impact of Proposal on State and Industry Annual Respondent Cost of Reporting and Recordkeeping Requirements (million 2024 dollars)

	2015 NSPS			**Phase 1 of 2024 CPS**			**Total**
Year	Industry	State	Total	Industry	State	Total	
2026	-0.95		-0.95	-0.04		-0.04	-0.99
2027	-1.0		-1.0	-0.08		-0.08	-1.1
2028	-1.1		-1.1	-0.13		-0.13	-1.2
2029	-1.2		-1.2	-0.17		-0.17	-1.3
2030	-1.2		-1.2	-0.21		-0.21	-1.5
2031	-1.3		-1.3	-0.25		-0.25	-1.6
2032	-1.4		-1.4	-0.30		-0.30	-1.7
2033	-1.5		-1.5	-0.34		-0.34	-1.8
2034	-1.5		-1.5	-0.38		-0.38	-1.9
2035	-1.6		-1.6	-0.42		-0.42	-2.0
2036	-1.7		-1.7	-0.46		-0.46	-2.2
2037	-1.8		-1.8	-0.51		-0.51	-2.3
2038	-1.8		-1.8	-0.55		-0.55	-2.4
2039	-1.9		-1.9	-0.59		-0.59	-2.5
2040	-2.0		-2.0	-0.63		-0.63	-2.6
2041	-2.1		-2.1	-0.68		-0.68	-2.7
2042	-2.1		-2.1	-0.72		-0.72	-2.9
2043	-2.2		-2.2	-0.76		-0.76	-3.0
2044	-2.3		-2.3	-0.80		-0.80	-3.1
2045	-2.4		-2.4	-0.84		-0.84	-3.2
2046	-2.4		-2.4	-0.89		-0.89	-3.3
2047	-2.5		-2.5	-0.93		-0.93	-3.4

Notes: (1) The two columns labeled "State" are blank and greyed out to signify that we estimate that state MR&R costs will not change due to the repeal of the 2015 NSPS and Phase 1 of the 2024 CPS. (2) Negative values indicate avoided costs. (3) Values have been rounded to two significant figures, and some are presented to no more than two decimal places. (4) Values may not appear to add correctly due to rounding. (5) These estimates are for purposes of the analysis in this EIA. For additional information, please see the spreadsheet in the docket titled *PV EAV Analysis - EGU GHG supplemental proposal - 2026.xlsx*.

2.3.2 Compliance and Real Resource Costs

This EIA estimates that this proposed action will avoid compliance costs. In particular, this section presents two sets of estimates of these avoided costs. First, this section presents estimates of the power sector's compliance cost. Second, this EIA presents the power sector's compliance cost estimates as the real resource costs paid by society, which differ from the sector compliance costs because of the accounting for transfer payments.

The compliance costs reported in this EIA are not social costs, although in this analysis we use compliance costs as a proxy for social costs. In particular, this analysis does not fully account for welfare changes arising from feedback between the electricity sector and the rest of the economy. Furthermore, this analysis omits costs due to interactions with preexisting market distortions outside the electricity sector.

As discussed in Section 2.1, this proposed action is estimated to result in potential cost savings related to the standards for simple cycle combustion turbines operating at greater than 40 percent capacity factor (*i.e.*, base load capacity). One way to represent compliance with these standards is to increase the size (capacity) of the new combustion turbines that are projected to operate above 40 percent. Table 2 below performs the calculation discussed in Section 2.1.1 that estimates the incremental fixed operations and maintenance (FOM) and capital costs necessary to build and maintain this greater capacity of combustion turbines. Table 2 lays out the total projected new simple cycle additions and the capacity of these additions that exceed the base load threshold in each run year.

