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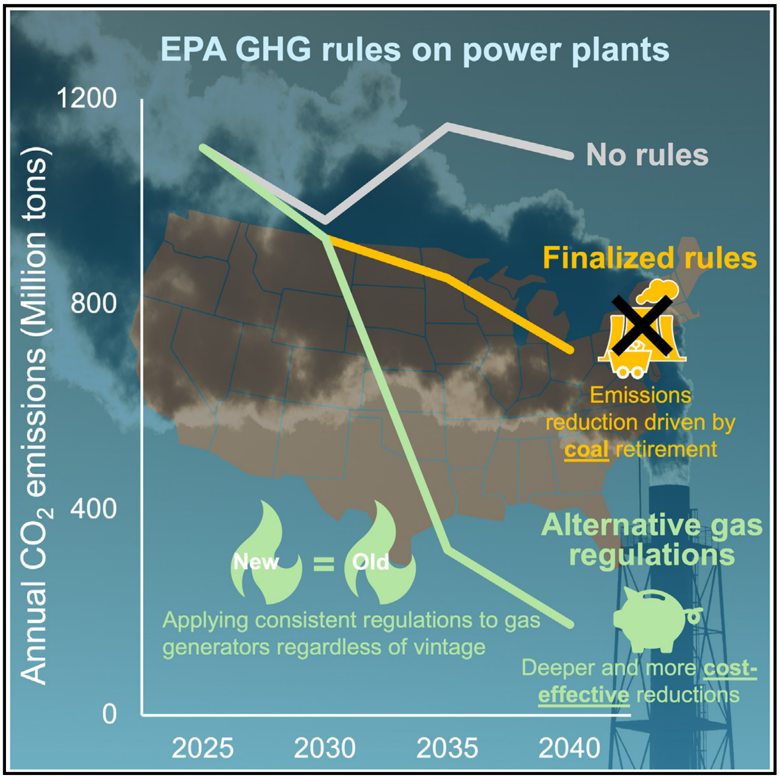
Article

US EPA's power plant rules reduce CO_2 emissions but can achieve more cost-efficient and deeper reduction by regulating existing gas-fired plants

Graphical abstract



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In brief

In 2024, the US EPA finalized complex greenhouse gas emissions regulations for power plants that provide multiple mitigation options for generators, making overall emissions reduction outcomes unclear. By incorporating the new regulations into a capacity expansion model, we show that these rules would bring significant emissions reductions at low abatement costs primarily due to coal retirements. However, regulations applied to new gas generators could encourage greater use of inefficient older plants, which could be improved by consistently regulating new and existing gas generators.

Highlights

- US EPA's 2024 power plant rules can halve sectoral emissions
- Coal plant retirements are responsible for the vast majority of emissions reductions
- Omitting existing gas plants from the 2024 EPA rules missed additional emissions reductions
- Setting equal rules for new and existing gas plants cost-effectively reduces emissions

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US EPA's power plant rules reduce CO_2 emissions but can achieve more cost-efficient and deeper reduction by regulating existing gas-fired plants

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SCIENCE FOR SOCIETY Back in 2014, the US Environmental Protection Agency (EPA) proposed greenhouse gas (GHG) regulations to decarbonize power plants, which account for a quarter of the nation's total emissions. These regulations were struck down by the Supreme Court in 2022 due to lack of statutory authority to set a sector-wide emissions standard. Responding to this decision, the EPA finalized new rules in 2024, specifying different generator-level performance standards based on technology, vintage, and utilization rate. The new rules also offer various decarbonization compliance options, which introduces complexity, making the overall decarbonization outcome less clear. By integrating the complex rules into an advanced capacity expansion model, we find that the EPA rules can cost-effectively reduce CO_2 emissions by encouraging coal retirements, but the rules miss additional emissions reductions by failing to set regulations for existing natural gas generators. Our results stress the importance of consistent regulations across all gas generators, regardless of vintage.

SUMMARY

Targeting one of the largest CO_2-emitting sectors, the US Environmental Protection Agency (EPA) finalized new regulations on power plant emissions in 2024. However, the regulations are complex, with multiple mitigation options for compliance, making it difficult to understand their consequential effects on total CO_2 emissions. We evaluate these effects by enhancing a capacity expansion model via incorporating new detailed operational constraints tailored to different technologies based on the EPA's new rules. We show that the new rules could nearly double power sector CO_2 emissions reductions through 2040, bringing emissions to about 51% below the 2022 level at low average cost per ton avoided, driven primarily by coal retirements. However, the rules omit regulations on existing natural gas generators, encouraging greater use of inefficient older gas plants. We find that emissions could be cost-effectively driven to 81%–88% below 2022 levels if the EPA's rules were applied equally to all gas generators, regardless of vintage.

INTRODUCTION

To keep global warming "well below" 2°C (compared to the pre-industrial levels), nearly 200 nations agreed to cut greenhouse gas (GHG) emissions under the Paris Agreement, but no specific guidance on how to effectively reduce emissions was provided.[1] In the United States, the Inflation Reduction Act (IRA) of 2022 and Infrastructure Investment and Jobs Act of 2021 collectively deploy over $500 billion in tax credits, grants, rebates, and loan guarantees to incentivize clean energy investment and reduce GHG emissions in the United States.[2] These policies are likely to reduce US GHG emissions to 33%–40% below 2005 levels by 2030 and 43%–48% by 2035,[3] falling short of the US nationally determined contribution (NDC) under the Paris Agreement (50%–52% below 2005 emissions in 2030)[4] and long-term strategy (net zero by 2050).[5] To further reduce GHG emissions, the Biden administration proposed and finalized several additional sectoral emissions regulations (including transportation, oil, and methane gas emissions) and efficiency standards. The regulations on CO_2 emissions for fossil fuel-fired electricity-generating units (EGUs) recently finalized by the US Environmental Protection Agency (EPA) under Section 111 of the Clean Air Act are among the most significant of these regulations.[6] The EPA power plant regulations introduce different

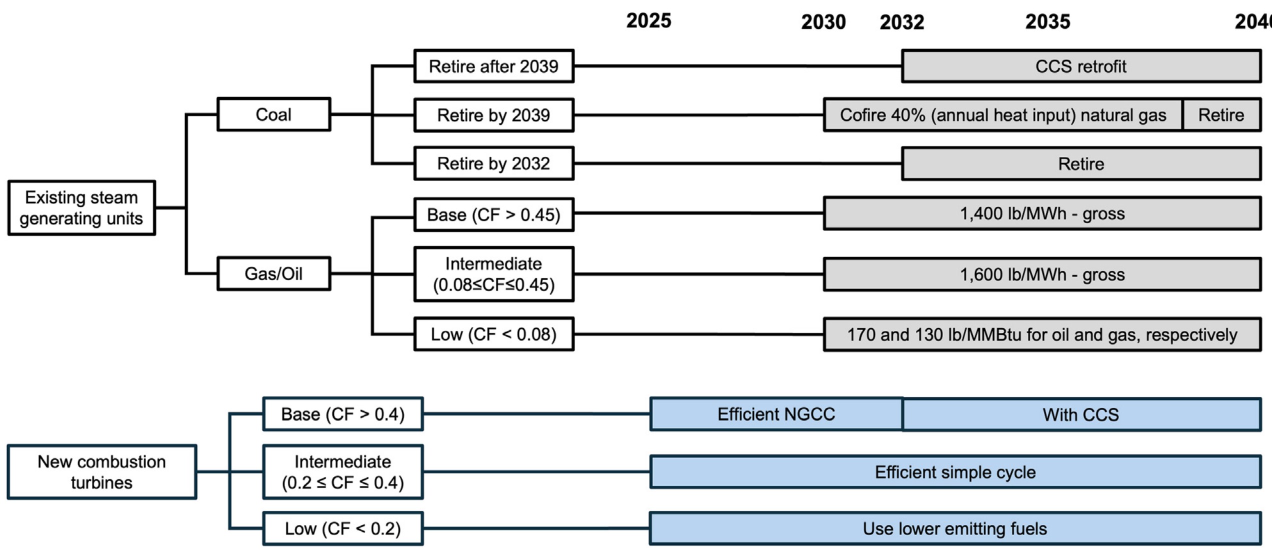

Figure 1. The best system of emissions reduction (BSER) determined by the EPA to meet required emissions standards in each modeling period for different generator types

emissions performance standards for several different classes of generators with different deadlines to meet those requirements. To meet these emissions standards, the EPA also determined the best system of emissions reduction (BSER) by "taking into account costs, energy requirements, and other statutory factors."[6] For example, the BSER for existing coal-fired steam generators is to either equip carbon capture and storage (CCS) by 2032 or co-fire natural gas (NG) by 2030, depending on their planned retirement date. While the BSER for *new base-load* NG combustion turbines to meet emissions standards is to equip CCS by 2032, there are no such strict requirements for *existing* gas turbines—the BSER for existing gas turbines is "routine methods of operation and maintenance." Operational utilization rates (capacity factors, CFs) also affect how these regulations are applied to specific generators. For example, new gas generators that run infrequently in a year ("non-baseload generators," defined as generators with CF below 40%) would not be subject to this CCS requirement. Figure 1 summarizes this complex set of requirements.

The EPA proposed its first CO_2 emissions regulations for existing fossil fuel-fired power plants in 2014, known as the Clean Power Plan (CPP).[7] The CPP set state-specific emissions reduction targets and provided flexibility for states to determine how to reach these goals (e.g., with mass- or rate-based emissions limits and the option for emissions permit trading across linked states). Although many studies show that CPP would have resulted in significant climate and public health benefits,[8–11] the proposed rule was curtailed by the Supreme Court due to "the lack of the authority" to set a sector-wide GHG emissions performance standard based on generation shifting.[12]

Unlike the CPP, new GHG regulations finalized by the EPA in 2024 provide different generator-level ("inside the fence line") performance standards for power plants with different technologies, vintages, and utilization rates (CF). The complexity of the proposed EPA rules makes it difficult to estimate how the new regulations would affect the US power system, including capacity investment, retrofit and retirement decisions, operations, and GHG emissions. Although one study has estimated the overall impacts from the new GHG rules from a collection of energy system models,[13] the effects of the rules targeting each class of generators and how they interact with one another in various combinations remain unclear. Furthermore, no prior work has estimated the emission and economic impacts of key changes made to the rules between their initial introduction and the adoption of the final rules nor explored alternative regulatory strategies that could yield additional cost-effective emissions reductions. Finally, within hours of his inauguration on January 20, 2025, US President Donald Trump issued an executive order directing the administrator of the EPA to consider the elimination of the use of the "social cost of carbon" in regulatory impact analysis and submit a report within 30 days "on the legality and continuing applicability" of the 2009 public endangerment finding that underpins the EPA's authority to regulate GHGs under the Clean Air Act.[14] As such, the Trump administration is expected to initiate rule-making to rescind regulations of GHG emissions from power plants and vehicles and to cease defending these rules from court challenges. This work thus provides timely insights into the likely impacts of potential repeal or revision of the final rules.

