Regulatory Impact Analysis for the Final Revised Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone NAAQS

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Regulatory Impact Analysis for the Final Revised Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone NAAQS

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Overview

This action is taken in response to the United States Court of Appeals for the District of Columbia Circuit's (D.C. Circuit) September 13, 2019 remand of the Cross-State Air Pollution Rule (CSAPR) Update.[1] The CSAPR Update finalized Federal Implementation Plans (FIPs) for 22 states to address their interstate pollution-transport obligations under the Clean Air Act (CAA) for the 2008 ozone National Ambient Air Quality Standards (NAAQS).[2] The D.C. Circuit found that the CSAPR Update, which was published on October 26, 2016 as a partial remedy to address upwind states' obligations prior to the 2018 Moderate area attainment date under the 2008 ozone NAAQS, was unlawful to the extent it allowed those states to continue their significant contributions to downwind ozone problems beyond the statutory dates by which downwind states must demonstrate their attainment of the air quality standards. This rule will resolve 21 states' outstanding interstate ozone transport obligations with respect to the 2008 ozone NAAQS. [3]

This action finds that for 9 of the 21 states with remanded FIPs (Alabama, Arkansas, Iowa, Kansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin), their projected 2021 ozone season nitrogen oxides (NOx) emissions do not significantly contribute to a continuing downwind nonattainment and/or maintenance problem; therefore the CSAPR Update fully addresses their interstate ozone transport obligations with respect to the 2008 ozone NAAQS. This action also finds that for the 12 remaining states (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia), their projected 2021 ozone season NOx emissions significantly contribute to downwind states' nonattainment and/or maintenance problems for the 2008 ozone NAAQS.

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[1] *Wisconsin v. EPA*, 938 F.3d 303 (D.C. Cir. 2019). This action will also have the effect of addressing the outstanding obligations that resulted from the D.C. Circuit's vacatur of the CSAPR Close-Out in *New York v. EPA*, 781 Fed. App'x 4 (D.C. Cir. 2019).

[2] The 2008 ozone NAAQS is an 8-hour standard that was set at 75 parts per billion (ppb). See 73 FR 16436 (March 27, 2008).

[3] In the CSAPR Update, EPA found that the finalized Tennessee emissions budget fully addressed Tennessee's good neighbor obligation with respect to the 2008 ozone NAAQS. As such, Tennessee is not considered in this rule, and the number of states included is reduced from 22 to 21 states.

EPA is creating an additional geographic group and ozone season trading program comprised of these 12 upwind states with remaining linkages to downwind air quality problems in 2021. This new group, Group 3, will be covered by a new CSAPR NO_X Ozone Season (May 1 – September 30) Group 3 trading program and will no longer be subject to Group 2 budgets. Aside from the removal of the 12 covered states from the current Group 2 program, this rule leaves unchanged the budget stringency and geography of the existing CSAPR NO_X Ozone Season Group 1 and Group 2 trading programs. The electric generating units (EGUs) covered by the FIPs and subject to the budget are fossil-fired EGUs with >25 megawatt (MW) capacity.

ES.1 Identifying Needed Emissions Reductions and Description of the Remedy

To reduce interstate emission transport under the authority provided in CAA section 110(a)(2)(D)(i)(I), this rule further limits ozone season NO_X emissions from EGUs in 12 states using the same framework used by EPA in developing the CSAPR (the interstate transport framework). The interstate transport framework provides a 4-step process to address the requirements of the good neighbor provision for ground-level ozone and fine particulate matter ($PM_{2.5}$) NAAQS: (1) identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (2) determining which upwind states contribute to these identified problems in amounts sufficient to “link” them to the downwind air quality problems (i.e., here, an amount of contribution equal to or greater than 1 percent of the NAAQS); (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind, implementing the necessary emissions reductions through enforceable measures. In this action, EPA applies this 4-step interstate transport framework to respond to the D.C. Circuit’s remand and revise the CSAPR Update with respect to the 2008 ozone NAAQS.

The remedy that emerges from the 4-step interstate transport framework here are state emissions budgets for EGUs implemented as an interstate cap-and-trade program.[4] This

[4] Section X.J. *Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* in the preamble describes EPA’s ongoing response to the President’s environmental justice commitments.