Table 2 2030, 2035, 2040, and 2045 Change in Simple Cycle Combustion Turbine Buildout and Associated Costs

Run Year	Cumulative new Simple Cycle additions (GW)	New Simple Cycle additions that exceed 40% capacity factor (GW)	Capacity Factor of new Simple Cycle additions that exceed 40% capacity factor	Incremental Simple Cycle additions required in order to meet Phase 1 standards (GW)	Incremental FOM and Annualized Capital Cost (Millions of 2024$)	Cumulative FOM and Annualized Capital Costs (Millions of 2024$)
2030	42	0.44	45%	0.055	-5.7	-8.0
2035	42	1.0	50%	0.219	-22	-30
2040	47	0.0	N/A	0.0	0	-30
2045	77	0.0	N/A	0.0	0	-30

Note: Negative values indicate avoided costs.

Relative to cost impacts of many other EPA power sector rules, we project small cost savings because we anticipate that the Phase 1 limits for new combustion turbines would only affect a small amount of capacity. In contrast, a number of stakeholders have provided that the impacts of the Phase 1 standards could be much more significant. If, as some stakeholders have provided, more new units would have to limit operation because of the Phase 1 standards, this rule would have greater cost savings. Additionally, compliance pathways that differ from those assumed in this analysis could result in changes to emissions and cost estimates. For further discussion *see* Section 2.2.

Similarly, while this analysis does not project the construction of any new coal-fired units, EPA is aware that there are companies that are pursuing new coal-fired generation, including two new coal-fired steam generating facilities (one in Alaska and one in West Virginia).[13] To the extent that any of those projects do not include carbon capture and storage achieving emission limitations consistent with the NSPS standards that would be revoked as part of this proposal, this proposal would result in a cost savings for those units as they would no longer be obligated to install partial CCS. In other words, this proposed rule would provide cost savings for companies that wish to build coal-fired steam generating facilities without CCS, but it is up to individual companies on how they would like to proceed with their business decisions.

[13] *See* Project Selections for Broad Agency Announcement DE-FOA-0003605, Restoring Reliability: Coal Recommissioning and Modernization (Topic 1). Available at: https://www.energy.gov/hgeo/project-selections-broad-agency-announcement-de-foa-0003605-restoring-reliability-coal-0.

Table 3 presents EPA's estimates of changes in power sector compliance costs inclusive of MR&R costs (i.e., the change in costs paid by the power sector). These changes in costs are presented for the representative IPM run years 2030, 2035, 2040, and 2045 in real 2024 dollars. A negative cost reflects a projected reduction in compliance cost expenditures as a result of this action, while a positive cost denotes an increase.

Table 3 Change in National Power Sector Costs (million 2024 dollars)

2030 (Annual)	-9.4
2035 (Annual)	-32
2040 (Annual)	-33
2045 (Annual)	-34

Notes: (1) Negative values indicate avoided costs. (2) These costs include changes in MR&R costs.

Table 4 presents the present values (PVs) and equivalent annualized values (EAVs) of the cost savings, calculated for the 2026 to 2047 timeframe.

Table 4 Present Value and Equivalent Annualized Value Estimates of Cost Savings (million 2024 dollars, discounted to 2025) [a]

Power Sector Generating Costs		Monitoring, Reporting, and Recordkeeping Costs		Total Costs	
PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
3% Discount Rate					
340	21	33	2.1	370	23
7% Discount Rate					
210	19	21	1.9	230	21

Notes: (1) Values have been rounded to two significant figures, and some are presented to no more than three decimal places. (2) Values may not appear to add correctly due to rounding. (3) The PV and EAV presented in this table are based on a 22-year analytic timeframe (i.e., 2026 to 2047) using a 2025 present value year and beginning-of-period discounting.

The methodology in this section provides the EPA's best estimate of the change in costs in the electricity sector due to the proposed action. The projected change in the national power sector costs shown in Table 3 is the change in costs paid by the power sector because of this action. The projected change in power sector costs includes the avoided cost of additional resources that are used by the sector because of the proposed action, such as the cost of labor and materials. These "real resources" constitute the changes in physical and labor inputs purchased by the sector because of the EPA action.