To fill the above research gaps and provide clear policy-relevant insights, we extend a state-of-the-art, open-source power system capacity expansion model, GenX,[15,16] by incorporating detailed operational constraints tailored to different technologies to represent the EPA rules. In this work, we formulate new constraints to reflect the various compliance pathways and emissions performance standards for each class of generators and model a range of scenarios with different combinations of rules under different uncertainties. Our modeling results show that the majority of emissions reductions are associated with the regulation of coal-fired generators. Constraints on new NG

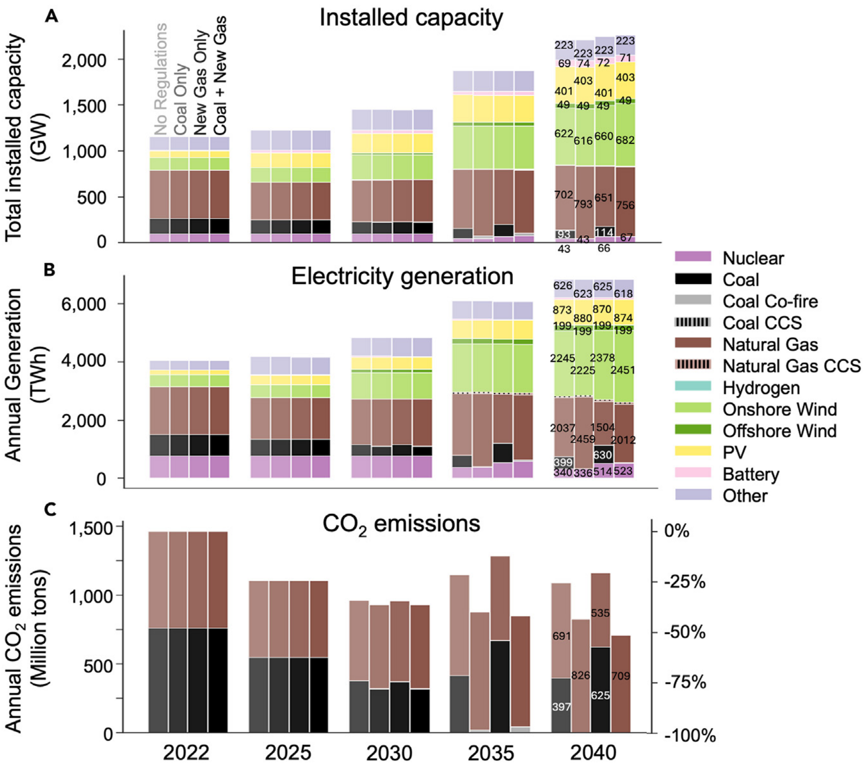

Figure 2. Overview of the power system under different regulation scenarios

Total installed capacity (A), electricity generation (B), and CO_2 emissions (C) by technology under different regulation scenarios in each period. "No regulations": not including EPA GHG regulations; "coal only": including regulations only on coal-fired power plants; "new gas only": including regulations only on new baseload natural gas-fired power plants; "coal + new gas": including regulations on both coal and new baseload natural gas-fired power plants (finalized rules). The 2022 data are from EIA and other periods are modeling outputs (base, capacity factor >40%).

generators help reduce emissions further but lower the overall system efficiency, reducing emissions at a very high incremental cost per ton of CO_2 avoided. Additionally, we determine that applying more consistent emissions regulations to all gas generators, regardless of their vintage, would avoid biasing operations toward less efficient generators and improve the economic efficiency of the proposed rules.

RESULTS

Method summary

To estimate the impacts of the EPA regulations, we apply a capacity expansion model, GenX, to the power system of the contiguous United States (CONUS). We add new features to GenX, such as burning multiple fuels in a single generator (co-firing), retrofitting existing gas turbines with CCS, and meeting maximum CF requirements to avoid regulations, to accurately represent detailed operational constraints set by the EPA regulations. With these new futures, GenX will determine a cost-effective resource portfolio for the future US grid while meeting all EPA regulations. In this work, we simulate the grid capacity investment and operations from 2023 to 2040 and quantify emissions associated with electricity generation. See the Methods section for data and assumptions used in GenX and modeling details.

Large emissions reductions from new EPA emissions rules

The EPA finalized two separate rules targeted at two groups of fossil fuel-fired generators: (1) existing steam-generating units (which we refer to as the "coal" rule because most of the existing steam-generating units are coal fired) and (2) new combustion turbines, including combined cycles ("new gas"). To understand the impacts of each rule on the system, we design three scenarios: "coal only," "new gas only," and "coal + new gas." We also include a benchmark case ("no regulations"), where no EPA rules are considered. All cases include relevant tax credits enacted by the IRA and projected electricity demand accounting for IRA impacts on electrification of transportation and heating and production of electrolytic hydrogen.[17] Figure 2 shows installed capacity, electricity generation, and CO_2 emissions across all technology types under the four scenarios.

Impacts of each EPA rule on the system

The imposition of rules on existing coal-fired generators has the most significant impact on installed capacity, generation, and emissions outcomes. This rule requires coal-fired generators with no planned retirement before 2039 to be retrofitted with CCS from 2032 and generators that are planned to retire before 2039 to co-fire at least 40% NG (on a heat input basis) from 2030 or meet equivalent emissions rates (though we assume herein that no better compliance options are available). No additional constraints will be applied to coal-fired generators with scheduled retirement before 2032. Figure 2A shows that constraints on coal generators result in 6 GW of coal retrofitted to co-fire with NG in 2030 and and 28 GW in 2035 (4% and 99% of operational coal capacity, respectively). Only 1% of coal capacity in 2035 is retrofitted with CCS. We also observe an additional 90 GW of NG turbine capacity in 2040, but almost no coal-fired generators choose to add CCS equipment even with the tax credits that the IRA provides for CCS (45Q; see "Emission impacts under future uncertainties" for a more detailed discussion about the impacts of how 45Q is modeled in this study). Regulations on coal-fired generators significantly reduce installed coal capacity (accelerating the retirement of coal by 1 GW in 2030, 81 GW in 2035, and 94 GW in 2040) and associated generation, accounting for the majority of emissions reductions from the EPA rules. Compared with the "no regulations" case, "coal only" alone reduces CO_2 emissions from 2035 onward (during which the EPA regulations for coal-fired generators apply) by 24% in

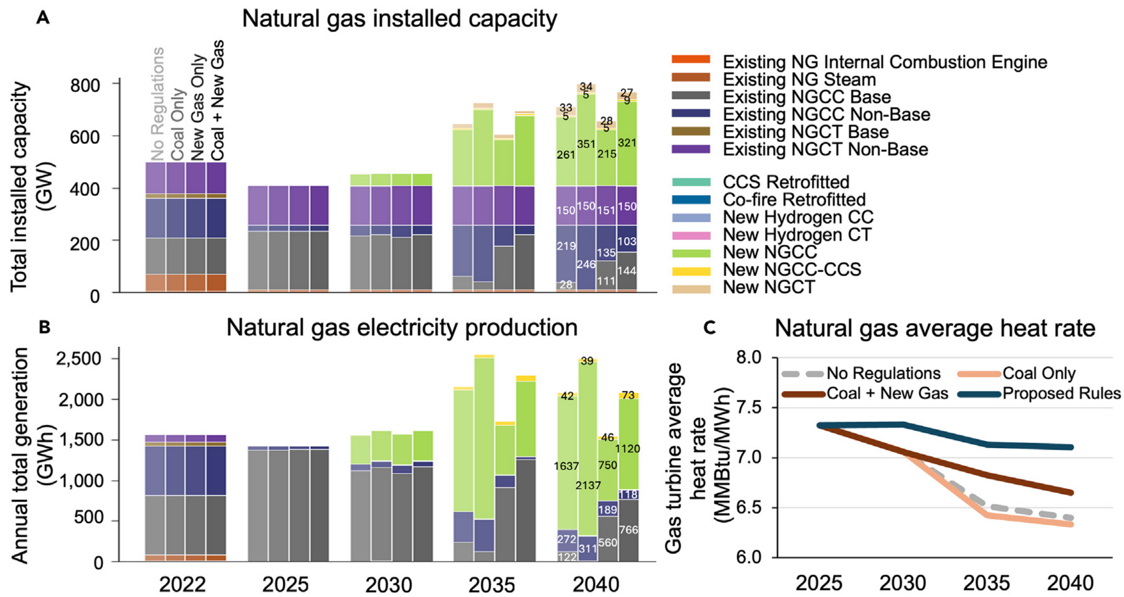

Figure 3. Natural gas power plants under under different regulation scenarios

Total installed capacity (A), electricity generation for natural gas and H_2-fueled generators (B), and average heat rates across all natural gas power plants (C) under different regulation scenarios in each period. "No regulations": not including EPA GHG regulations; "coal only": including regulations only on coal-fired power plants; "new gas only": including regulations only on new baseload natural gas-fired power plants; "coal + new gas": including regulations on both coal and new baseload natural gas-fired power plants (finalized rules). The 2022 data are from EIA and other periods are modeling outputs (base, capacity factor > 40%).

each period (12% reductions in cumulative emissions from 2023 to 2040). Emissions in 2035 and 2040 are 270 and 260 million tons of CO_2 ($MtCO_2$) lower, respectively, than the "no regulations" case, reaching 40% and 43% below 2022 power sector emissions (Figure 2C). Regulations on existing oil/gas steam turbines do not have significant impacts on system emissions as most of them retire or run at very low utilization levels under the "no regulations" scenario due to low efficiency and high marginal costs of generation.

When adding regulations only on new combustion turbines without the coal regulations ("new gas only"), new NG turbines must either keep the CF below 40% or install CCS in 2032. Of 215 GW of new NG combined-cycle (NGCC) capacity (no CCS) installed by 2040, 211 GW operates at 40% CF. The imposition of these constraints on new gas turbines effectively increases the cost of new gas capacity, resulting in more generation from coal, existing nuclear, and renewable resources (Figure 2B). Although emissions from the combustion of NG are reduced by 23% in 2040, increased use of coal makes the "new gas only" scenario exhibit even greater total emissions than the "no regulations" benchmark, resulting in a 4% increase in cumulative emissions from 2023 to 2040 (870 $MtCO_2$ increase). When this gas rule is added to "coal only" rule ("coal + new gas"), as in the finalized EPA rules, it incrementally reduces CO_2 emissions by 115 $MtCO_2$ in 2040 (reaching 51% below 2022 emissions and 14% cumulative emissions reduction compared with the "no regulation" scenario). In this case, 66 GW more of onshore wind is added to the system relative to "coal only," with NG capacity reduced by 37 GW. Additionally, we observe 24 GW less nuclear retirement in 2040 compared with the "coal only" scenario.

Responses of natural power plants to the EPA rules

We still observe substantial emissions from the combustion of NG with the finalized rules. Therefore, we break down NG-fired generators into several subgroups based on their technology and operational status to understand how regulations on new NG turbines impact emissions from the combustion of NG (Figure 3).

Under the final EPA rules ("coal + new gas"), more new gas capacity is added through 2040 than the benchmark "no regulations" case but produces less generation. New installed capacity of NGCC without CCS ("New NGCC") increases by 23%, and generation from these units is reduced by 32%. Although most gas capacity is still new NGCC without CCS (321 GW, 42% of total installed gas combustion capacity in 2040), these units operate below 40% CF; 99% run at 40% CF and 1% run below 40% to avoid emissions standards for new baseload gas plants requiring CCS. New NGCC units provide 54% of electricity generation from NG combustion in 2040. In comparison, due to higher efficiency, new NGCC provides 86% of all gas-fired generation under "coal only", with 30 GW more installed capacity of new NGCC than "coal + new gas." Meanwhile, electricity generation from existing gas turbines almost doubles after the "new gas" rule is included. A small amount of new NGCC with CCS ("New NGCC-CCS") is added under "no regulations" (5 GW), and the regulation on new gas turbines increases this to 9 GW. However, the overall shift in generation toward less efficient existing gas-fired generators caused by the new gas regulations results in higher average heat rates for the overall gas fleet ("coal + new gas" scenario in Figure 3C) and increases emissions from the combustion of NG even compared with the "no regulations" scenario.

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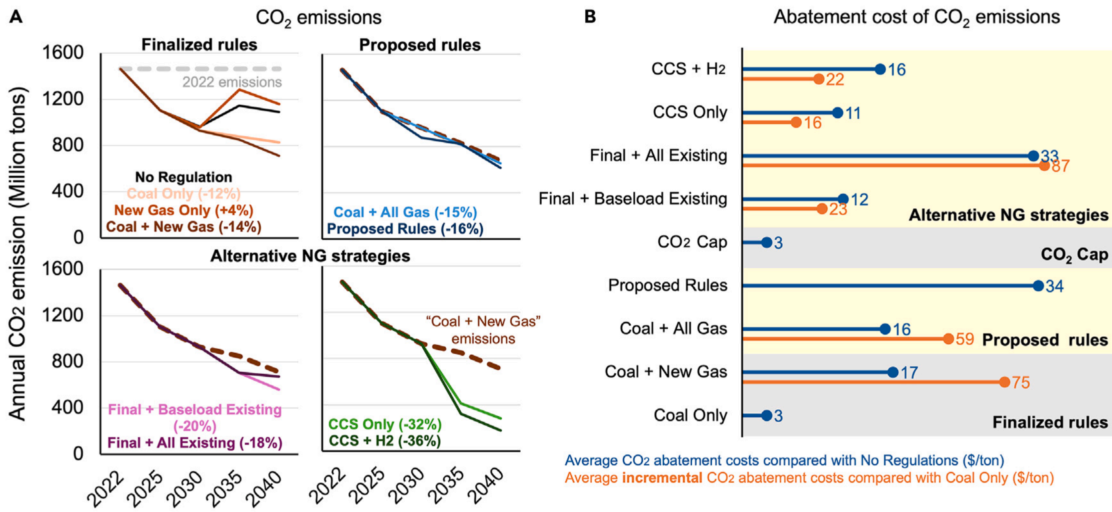

Figure 4. CO_2 emissions under various uncertainties assumptions

Annual CO_2 emissions in each period (A) and average abatement costs (B) under all scenarios. "No regulations": not including EPA GHG regulations; "coal only": including regulations only on coal-fired power plants; "new gas only": including regulations only on new baseload natural gas-fired power plants; "coal + new gas": including regulations on both coal and new baseload natural gas-fired power plants (finalized rules); "coal + all gas": "coal + new gas" + extending gas rules to include *large* baseload existing gas turbines; "proposed rules": GHG regulations proposed by the EPA in 2023; "CO_2 cap": not including EPA GHG regulations but setting a CO_2 emissions limit that is equal to emissions from "coal + new gas"; "final + baseload existing": "coal + new gas" + extending gas rules to include all *baseload* existing gas turbines; "final + all existing": "coal + new gas" + extending gas rules to include *all* existing gas turbines; "CCS only": requiring CCS for all non-peaker natural gas-fired turbines; "CCS + H_2": requiring CCS for all non-peaker natural gas-fired turbines and requiring CCS or 30% H_2 co-firing for natural gas peakers. Numbers after the scenario name are the reduction percentage in cumulative CO_2 emissions from 2023 to 2040 compared with the "no regulation" scenario. Abatement costs of "new gas only" are not listed because it has an emissions increase (base, capacity factor >40%).

Comparison between proposed and finalized rules

The EPA proposed power plant GHG rules in May 2023[18] and finalized the rules in May 2024.[6] There are a few major differences between the proposed and the final versions: (1) the finalization of rules on existing combustion turbines was delayed, as the EPA planned at that time to take "a new, comprehensive approach to cover the entire fleet of natural gas-fired turbines" in the future[19]; (2) the definition of baseload NG-fired generators was modified from a CF >50% to >40%; (3) a hydrogen (H_2) co-firing pathway in the BSER was removed for new non-peak gas turbines; (4) a subcategory of existing coal steam turbines (coal-fired generators that plan to retire by 2035, which must run with an annual utilization rate below 20% under proposed rules) was removed; and (5) the compliance date of coal CCS retrofit was delayed from 2030 to 2032. To evaluate the impacts of these changes from proposed to final rules, we compare impacts on capacity, operations, and emissions under the finalized rules ("coal + new gas"); a possible scenario including regulations on existing gas plants ("coal + all gas"); and the original proposed rules ("proposed rules," see details in Figure S4). Under "coal + all gas," we extend the finalized rules requiring CCS for only new baseload gas turbines to large, baseload existing gas turbines (capacity >300 MW and annual CF >40%), similar to the proposed rules.

Although regulations on existing gas generators have almost no impact on the installed capacity of either gas or other resources under "coal + all gas," total generation from gas turbines decreases as some large existing NGCC generators need to reduce utilization levels below 40% to avoid CCS retrofit from 2032 onward (Figure S9). However, this reduces overall emissions by only 16 and 22 $MtCO_2$ in 2035 and 2040, respectively, compared with "coal + new gas" (Figure 4). In 2035, the existing gas turbine capacity is 427 GW in our modeling, only 23 GW of which would be regulated (e.g., with capacity size >300 MW and CF >40%). Therefore, we find that the EPA's decision to delay the finalization of regulations on existing NG turbines is likely to have minimal negative impacts on either cumulative or annual emissions through 2040. We explore several other possible implementations of existing gas rules under "Alternative rules to more effectively limit emissions."

Compared with the proposed rules, the most significant difference is driven by the delayed compliance date of coal CCS retrofit (to 2032) and the removal of the subcategory of coal generators that plan to retire by 2035 (required to operate at <20% CF). As a result, the finalized rules have significantly more generation and emissions from coal in 2030 (Figure S9). In later periods (2035 and 2040), without H_2 co-firing requirements for non-peaker gas turbines, the final rules have more NG and less renewable capacity, and thus about 40 million tons more emissions in 2040, even after modifying the standard of baseload generators to cover more NG capacity. However, the finalized rules will lead to a more efficient system than the proposed rules due to less generation from inefficient existing gas generators (Figure 3C).

Emission impacts under future uncertainties

To assess how future uncertainties might impact the effectiveness of these rules, we evaluate the final rules (the "coal + new gas" scenario) under three groups of sensitivity analyses, exploring the impacts from the availability of renewable

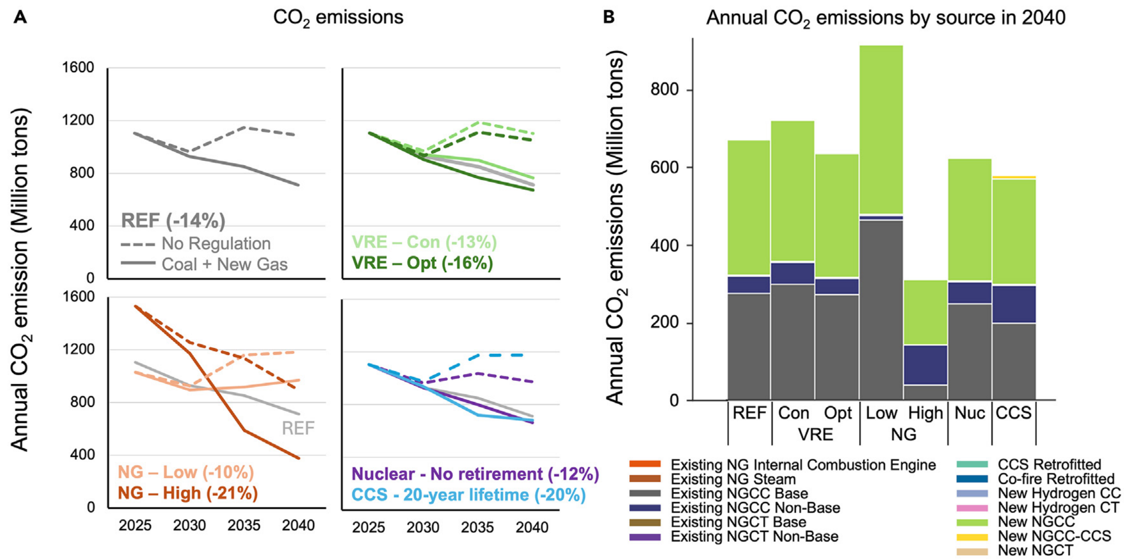

Figure 5. Changes from the alternative natural gas rules proposed by this study

Annual CO_2 emissions in each period (A) and emissions released from different types of natural gas or H_2-fired generators in 2040 (B) under the "coal + new gas" rules under different sensitivity scenarios. Numbers after the scenario name are the reduction percentage in cumulative CO_2 emissions from 2023 to 2040 compared with their corresponding "no regulation" scenarios (base, capacity factor >40%).

resources, prices of fossil fuels, and treatment of tax credits provided by the IRA (Figure 5).

In addition to the assumptions used by the base scenario (REF), we include another two wind and solar growth limit scenarios: optimistic (VRE-Opt) and conservative (VRE-Con). Table S2 includes assumptions of the compound annual growth rate for renewables, and Figure S5 shows the maximum annual renewable addition under different scenarios. As building renewable capacity in some regions can be expensive due to transmission expansion investments, the assumed maximum rate of growth in wind and solar capacity additions is likely to have a limited impact on installed capacity and electricity generation of gas turbines (Figure S10). However, we find that fuel prices have strong impacts on system emissions. We obtained low, reference, and high NG prices—\$2.8, \$3.9, and \$5.9/MMBtu (national average in 2040), respectively—from the US Energy Information Administration (EIA) *Annual Energy Outlook 2023*[20] (Figure S6). Interestingly, lower NG prices lead to lower emissions in the early periods (2025 and 2030), as they result in less generation from coal (and more from gas), while higher NG prices have lower emissions in later periods (2035 and 2040, Figure 5) after most coal capacity has retired. Overall, compared with REF under the final rule scenario, lower NG prices result in 36% more emissions in 2040 (34% below 2022 emissions levels) and higher NG prices result in 47% fewer emissions in 2040 (74% below 2022 emissions levels).