However, the projected change in power sector cost also includes changes in tax payments, financing charges for new capital, and insurance. For example, when a new generator is built, the power sector cost includes the cost to purchase and install and operate the generator as well as the cost to finance the generator and expected taxes and insurance that will be paid on the investment.

Most tax payments, tax credits, and subsidy payments are transfers.[14,15] Transfers are shifts in money or resources from one part of the economy (e.g., a group of individuals, firms, or institutions) to another in a way that does not affect the total resources that are available to society. In other words, the loss to one part of the economy is exactly offset by the gain to another. Transfers should be excluded from estimates of the benefits and costs of a regulatory action.[16,17,18]

There are important sources of transfers included in the power sector cost analysis for this proposed action. Table 3 and Table 4 present the IPM compliance cost estimates from the perspective of the power sector, which is net of taxes paid and credits received. In contrast, Table 5 presents the full real resource costs of compliance with a presentation of changes in transfers paid.

The real resource approach provides an alternative estimate of the cost savings from this proposed action, adjusting the power sector cost analysis to account for the fact that the taxes represented in the analysis may be more accurately characterized as transfers. Whether the real

[14] OMB. (2003). *Circular A-4: Regulatory Analysis*. Washington DC. https://www.whitehouse.gov/wp-content/uploads/2025/08/CircularA-4.pdf
[15] U.S. EPA. (2024). *Guidelines for Preparing Economic Analyses (3rd edition)*. EPA-240-R-24-001. Washington, DC. https://www.epa.gov/system/files/documents/2024-12/guidelines-for-preparing-economic-analyses_final_508-compliant_compressed.pdf
[16] Transfers themselves do affect behavior, and therefore, their presence should be accounted for when estimating the social cost, social benefits, and distributional effects of a regulatory action.
[17] OMB. (2003). *Circular A-4: Regulatory Analysis*. Washington DC. https://www.whitehouse.gov/wp-content/uploads/2025/08/CircularA-4.pdf
[18] U.S. EPA. (2024). *Guidelines for Preparing Economic Analyses (3rd edition)*. EPA-240-R-24-001. Washington, DC. https://www.epa.gov/system/files/documents/2024-12/guidelines-for-preparing-economic-analyses_final_508-compliant_compressed.pdf

resource costs are greater or less than the sectoral compliance costs depends on the net effect of changes in transfers both paid to and paid by affected sectors.

Table 5 Change in Real Resource Costs under the Proposal (million 2024 dollars)

	[1] Total Power Sector Compliance Costs (Table 3)	[2] Change in Transfers: Corporate Income Taxes and Other Transfers	[3] Change in Real Resource Costs
2030	-9.4	-2.4	-7.1
2035	-32	-9.0	-23
2040	-33	-9.0	-24
2045	-34	-9.0	-25
	3 % Discount Rate		
PV (2026 to 2047)	-370	-99	-270
EAV (2026 to 2047)	-23	-6.2	-17
	7 % Discount Rate		
PV (2026 to 2047)	-230	-61	-170
EAV (2026 to 2047)	-21	-5.5	-15

Notes: (1) Negative values indicate avoided costs. (2) Column [3] = [1] - [2]. (3) As presented in Table 3, Column [1] includes changes in power sector compliance costs; monitoring, reporting, and recordkeeping costs; and tax payments. That is, Column [1] = [3] + [2]. (4) Column [2] reports the change in tax credits payments annualized using the private cost of borrowing and book life for eligible technologies (5) Column [2] is recovered from the difference in capital charge rates and capital recovery factors applied in IPM to new capital. (6) Present values are discounted to the 2025 analysis year. (7) Values rounded to two significant figures.