We also consider uncertainties related to tax credits provided by the IRA, including the extension of the 45U production tax credit for existing nuclear power plants and the treatment of 45Q tax credit for CO_2 sequestration. We assume in our REF cases that existing nuclear units will not retire prior to 2032 due to 45U, but permit the model to choose economic retirements in the 2035 and 2040 planning stages, as the current policy is scheduled to expire after 2032. It is plausible that some form of policy support may be extended to avoid nuclear retirements, so in order to understand the impacts of the interactions between nuclear retirements and other energy resources, we repeat all the analyses above without allowing any nuclear retirement ("nuclear-no retirement"). With renewable growth limits and fuel prices consistent with the REF scenario, we find that preventing any nuclear retirement after 2032 would reduce CO_2 emissions by 48 $MtCO_2$ in 2040 (reaching 55% below 2022 emissions levels).

Additionally, as we optimize capacity expansion in GenX in a myopic way (see methods), it is necessary to annuitize capital expenditures and spread the value of production-related tax credits over the financial life of each asset. Under the REF scenario, we assume a 30-year lifetime for CCS retrofit and new gas turbines, leading to a 45Q credit at an equivalent net-present value (NPV) payment of \$45/tCO_2 in 2022 USD (see "Power system modeling" in methods for details). In the "CCS 20-year lifetime" case, we instead assume a 20-year asset life for CCS retrofit and new gas turbines, which increases the equivalent value of the credit from \$45 to \$58/tCO_2. While these values are equivalent in NPV terms, the modeled value of the 45Q credit affects the marginal cost of qualifying generators and thus their position in the economic dispatch. We thus observe that modeling the NPV of 45Q over a 20-year asset life increases the capacity of coal CCS retrofits and new gas CCS from 1 and 9 GW to 61 and 54 GW, respectively, leading to 30 $MtCO_2$ of emissions reduction in 2040 (Figure S10). This finding indicates that CCS technologies are borderline economic for certain existing coal-fired generators and new gas turbines that are eligible for 45Q (and proximate to cost-effective transport and storage). Real-world investment decisions will incorporate more complex assessments of project risk, and different agents (with varying risk aversion) may opt for different strategies.

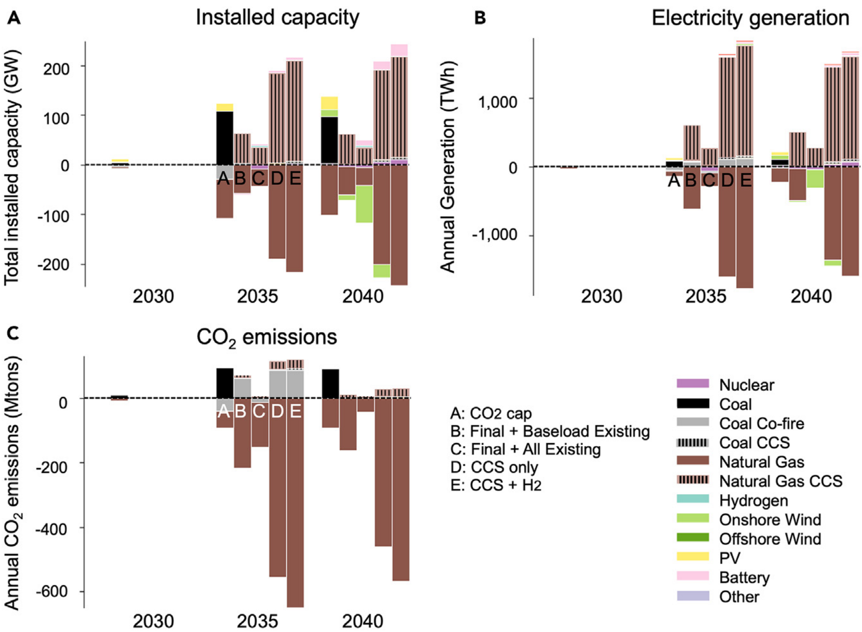

Figure 6. Annual CO_2 emissions in each period and average abatement costs under all scenarios

Differences between the "coal + new gas" rule and alternative strategies in total installed capacity (A), electricity generation (B), and CO_2 emissions (C) by technology in each period. "Coal + new gas": including regulations on both coal and new baseload natural gas-fired power plants (finalized rules); "CO_2 cap": not including EPA GHG regulations but setting a CO_2 emissions limit that is equal to emissions from "coal + new gas"; "final + baseload existing": "coal + new gas" + extending gas rules to include all *baseload* existing gas turbines; "final + all existing": "coal + new gas" + extending gas rules to include *all* existing gas turbines; "CCS only": requiring CCS for all non-peaker natural gas-fired turbines; "CCS + H_2": requiring CCS for all non-peaker natural gas-fired turbines and requiring CCS or 30% H_2 co-firing for natural gas peakers (base, capacity factor >40%).

Across all sensitivities, the EPA rules consistently reduce 2040 emissions by 18%–58% (reaching 34%–74% below 2022 emissions levels) and reduce 2023–2040 cumulative emissions by 10%–21% (2,000–4,700 $MtCO_2$ decrease), relative to the equivalent "no regulations" benchmark. NG prices have the most significant impacts on emissions outcomes. With low gas prices, economic coal retirement leads to low emissions even without EPA rules, and the implementation of GHG regulations further reduce 2040 emissions by only 18%. However, when NG prices are high, more coal-fired generators remain economic and avoid retirement, resulting in substantial emissions in the absence of EPA regulations. We thus observe the greatest emissions reductions from EPA rules in this high gas price scenario, with more than 500 $MtCO_2$ emissions avoided in both 2035 and 2040, relative to no regulations.

Alternative rules to more effectively limit emissions

The EPA's GHG regulations require different classes of generators to meet different emissions performance standards, with the performance standard based on several specific compliance options implementable at the plant (i.e., co-firing, carbon capture, etc.). This inside-the-fence-line approach is intended to be responsive to a 2022 Supreme Court decision[12] that struck down the more flexible sectoral emissions performance standards proposed by the EPA under the Obama administration (the so-called Clean Power Plan[7]). To compare the performance of the current proposed rules to a more flexible sector-wide emissions cap, we also evaluate a new scenario ("CO_2 cap") that has a national emissions limit equal to total emissions under the final rules ("coal + new gas") in each period. Compared with the final EPA rules (the "coal + new gas" scenario), we find that setting an emissions cap without any further regulations on the operations of generators results in more generation from existing coal, new NG, and renewable resources in lieu of generation from coal plants co-firing with gas or existing gas plants (Figures 6 and S11). Although the average cost of mitigation is relatively low under the EPA rules ($17/ton reduced from "no regulations" vs. "coal + new gas"), an emissions cap will always exhibit superior static efficiency. Indeed, the average cost to mitigate CO_2 emissions declines 82% under this emissions cap scenario to just $3/ton, compared with "coal + new gas" (Figure 4B).

Requiring CCS for existing NG plants from 2032

Since the EPA requested input and analysis on possible regulations for existing gas-fired generators,[19] we evaluate several strategies to regulate existing combustion turbines ("final + baseload existing" and "final + all existing" in Table 1). In addition to regulations on coal and new gas generators, "final + baseload existing" requires a CCS retrofit for all existing baseload gas combustion generators (>40% CF), regardless of their nameplate capacity. As a result, overall gas-fired capacity does not significantly change but more new gas with CCS is added to replace existing gas turbines, incrementally reducing 2040 emissions by 152 $MtCO_2$ (reaching 62% below 2022 emissions) at an average abatement cost of $12/$tCO_2$, a 29% improvement in average abatement cost vs. the final EPA rule.

In "final + all existing," we require *all* existing gas turbines to retrofit with CCS (regardless of CF). This requirement promotes some addition of gas CCS retrofit, but most existing gas turbines will still retire, and a significant amount of new non-baseload gas turbines that are not subject to CCS requirements are added to the system (Figure S11). Surprisingly, this strict regulation on existing gas-fired generators does not significantly reduce emissions, as the reductions from additional CCS retrofits are offset by emissions increases from more new gas capacity. Building a lot of new gas turbines that cannot run with CF greater than 40% also roughly doubles the average abatement cost relative to the final EPA rules ("coal + new gas"). The incremental cost of reductions achieved relative to "coal only" amounts to $87/$tCO_2$ under this strategy (Figure 4).

Table 1. Detailed description of new regulatory strategies proposed by this work

Name	Description
CO_2 cap	add a nation-wide CO_2 emissions cap that is at the same level as the emissions from the "coal + new gas" scenario
Final + baseload existing	extend the CCS requirement for new baseload NG-fired EGUs to existing *baseload* NG-fired EGUs
Final + all existing	extend the CCS requirement for new baseload NG-fired EGUs to all existing NG-fired EGUs
CCS only	from 2035, all non-peaker NG-fired EGUs (including both new and existing) must have CCS
CCS + H_2	from 2035, all non-peaker NG-fired EGUs (including both new and existing) must have CCS and peakers can choose either CCS or 30% H_2 co-firing

Setting equal standards for new and existing gas plants

Based on the observation from previous scenarios that imposing strict emissions regulations on only one category of gas turbines (new or existing) is likely to increase generation and emissions from the other category, we consider a pair of alternative strategies ("CCS only" and "CCS + H_2") that apply equivalent standards to both new and existing turbines. Under "CCS only," all non-peaker gas-fired generators (CF >20%) must generate electricity with CCS from 2035. Given the high costs of H_2, it is not economical to use H_2 in gas turbines for baseload operations, so "CCS + H_2" requires co-firing 30% H_2 in gas peakers ($\leq$20% CF), while all other gas turbines have to eventually be equipped with CCS beginning in 2035. In both cases, we keep the constraint on coal-fired generators the same as "coal only." Under both rules, most gas turbines retrofit with CCS in 2035 so that they can keep running at a relatively high utilization level. To avoid using expensive H_2, even more CCS is added under "CCS + H_2." Compared with the EPA rules ("coal + new gas"), this conversion to CCS reduces 2040 CO_2 emissions by 430 $MtCO_2$ under "CCS only" and 534 $MtCO_2$ under "CCS + H_2" (reaching 81% and 88% below 2022 emissions and 32% and 36% cumulative emissions reduction compared with the "no regulation" scenario, respectively). More importantly, extending regulations to all non-peakers (CF >20%) instead of regulating only baseload generators (CF >40%) reduces more emissions than applying rules only to new gas combustion generators ("coal + new gas") or extending current new gas rules to existing gas generators ("final + baseload existing" and "final + all existing") at a lower incremental cost. The incremental abatement costs for "CCS only" and "CCS + H2" are only $16 and $22 for each ton of reduction above that achieved in the "coal only" case, respectively (Figure 4). We do not observe significant increase in renewable capacity addition after applying these strict regulations on NG because the installed capacity of wind and photovoltaics (PV) already reaches the maximum permitted in 2035 under "coal + new gas." More renewable capacity will be added to the system if no renewable growth rate limits are applied (Figure S12). Adding additional renewable capacity principally reduces CCS retrofit capacity, which lowers average abatement costs but does not significantly reduce emissions further. Without the renewable growth limits, the H_2 blending requirement in the "CCS + H_2" scenario further promotes the addition of renewables and reduces peaker capacity relative to the "CCS only" scenario.

DISCUSSION

In this work, we investigate the potential impacts of EPA power plant emissions performance standards on power system operations and emissions by incorporating the complex operational constraints imposed by the rules for different classes of fossil-fueled generators into a detailed capacity expansion model. We observe significant CO_2 emissions reductions from 2035 to 2040 under the finalized rules. Emissions in 2040 reach 51% below 2022 emissions levels and 14% reductions in 2023–2040 cumulative emissions under our reference assumptions and 34%–74% below 2022 emissions levels (10%–21% cumulative emissions reduction) under a range of sensitivity analyses conducted on fuel prices, renewable resource availability, and tax credit treatment, demonstrating that the EPA regulations can substantially reduce power sector emissions across a range of plausible future conditions. The most significant reductions occur with high NG prices, positioning the EPA rules as an effective backstop against elevated emissions from prolonged operation of unabated coal-fired generators.

By isolating the impacts of the rules applied to different classes of fossil-fueled generators, we determine that coal retirement (as a result of regulation on coal-fired steam generators) contributes most to the emissions mitigation under the EPA's regulations (accounting for 70% of all reductions from the no regulations benchmark in 2040 under reference assumptions). Finalized regulations for new gas generators are primarily met by restricting average utilization rate (CF) to <40% to avoid more costly CCS requirements (97% of new NGCC plants are operated at a CF below 40%, and 3% are equipped with CCS in 2040). Although the utilization rate of coal significantly drops, CFs of existing NG plants increase and CFs of new NG plants decrease (Figure S7) because the final rules only regulate new gas generators. Therefore, regulations on new gas units further reduce emissions but at a relatively high average cost of abatement: $75 per ton of additional CO2 reductions vs. applying regulations only to existing coal generators. This *de facto* constraint on CFs for new, more efficient gas generators results in more overall new gas capacity utilized less frequently, raising the effective average cost of electricity from new gas plants and thus increasing reliance on less efficient existing gas generators.

Compared with the initial proposed rules, we find that the EPA's decision to delay finalization of regulations on existing large and baseload gas turbines yields only minimal negative emissions impacts, as the proposed rule for existing gas would have applied only to a small share of existing generating capacity and these units can comply with the proposed rule simply by operating at <40% CF annually. Additionally, given the high price of clean hydrogen, removing the H_2 co-firing requirement for gas generators in the proposed rule reduces average abatement costs. Because the NG fleets would be operating in a more efficient way with the finalized rules, we expect lower impacts on electricity prices compared with proposed rules (see average wholesale electricity prices in Figure S8).

To inform the EPA's development of future regulations on existing gas generators, we also assess several potential alternative rules to identify opportunities to increase the efficacy or efficiency of emissions regulations. Although it is worthwhile to explore more specific scenarios with varying retirement date requirements or CF thresholds for different categories, we believe that our comparison between proposed and finalized rules demonstrates the following impacts: (1) removing a coal subcategory that plans to retire by 2035 and needs to run at a CF below 20% and delaying the compliance date of coal CCS retrofit to 2032 would significantly increase emissions in early periods and (2) even with relaxed CF thresholds of baseload generators to cover more NG capacity, restricting operations only on new, efficient gas turbines would not mitigate emissions effectively and efficiently. Therefore, we model the extension of current EPA rules for new gas turbines to existing gas generators. Compared with finalized rules, extending equivalent standards for new baseload gas generators to existing *baseload* gas plants results in a 21% emissions reduction compared with current finalized rules in 2040, with an affordable abatement cost at \$12/tCO_2. However, we find that requiring *all* existing gas turbines (regardless of CF) to retrofit with CCS by 2035 does not significantly reduce emissions but further increases the "overbuild" of new gas turbines used at low utilization rates to avoid CCS requirements, making electricity generation much more expensive. Under alternative rules requiring (1) all non-peakers (CF >20%) to install CCS or (2) all non-peakers to install CCS *and* all peakers to co-fire 30% H_2, we find larger emissions reductions at relatively low incremental emissions abatement costs compared to "coal only." This potential rule would promote the use of CCS on higher utilization rate plants. Our results show that almost all CCS plants are running at an annual CF greater than 40% (with a capacity weighted average of 92%). By applying consistent standards to new and existing generators, this alternative would accelerate the retirement of inefficient generators, resulting in a capacity portfolio closer to that observed under an emissions cap, where the power system will achieve emissions targets in a most cost-effective way (e.g., using less inefficient NG-fired generators, Figure S13). Relative to a "CO_2 cap" case achieving an equivalent emissions reduction, current EPA rules increase the average abatement cost from \$3 to\$17/tCO_2. However, we find that extending CCS requirements to all non-peakers (and additionally H_2 co-firing requirements for peakers) increases average abatement costs only from \$6 to \$11/tCO_2 (or \$8 to \$16 with the peaker H_2 co-firing rule), because the two alternatives treat all NG plants similarly, while EPA rules would increase the utilization rate of old, inefficient turbines. These two alternative regulations also achieve the lowest overall emissions in 2040 and the largest 2023–2040 cumulative emissions reduction: 81% and 88% below 2022 emissions levels and 32% and 36% lower cumulative emissions, respectively.

In summary, we find that regulations on gas-fired generators should be carefully considered to avoid overly restricting the construction of new, efficient gas generators relative to existing gas-fired units. Applying stricter regulations to only one subcategory of gas turbines (new or existing) will potentially increase gas-fired generation from the other gas subcategory, not necessarily mitigating emissions cost effectively. The removal of H_2 co-firing requirements on all new gas generators from the proposed rules is a step toward this goal by reducing the utilization of less efficient existing generators. However, the lack of regulations on new non-baseload (CF $\leq$40%) generators still leads to many generators choosing to lower their utilization level to avoid CCS investment costs. Alternatively, applying consistent emissions regulations to a larger group of gas-fired generators regardless of vintage—such as requiring all plants with CF >20% to install CCS and all plants with CF $\leq$20% to co-fire 30% hydrogen by 2035—can level the playing field and increase the emissions mitigation efficacy and economic efficiency of the overall regulation (e.g., achieve larger emissions reductions and lower average mitigation costs).

With the inauguration of Donald Trump to a second term, the US EPA is likely to soon initiate rule-making to rescind regulations of GHG emissions from power plants and other sources (e.g., vehicles) and the federal government is expected to cease defending these rules from court challenges, as they did during President Trump's first term. However, the process of repealing or replacing the final EPA rules assessed herein will require a full administrative rule-making equivalent to the process that established the current regulations (or that replaced the earlier Obama-era CPP with Trump's Affordable Clean Energy Rule in 2019). This work can thus also provide a comprehensive and detailed estimate of the potential impacts of repealing these rules.

METHODS

Power system modeling

We analyzed the power system of the CONUS with input parameters based on EIA data (form EIA-860 [2022],[21] form EIA-860M [June 2023],[22] and form EIA-923 [2022][23]), with NG and coal accounting for 45% and 15% of total starting installed capacity, respectively (Figure S1). We included around 25,000 electricity generators that existed in the US power grid in 2022 (including both thermal and renewable resources). To improve computational tractability, we clustered existing generators into ~500 resource groups based on their fuel type, generator type, capacity size, heat rate, and location. Within each resource cluster, generators were treated as identical and shared the characteristics of the cluster average. We also included distributed solar in our model as a reduction in net demand at each transmission substation.[24] To consider transmission constraints, we divided the CONUS into 26 zones based on aggregations of the 64 regions used in the EPA's integrated planning model (IPM) and modeled 49 transmission paths connecting these zones to form the initial transmission network.[25] Each zone was treated as a balancing area (BA) with its own electricity demand, and we assumed transmission flows were unconstrained within each zone. However, the cost of connecting new wind and solar resources included estimated costs to interconnect renewable energy project areas to demand centers within each zone using a transmission routing and costing algorithm described in Patankar et al.[26] Figure S2 shows the study domain of this work. In all zones, we allowed building new generators (nuclear, NG turbines with and without CCS [NG w/wo CCS], hydrogen-ready turbines [H_2], onshore and offshore wind, solar PV, and battery storage).

We also modeled retrofitting of existing gas and coal generators with CCS or H_2 co-firing and existing coal plants to co-fire with NG. GenX optimizes battery storage duration (within a range of 1–10 h) for each model zone by considering charge/discharge power costs ($/kW) and energy storage capacity costs ($/kWh) separately. Fuel blend ratios for co-fired plants are optimized within the model (though they are subject to pertinent constraints from EPA regulations in each case). The model also co-optimizes interzonal transmission expansion. Interzonal transmission expansion costs represent estimated costs to expand high-voltage transmission between a pair of metropolitan statistical areas (MSAs) with >1 million population located in neighboring zones (or the largest MSA if none of that size are present), as well as to expand "backbone" transmission networks connecting any MSAs with population >1 million within each zone (if more than one is present in the zone).[26]

To determine what and when to build new generators or retire existing generators, we employed GenX,[15,16] a state-of-the-art open-source capacity expansion model that considers detailed power plant operational constraints to optimize the system operation and investment decisions in every planning period. We modeled 52 weeks of operations with hourly resolution to represent each planning period. All input data except for green hydrogen production demand (i.e., operational parameters of existing generators,[21,22] renewable energy potential,[17] transmission capacity,[25] zonal electricity demand,[27,28] and costs assumptions[20,29,30]) were prepared by PowerGenome,[31] an open-source software tool that combines data from the EPA, National Renewable Energy Laboratory (NREL), and Rapid Energy Policy Evaluation and Analysis Toolkit (REPEAT) to rapidly produce input data for electricity system planning models. Additionally, we included an exogenous regional H_2 production requirement that was met by optimized electrolyzer capacity and operations and assumed H_2 was available at gas generators at a specified fuel price. H_2 has to be produced by electrolysis powered by new renewable energy matched with supply at an hourly basis within the same model zone, as per Treasury Department guidance for the 45V hydrogen tax credit.[32] We obtained the regional H_2 demand and investment cost assumptions for electrolyzers from Haley et al..[33] We modeled key incentives provided by the IRA of 2022, particularly the production and investment tax credits for new carbon-free electricity, production tax credit for existing nuclear (modeled as preventing economic retirement through expiration in 2032), and the 45Q tax credit for CCS.[3] Electricity demand profiles and levels (from Jenkins et al.[17]) also accounted for impacts of IRA incentives on electrification of transportation and space and water heating. For model validation, we ran GenX with installed capacities and historical fuel prices from 2021 without any capacity expansion and optimized operations. Electricity generation shares by resource type were very close to historical data from the EIA (Figure S3), indicating that GenX reproduces realistic market dynamics, including capturing economic competition between coal and gas generators, and is thus suitable for this kind of analysis.