Table 5 presents the real resource costs under the proposed action. To start, Column 1 of Table 5 shows the change in power sector costs reported in Table 3, which represents the expenditures that the power sector will not have to make as a result of the proposed action. Column 2 reports the estimated net change in taxes and other transfers paid by the sector (e.g., investment taxes, insurance). The projected incremental change in real resource costs presented in Column 3 is calculated as the power system cost change minus the net change in taxes and transfers. That is, Column 3 equals Columns 1 less Column 2. This calculation of the real resource cost provides a transfer-adjusted estimate of the incremental costs projected to not occur as a result of this proposed action (negative values indicate costs not expected to occur).

Capital costs in Columns 1 and 3 are amortized using the private cost of borrowing over the assumed book life of the capital investment. The cost of borrowing, financing period, and book life varies by technology and owner-type.[19]

In the analysis of the repeal of the other 2024 CPS requirements, the EPA estimated other categories of transfers, such as changes in various tax credits. Those transfer categories are not presented here because those transfers would not change from the baseline under the assumptions of this analysis. However, if electric generating unit (EGU) operators chose other compliance strategies than assumed in this analysis, changes of these other transfers may be estimated.

2.3.3 Impacts on Emissions, Fuel and Prices

The methodology in this analysis assumes that compliance with the Phase 1 NSPS requirements is achieved with larger or more numerous combustion turbines and no resulting change in generation, fuel use, fuel prices, nor emissions.

2.3.4 Small Entity Analysis

The Regulatory Flexibility Act (RFA; 5 U.S.C. §601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104121), provides that whenever an agency publishes a proposed rule, it must prepare and make available an initial regulatory flexibility analysis (IRFA), unless it certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. §605[b]).

Small entities include small businesses, small organizations, and small governmental jurisdictions. An IRFA describes the economic impact of the rule on small entities and any significant alternatives to the rule that would accomplish the objectives of the rule while minimizing significant economic impacts on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden, or otherwise has a positive economic effect on the small entities subject to the rule.

[19] *See* Chapter 10 of IPM documentation. Available at: https://www.epa.gov/power-sector-modeling.

The EPA performed a small entity screening analysis for impacts on all affected EGUs by comparing compliance costs to historic revenues at the ultimate parent company level. This is known as the cost-to-revenue or cost-to-sales test, or the "sales test." The sales test is an impact methodology the EPA employs in analyzing entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is frequently used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Also, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by the EPA on compliance with the Regulatory Flexibility Act (RFA)[20] and is consistent with guidance published by the U.S. Small Business Administration's (SBA) Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities.[21]

The Phase 1 NSPS requirements would have affected the buildout and operation of future simple cycle combustion turbine additions. Costs are projected to peak in 2035 and as such, the analysis focuses on this year. While IPM can provide important information about the future operation and addition of natural gas capacity over the analysis period, the model does not project actions taken by individual firms.[22] Hence, as a proxy for the future gas capacity built by small entities, the EPA assumed that the same small entities identified using the process outlined below would continue to build the same share of future capacity additions projected by IPM over the forecast period. The EPA reviewed historical data and planned builds since 2017 to determine the universe of simple cycle combustion turbine additions as outlined in EPA National Electric Energy Data System (NEEDS) v.7 database. The NEEDS database includes operational capacity in the year of publication as well as capturing planned/committed units that are likely to

[20] The RFA compliance guidance to EPA rule writers can be found at https://www.epa.gov/sites/production/files/2015-06/documents/guidance-regflexact.pdf.
[21] See U.S. SBA Office of Advocacy. (2017). *A Guide For Government Agencies: How To Comply With The Regulatory Flexibility Act.* Available at: https://advocacy.sba.gov/wp-content/uploads/2019/06/How-to-Comply-with-the-RFA.pdf.
[22] For a fuller discussion of limitations of the modeling, please see Section 2.2

come online because ground has been broken, financing obtained, or other demonstrable factors indicate a high probability that the unit will be built before June 30, 2028.[23]

Based on these criteria, the EPA identified a total of 16 GW of simple cycle combustion turbine units greater than 25 MW built since 2017. Next, we determined power plant ownership information, including the name of associated owning entities, ownership shares, and each entity's type of ownership. Ownership information for these assets was obtained primarily using data from Ventyx[24], supplemented by research using S&P[25] and publicly available data.

Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types.[26] These ownership types are:

1. **Investor-Owned Utility (IOU)**: Investor-owned assets (e.g., a marketer, independent power producer, financial entity) and electric companies owned by stockholders, etc.
2. **Cooperative (Co-Op)**: Non-profit, customer-owned electric companies that generate and/or distribute electric power.
3. **Municipal**: A municipal utility, responsible for power supply and distribution in a small region, such as a city.
4. **Sub-division**: Political subdivision utility is a county, municipality, school district, hospital district, or any other political subdivision that is not classified as a municipality under state law.
5. **Private**: Similar to an investor-owned utility, however, ownership shares are not openly traded on the stock markets.
6. **State**: Utility owned by the State.
7. **Federal**: Utility owned by the federal government.

Next, the EPA used the D&B Hoover's online database, the Hitachi Energy Velocity Suite, and the S&P database to identify the ultimate owners of power plant owners identified in the NEEDS database. This was necessary, as many majority owners of power plants (listed in

[23] For details please see Chapter 4.3 IPM base case documentation, available at: https://www.epa.gov/power-sector-modeling.
[24] The Hitachi Energy Velocity Suite consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: https://www.hitachienergy.com/us/en/products-and-solutions/energy-portfolio-management/energy-analytics-software-solutions/energy-market-insights-software-solution.
[25] The S&P database consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: www.capitaliq.spglobal.com.
[26] Throughout this analysis, the EPA refers to the owner with the largest ownership share as the "majority owner" even when the ownership share is less than 51 percent.

Ventyx) are themselves owned by other ultimate parent entities (listed in D&B Hoover's).[27] In these cases, the ultimate parent entity was identified via D&B Hoover's, whether domestically or internationally owned.

The EPA followed SBA size standards to determine which non-government ultimate parent entities should be considered small entities in this analysis. These SBA size standards are specific to each industry, each having a threshold level of either employees, revenue, or assets below which an entity is considered small.[28] SBA guidelines list all industries, along with their associated North American Industry Classification System (NAICS) code[29] and SBA size standard. Therefore, it was necessary to identify the specific NAICS code associated with each ultimate parent entity in order to understand the appropriate size standard to apply. Data from D&B Hoover's was used to identify the NAICS codes for most of the ultimate parent entities. In many cases, an entity that is a majority owner of a power plant is itself owned by an ultimate parent entity with a primary business other than electric power generation. Therefore, it was necessary to consider SBA entity size guidelines for the range of NAICS codes listed in Table 6. This table represents the range of NAICS codes and areas of primary business of ultimate parent entities that are majority owners of potentially affected EGUs in the historical record.

[27] The D&B Hoover's online platform includes company records that can contain NAICS codes, number of employees, revenues, and assets. For more information, see: https://www.dnb.com/en-us/products/dnb-hoovers.html.
[28] SBA's table of size standards can be located here: https://www.sba.gov/document/support--table-size-standards.
[29] North American Industry Classification System can be accessed at the following link: https://www.census.gov/naics/.

Table 6 SBA Size Standards by NAICS Code

NAICS Codes	NAICS U.S. Industry Title	Size Standards (number of employees)
221111	Hydroelectric Power Generation	750
221112	Fossil Fuel Electric Power Generation	950
221113	Nuclear Electric Power Generation	1,150
221114	Solar Electric Power Generation	500
221115	Wind Electric Power Generation	1,150
221116	Geothermal Electric Power Generation	250
221117	Biomass Electric Power Generation	550
221118	Other Electric Power Generation	650
221121	Electric Bulk Power Transmission and Control	950
221122	Electric Power Distribution	1,100
221210	Natural Gas Distribution	1,150

Note: This table is an example of the NAICS codes that comprised this analysis. For a complete list, please see the accompanying workbook. Based on size standards available at the following link: https://www.sba.gov/document/support--table-size-standards). Source: SBA, 2023.