As the rules proposed by the EPA regulate emissions from fossil fuel-fired power plants from now to 2038, we investigated their impacts on the power system until 2040, modeling four periods, 2023–2025 (referred to in figures as the 2025 planning period), 2026–2030 (2030), 2031–2035 (2035), and 2036–2040 (2040). The rules set multiple dates for defining both the regulated categories and the compliance dates, making it computationally expensive to model every time point included in the rules. Thus, we used linear interpolation between two periods to approximately estimate the emissions trends within model periods. For example, to approximate annual emissions for 2026–2029, we assumed emissions linearly decreased/increased from our modeled 2025 levels to modeled 2030 levels. Using capacity outputs from the previous period as existing capacity in the system, the capacity expansion in each period was optimized sequentially ("myopic" mode). Unlike "perfect foresight," which makes decisions across the entire temporal domain at high computational costs, "myopic" mode minimizes annuitized capital investments and variable costs in every period but does not anticipate future periods when planning each stage. Thus, to ensure equivalent treatment of production subsidies, we modeled the 45Q credits, which were available at $85/t$CO_2$ for a 12-year period, as an equivalent NPV payment of $45/t$CO_2$ in 2022 USD in all scenarios except for "CCS 20-year lifetime," where a 20-year lifetime was assumed. Similarly, Similarly, the $22/MWh (in 2022 USD) production tax credit available for the first ten years of production of electricity from wind and solar PV is modeled as a NPV-equivalent payment of $9.7/MWh for wind and $9.3/MWh for solar, assuming a 30-year asset life.production tax credits provided for electricity from wind and solar are modeled as an NPV payment of $9.7 and $9.3/MWh, respectively, assuming a 30-year lifetime for both.

For a comparison with the existing power system in 2022, we used installed capacity and electricity generation of each EGU from form EIA-923 and calculated system emissions with average emissions rates for coal and NG, respectively.

Modeling EPA rules

The EPA allows generators to choose different compliance pathways to reduce emissions (i.e., CCS retrofit, reduce utilization level, or fuel co-firing), but those mitigation requirements vary by operational status and generator types. For example, the EPA's performance standard for existing coal-fired generators that would like to operate after 2039 is based on retrofitting to equip CCS from 2032, but the standard for coal-fired generators that would retire before 2039 is based on co-firing 40% NG (in heat input) starting from 2030. Therefore, we ran a benchmark case with GenX to determine the economic retirement period of all coal generators absent EPA regulations and applied different constraints to each coal unit based on this economic retirement schedule. The finalized EPA rules could be grouped into two categories ("coal" and "new gas") applying to existing coal-fired boilers and new combustion turbines, respectively. Figure 1 shows how those regulations are modeled in GenX. Regulations for existing NG-fired combustion turbines were included in the proposed rules, and these regulations varied by both nameplate capacity and CF.

To consider detailed regulations on different types of generators, we enhanced GenX by allowing generators to burn multiple fuels in one turbine (co-firing) and introducing more operational constraints (e.g., minimum co-fire level or maximum CF) to represent conditions set by the EPA regulations. See Table S1 for details. For CCS retrofit, we included reductions in net power outputs and increase in heat rates associated with the installation of post-combustion CCS at NGCCs. Other impacts of CCS on NGCC plant operational flexibility (e.g., startup hours, minimum power output, or ramp rates) were not modeled in GenX. As the installed capacity of CCS is limited due to high investment costs and NGCC-CCS plants are operating at an average CF greater than 90%, we expect that inclusion of flexibility constraints would have minimal impacts on modeled outcomes.

To calculate the average CO_2 mitigation cost under each scenario, we compared increases in annualized system costs and reductions in CO_2 emissions reductions relative to the "no regulations" case. We also calculated the average cost of incremental reductions relative to the "coal only" scenario. We also included sensitivity analyses on renewable growth rates, NG prices, coal prices, and tax credit treatment to understand how future uncertainties would affect the emissions reduction potential of the proposed rules (Figures S5 and S6).

Alternative strategies

In addition to rules proposed by the EPA, we included three groups of alternative mitigation strategies that had an emissions limit similar to modeled emissions from including all EPA rules ("CO_2 cap"), extended finalized EPA rules to existing gas-fired generators in the system ("final + baseload existing" and "final + all existing"), or explored alternative regulations for all gas turbines ("CCS only" and "CCS + H_2"). Table 1 provides a detailed description of these alternatives. All alternatives except for "CO_2 cap" applied the same regulations on coal as in the final EPA rules.

RESOURCE AVAILABILITY

Lead contact

Please contact the lead contact, Dr. Jesse D. Jenkins (jessejenkins@princeton.edu), for information related to the data and model used in this study.

Materials availability

This study did not generate new unique materials.

Data and code availability

The model, GenX, used in this study is available at GitHub: https://github.com/GenXProject/GenX.jl. The data for the power system in the United States were prepared by PowerGenome, which is also available at GitHub: https://github.com/PowerGenome/PowerGenome.

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AUTHOR CONTRIBUTIONS

Conceptualization, J.D.J.; methodology, J.D.J. and Q.L.; investigation, Q.L.; writing – original draft, Q.L.; writing – review & editing, J.D.J.

DECLARATION OF INTERESTS

J.D.J. serves as a scientific and technical advisor for MUUS Climate Partners and Energy Impact Partners, venture investors in early-stage decarbonization technologies; serves on the advisory board of Eavor Technologies, Rondo Energy, and Dig Energy and has an equity interest in each company; is a partner and co-owner of DeSolve LLC, a consultancy providing expertise in energy systems and decision support; and is also the co-host of the energy transition podcast SHIFT KEY published by Heatmap News.

SUPPLEMENTAL INFORMATION

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Supplemental information

US EPA's power plant rules reduce CO_2 emissions but can achieve more cost-efficient and deeper reduction by regulating existing gas-fired plants

Qian Luo and Jesse D. Jenkins

Supplemental Information

S1 Supplemental Figures

S1.1 Power system in GenX

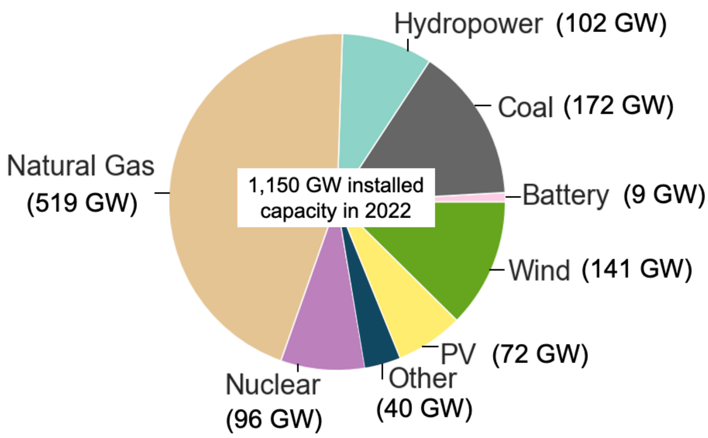

Fig. S1 Installed capacity by fuel type in the CONUS US in 2022.

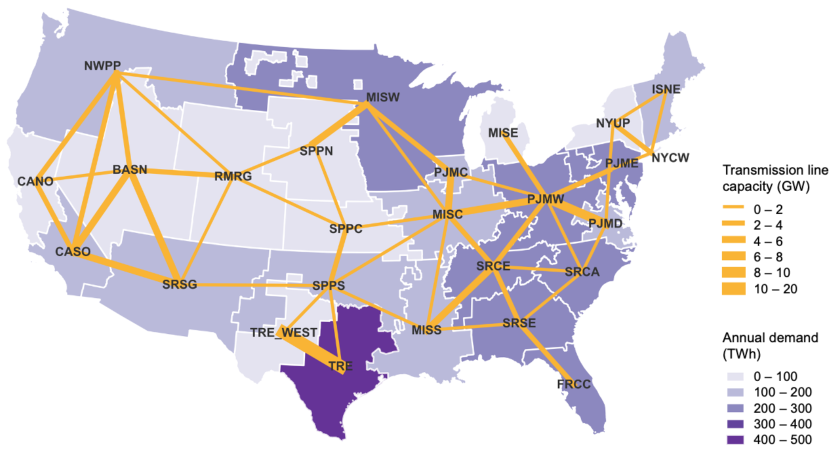

Fig. S2 Annual electricity demand in each zone and existing transmission capacity across zones in 2023.

S1.2 Proposed EPA rules

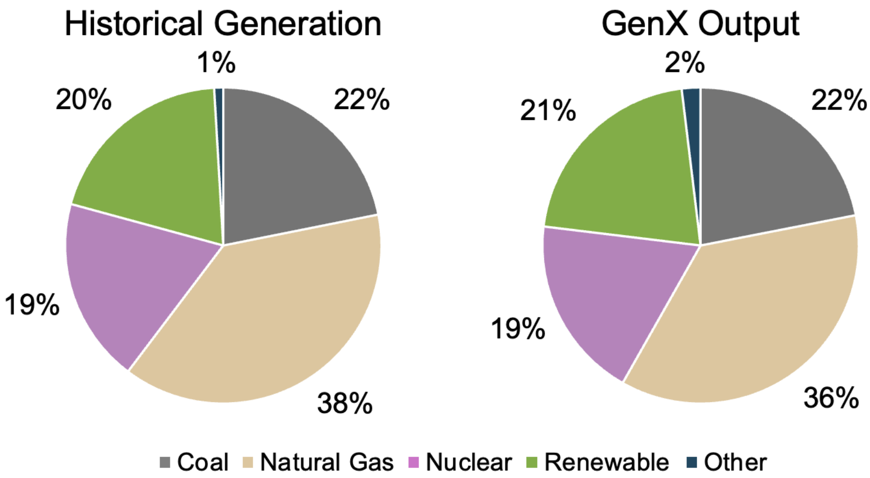

Fig. S3 Fuel mix of historical and GenX modeled electricity generation in 2021.

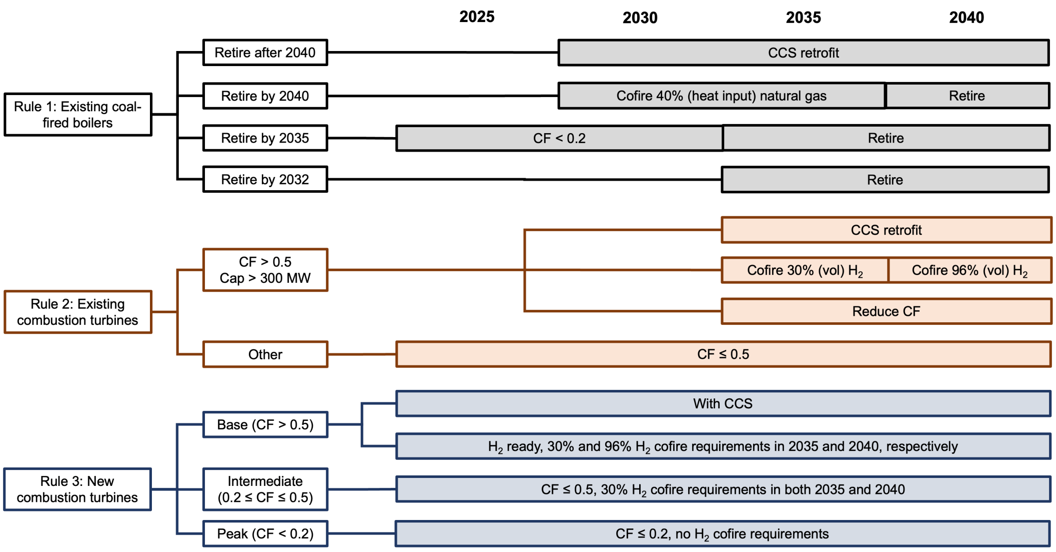

Fig. S4 CO_2 emission mitigation options from proposed EPA rules in each modeling period for different generator types in GenX.

S1.3 Assumptions used in sensitivity analysis

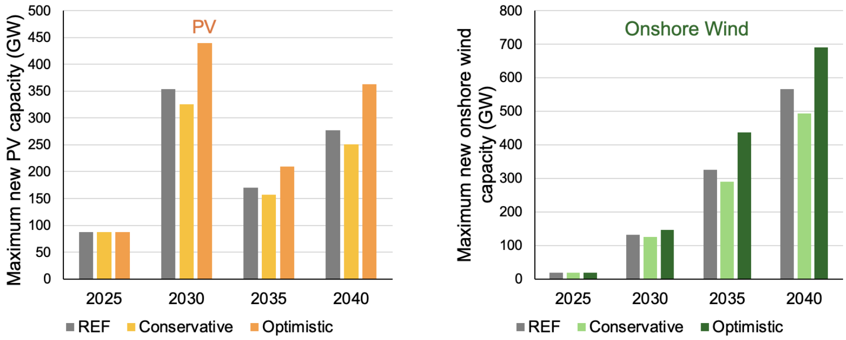

Fig. S5 Maximum annual addition of renewable energy allowed under different scenarios. Solar and onshore wind have the same annual growth rate limit. Values for 2025 are from EIA short-term energy outlook and identical across three scenarios[1]. Maximum PV capacity in 2035 is lower than that in 2030 because new PV added by 2030 is lower than 2030 maximum and 2035 maximum is determined by the growth rate and new capacity added in 2030.

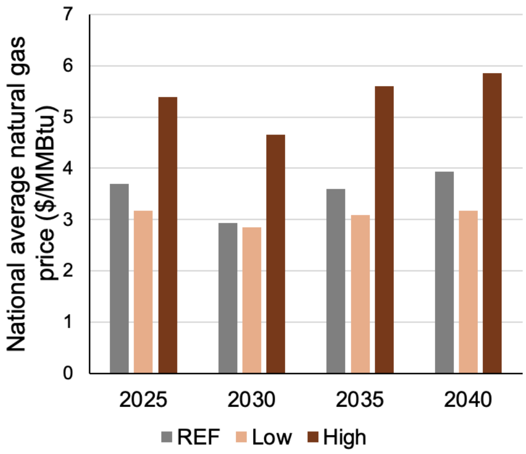

Fig. S6 National average natural gas prices under different scenarios.

S1.4 Additional results

S1.4.1 Proposed and finalized rules

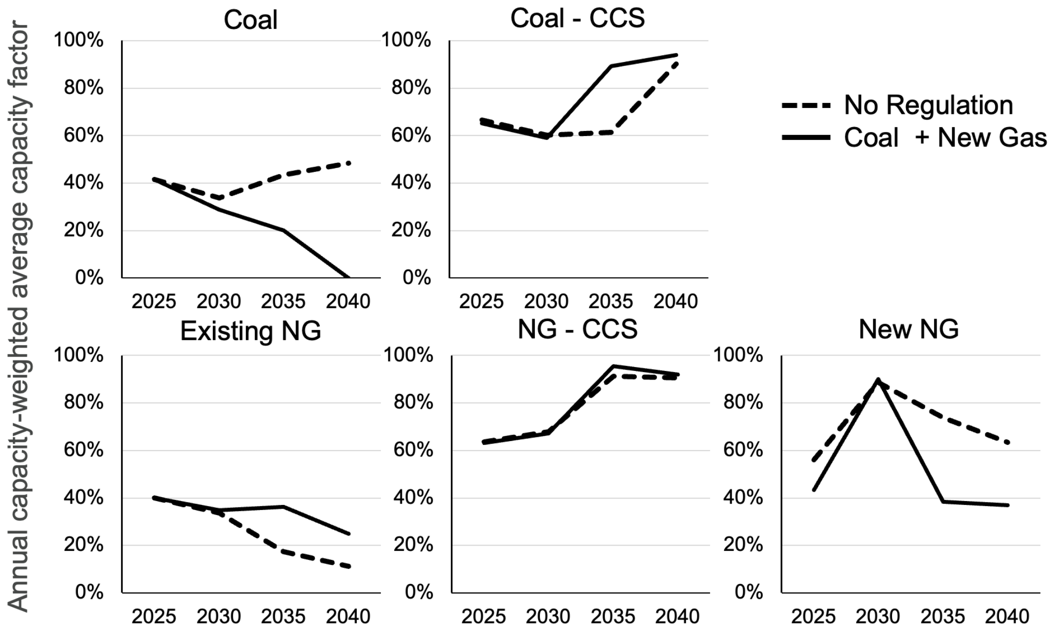

Fig. S7 Annual capacity-weighted average capacity factors of coal and natural gas power plants in each period.

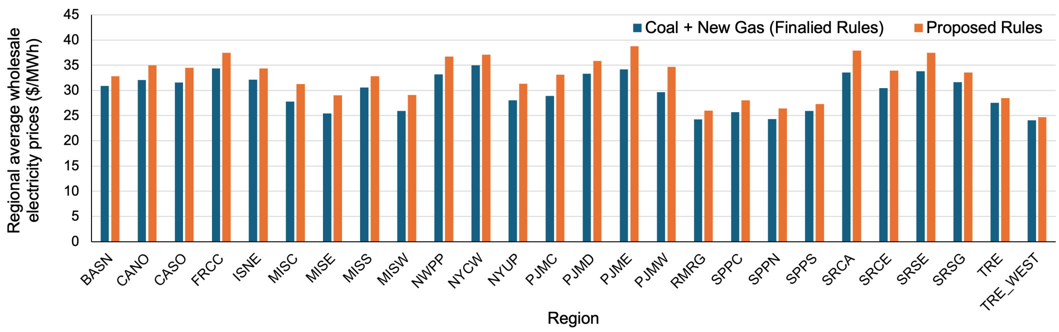

Fig. S8 Regional average wholesale electricity prices weighed by hourly regional demand.

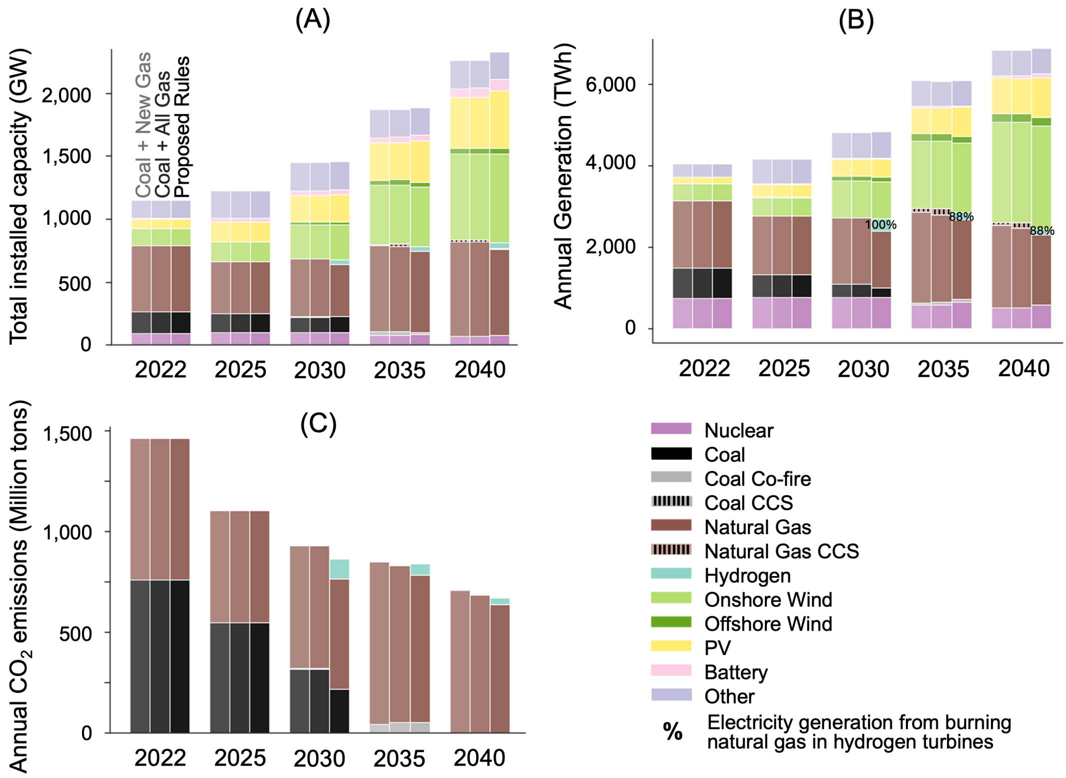

Fig. S9 Total installed capacity (A), electricity generation (B), and CO_2 emissions (C) by technology in each period. 2022 data is from EIA and other periods are modeling outputs.