The EPA compared the relevant entity size criterion for each ultimate parent entity to the SBA size standard noted in Table 6. We used the following data sources and methodology to estimate the relevant size criterion values for each ultimate parent entity:

1. **Employment, Revenue, and Assets**: The EPA used the D&B Hoover's database as the primary source for information on ultimate parent entity employee numbers, revenue, and assets.[30] In parallel, the EPA also considered estimated revenues from affected EGUs based on analysis of IPM estimates for the baseline for 2035. The EPA assumed that the ultimate parent entity revenue was the larger of the two revenue estimates. In limited instances, supplemental research was also conducted to estimate an ultimate parent entity's number of employees, revenue, or assets.

2. **Population**: Municipal entities are defined as small if they serve populations of less than 50,000.[31] The EPA primarily relied on data from the Ventyx database and the U.S. Census Bureau to inform this determination.

[30] Estimates of sales were used in lieu of revenue estimates when revenue data was unavailable.
[31] The Regulatory Flexibility Act defines a small government jurisdiction as the government of a city, county, town, township, village, school district, or special district with a population of less than 50,000 (5 U.S.C. section 601(5)). For the purposes of the RFA, States and Tribal governments are not considered small governments. EPA's *Final Guidance for EPA Rulewriters: Regulatory Flexibility Act* is located here: https://www.epa.gov/sites/default/files/2015-06/documents/guidance-regflexact.pdf.

Ultimate parent entities for which the relevant measure is less than the SBA size standard were identified as small entities and carried forward in this analysis. Using this analysis, the EPA identified 21 percent of the simple cycle combustion turbine (25 total entities) additions over the historical period were attributed to small entities as summarized in Table 7 below.

Table 7 Historical Simple Cycle Combustion Turbine Additions (2017-present)

Total Additions (GW)	Total Additions by Small Entities (GW)	Share of Small Entities to Total Build (%)
16.1	3.4	21%

As shown in Section 2.3.2, baseline costs are projected to peak in 2035, and these costs are driven by owners and operators increasing the capacity of their combustion turbine additions, while not changing their generation. We assume that the historical share is maintained, *i.e.*, of total projected simple cycle combustion turbine additions, 21 percent continue to be built by the small entities identified in the historical period. Total avoided compliance costs calculated in Section 2.3.2 of this EIA were calculated in the manner described above, the costs attributed to small entities were calculated by multiplying the total costs to the share of the historical build attributed to small entities. These costs were then shared to individual entities using the ratio of their build to total small entity additions in the historical dataset.

As indicated above, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by EPA on compliance with the RFA and is consistent with guidance published by the SBA's Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities. The potential impacts, including compliance costs, of the proposed repeal on simple cycle combustion turbines owned by small entities are summarized in Table 8. All costs are presented in 2024 dollars. The EPA estimated the annual net compliance cost savings to small entities to be approximately $6.8 million in 2035.

Table 8 Projected Impact of the Proposal on Small Entities in 2035

EGU Ownership Type	Number of Potentially Affected Entities	Total Net Compliance Cost Change ($2024 millions)	Number of Small Entities with Compliance Costs >=1% of Generation Revenues	Number of Small Entities with Compliance Costs >=3% of Generation Revenues
Investor Owned Utility	4	-1.6	0	0
Co-op	2	-0.4	0	0
Municipal	2	-0.2	0	0
Private	17	-4.6	0	0
Total	**25**	**-6.8**	**0**	**0**

Note: Negative costs indicate avoided costs.

The EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent. Of the 25 entities that own simple cycle combustion turbine units considered in this analysis, all are projected to experience reductions in compliance costs – i.e., none are projected to experience compliance costs greater than or equal to 1 percent of generation revenues in 2035. This action will therefore not have a significant economic impact on a substantial number of small entities.