S1.4.2 Sensitivity analysis

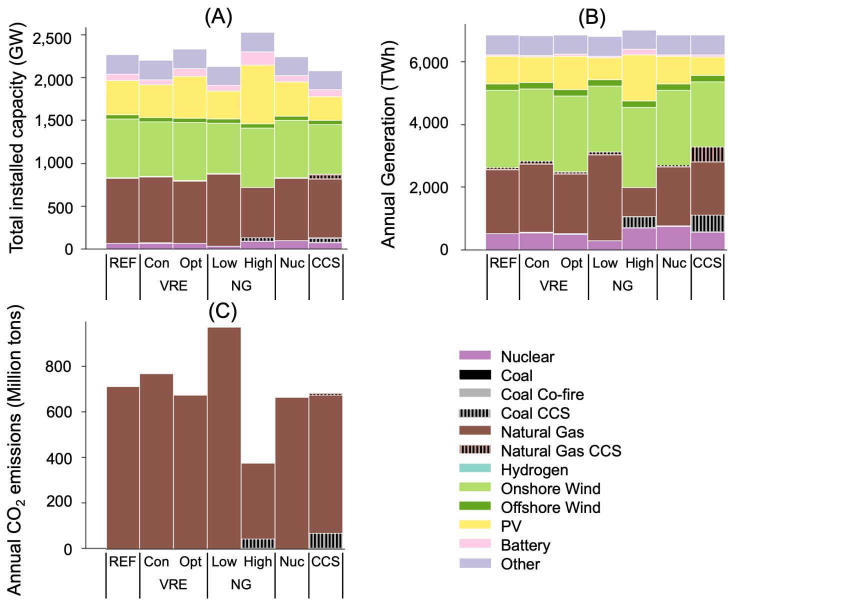

Fig. S10 Total installed capacity (A), electricity generation (B), and CO_2 emissions (C) by technology in 2040 under various uncertainty assumptions.

S1.4.3 Alternative strategies

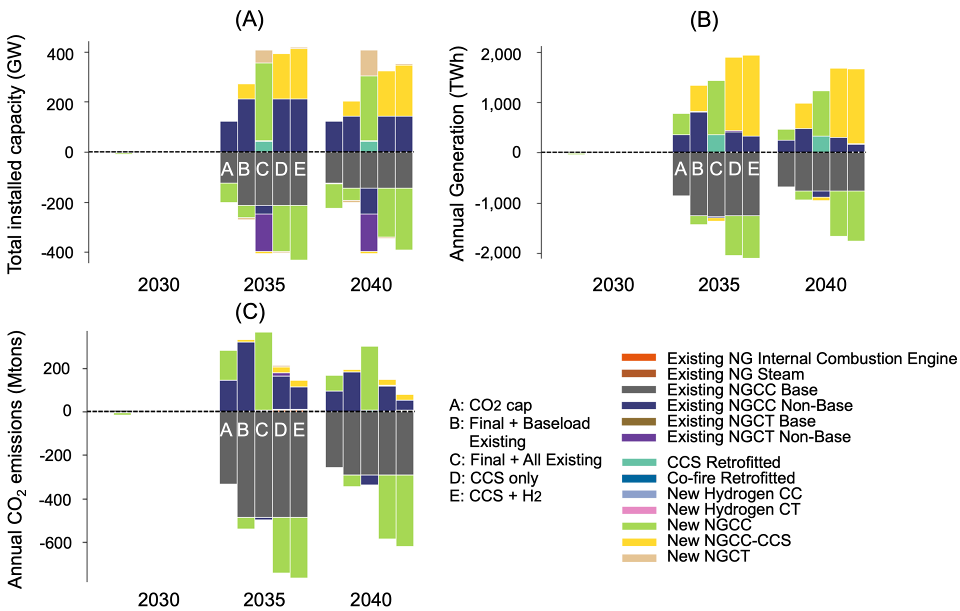

Fig. S11 Differences between the "Coal + New Gas" rule and alternative strategies in installed capacity (A), electricity generation (B), and CO_2 emissions (C) for natural gas-fired EGUs in each period. (Base: capacity factor $> 40\%$)

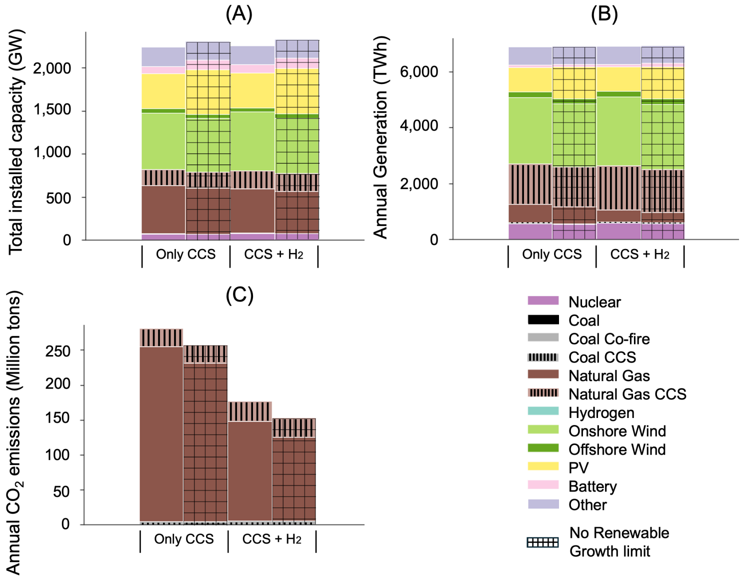

Fig. S12 Total installed capacity (A), electricity generation (B), and CO_2 emissions (C) by technology in 2040 under alternative strategies when there are no renewable growth limits.

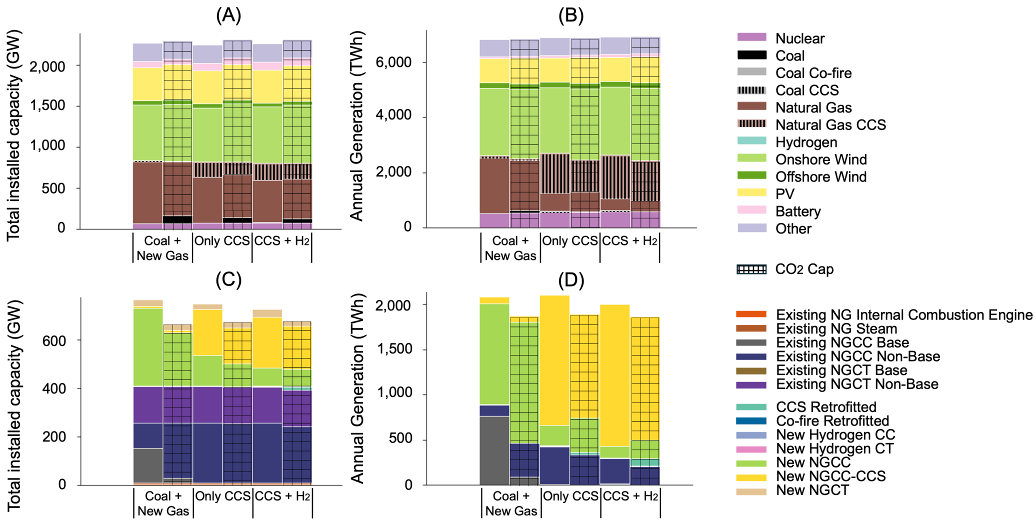

Fig. S13 Differences between the technology-specific rules and their corresponding "CO_2 Cap" cases in total installed capacity (A), total electricity generation (B), installed capacity for natural gas-fired EGUs (C), and electricity generation from natural gas-fired EGUs (D) in 2040. (Base: capacity factor > 40%)

S2 Supplemental Tables

Table S1 Additional operational constraints added to GenX to reflect the various compliance pathways from EPA rules.

Constraints	Equations
Multiple fuels in EGU e at hour h	$\sum_{f=1}^{Fuels} \frac{Fuel\,Consumption_{\mathrm{e,\ h,\ f}}}{Heat\,Rate_{\mathrm{e,\ f}}} = Power\,Output_{\mathrm{e,\ h}}$
Minimum co-fire requirement for fuel f in EGU e at hour h	$Fuel\,Consumption_{\mathrm{e,\ h,\ f}} \leq Min\,Cofire_{\mathrm{e,f}} \times \sum_{f=1}^{Fuels} Fuel\,Consumption_{\mathrm{e,\ h,\ f}}$
Utilization level limit for EGU e	$\sum_{h=1}^{8736} Power\,Output_{\mathrm{e,\ h}} \leq \sum_{h=1}^{8736} Capacity_{\mathrm{e}} \times Max\,Capacity\,Factor_{\mathrm{e}}$, $\sum_{h=1}^{8736} Power\,Output_{\mathrm{e,\ h}} \geq \sum_{h=1}^{8736} Capacity_{\mathrm{e}} \times Min\,Capacity\,Factor_{\mathrm{e}}$

Table S2 Assumptions of the compound annual growth rate (CAGR of for new wind and solar capacity[2].

Year	CAGR - REF	CAGR - Optimistic	CAGR - Conservative
2026 - 2035	18%	28%	14%
2036 - 2040	7.2%	7.2%	7.2%

Table S3 Average annual incremental emission reductions in four period compared across scenarios (million tons). Scenarios in the first column serve as the baseline for the comparison.

	Coal Only	Coal + New Gas (Final)	Final + Baseload Existing	CCS Only	CCS + H_2
No Regulations	567	708	1,006	1,578	1,772
Coal Only	-	141	439	1,010	1,204
Coal + New Gas	-	-	297	869	1,063
Final + Baseload Existing	-	-	-	572	766
CCS Only	-	-	-	-	194

* “Final + All Existing” is not included in the table as it has CCS requirements for all existing gas-fired EGUs and cannot work as a baseline for “CCS Only”, which sets CCS requirements for non-peakers. From “Final + Baseload Existing” to “Final + All Existing”, the average annual incremental emissions are 13 million tons.

Table S4 Average incremental abatement costs in four period compared across scenarios ($\$/tCO_2$). Scenarios in the first column serve as the baseline for the comparison.

	Coal Only	Coal + New Gas (Final)	Final + Baseload Existing	CCS Only	CCS + H_2
No Regulations	3	17	12	11	16
Coal Only	-	75	23	16	22
Coal + New Gas	-	-	-2	6	15
Final + Baseload Existing	-	-	-	10	22
CCS Only	-	-	-	-	56

* "Final + All Existing" is not included in the table as it has CCS requirements for all existing gas-fired EGUs and cannot work as a baseline for "CCS Only", which sets CCS requirements for non-peakers. From "Final + Baseload Existing" to "Final + All Existing", the incremental abatement cost is $\$623/tCO_2$.

Supplemental References

[1] U.S. Energy Information Administration: Short-Term Energy Outlook. Technical report (2023). https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf/ Accessed 12 Aug 2024

[2] Jenkins, J.D., Mayfield, E.N., Farbes, J., Schivley, G., Patankar, N., Jones, R.: The Impacts of the Inflation Reduction Act and the Infrastructure Investment and Jobs Act (Version: July 14, 2023). Technical report (2023). 10.5281/zenodo.8087805 Accessed 12 Feb 2024