regulatory impact analysis (RIA) evaluates how the EGUs covered by the rule are expected to reduce their emissions in response to the requirements and flexibilities provided by the remedy implemented by the Revised CSAPR Update and the estimated benefits, costs, and impacts of doing so. The rule sets EGU ozone season NO_X emissions budgets (allowable emission levels) for 2021 and future years. EPA implements these reductions through FIPs in any state that does not have an approved good neighbor SIP by the date this action is finalized. Furthermore, under the FIPs, affected EGUs would participate in the CSAPR NO_X ozone-season allowance trading program. The allowance trading program essentially converts the EGU NO_X emissions budget for each of the 12 states subject to the FIP into a limited number of NO_X ozone-season allowances that, on a tonnage basis, equal the state's ozone season emissions budget. Starting in 2021, emissions from affected EGUs in the 12 states cannot exceed the sum of emissions budgets but for the ability to use banked allowances from previous years for compliance. The seasonal budgets decline in 2022, 2023 and 2024. No further reductions in budgets occur after 2024, and budgets remain in place for future years. Furthermore, emissions from affected EGUs in a particular state are subject to the CSAPR assurance provisions, which require additional allowance surrender penalties (a total of 3 allowances per ton of emissions) on emissions that exceed a state's CSAPR NO_X ozone season assurance level, or 121 percent of the states' emissions budget. EPA is creating a limited initial bank of allowances for use in the new Group 3 trading program by converting allowances banked in 2017-2020 under the existing Group 2 trading program at a formula-based conversion ratio. The target bank amount is based on the sum of the states' "variability limits" – that is, the amounts by which emissions from a given state's units can exceed the state's emission budget before incurring a penalty surrender ratio.

For the Revised CSAPR Update, the EGU ozone season NO_X budgets for each state reflect widely available EGU NO_X reduction strategies including optimizing existing SCR and SNCR, as well as installing state-of-the-art combustion controls, at an estimated representative cost of $1,800 per ton. Furthermore, this RIA analyzes more and less stringent regulatory control alternatives at estimated representative NO_X control costs of $9,600 per ton and $500 per ton, respectively. Table ES-1 shows the illustrative EGU NO_X ozone season emission budgets that are evaluated in this RIA.

All three scenarios are illustrative in nature, and the budgets included in the Revised CSAPR Update scenario differ slightly from the budgets finalized in this rule. That is because subsequent to completing the analysis of these three scenarios, EPA decided to set the budgets using a different approach than assumed for the analysis. In particular, the modeling presented in the RIA assumes that SNCR optimization is available in 2022, whereas the final budgets confirm that SNCR optimization is available in 2021. The estimated incremental emission reductions would be 1,163 tons if EPA had used the actual 2021 budgets, or a 1.1 percent tightening in the modeled budget across the Group 3 states. The choice of 2021 or 2022 for the initial year of SNCR optimization is an exogenous input into the analysis. EPA finds that the three illustrative regulatory control alternatives presented in this RIA provide a reasonable approximation of the impacts of the final rule, as well as an evaluation of the relative impacts of two regulatory alternatives. This finding is supported by an analysis of the costs and impacts (but not the benefits) of the final Revised CSAPR Update emission budgets that assumes 2021 for the initial year of SNCR optimization and provided in the docket for this rulemaking.

Table ES-1. Illustrative NO_X Ozone Season Emission Budgets (Tons) Evaluated

	Final Rule				
State	**2021**	**2022**	**2023**	**2024**	**2025**
Illinois	9,198	9,102	8,179	8,059	8,059
Indiana	13,085	12,582	12,553	9,564	9,564
Kentucky	15,307	14,051	14,051	14,051	14,051
Louisiana	15,389	14,818	14,818	14,818	14,818
Maryland	1,499	1,266	1,266	1,348	1,348
Michigan	12,732	12,290	9,975	9,786	9,786
New Jersey	1,253	1,253	1,253	1,253	1,253
New York	3,416	3,416	3,421	3,403	3,403
Ohio	9,690	9,773	9,773	9,773	9,773
Pennsylvania	8,379	8,373	8,373	8,373	8,373
Virginia	4,614	3,897	3,980	3,663	3,663
West Virginia	13,686	12,884	12,884	12,884	12,884
Total	108,248	103,703	100,525	96,974	96,974
	Less-Stringent Alternative				
State	**2021**	**2022**	**2023**	**2024**	**2025**
Illinois	9,348	9,348	8,393	8,272	8,272
Indiana	15,677	15,206	15,179	12,083	12,083
Kentucky	15,606	15,606	15,606	15,606	15,606
Louisiana	15,430	15,430	15,430	15,430	15,430
Maryland	1,501	1,267	1,267	1,350	1,350
Michigan	13,126	12,688	10,386	10,188	10,188
New Jersey	1,346	1,346	1,346	1,346	1,346
New York	3,463	3,463	3,468	3,450	3,450
Ohio	15,487	15,569	15,569	15,569	15,569
Pennsylvania	11,807	11,806	11,806	11,806	11,806
Virginia	4,661	4,270	4,357	4,021	4,021
West Virginia	15,017	15,017	15,017	15,017	15,017
Total	122,468	121,016	117,822	114,138	114,138

More-Stringent Alternative[5]

State	2021	2022	2023	2024	2025
Illinois	9,198	9,102	8,179	6,891	6,891
Indiana	13,085	12,582	12,553	8,430	8,430
Kentucky	15,307	14,051	14,051	9,775	9,775
Louisiana	15,389	14,818	14,818	12,622	12,622
Maryland	1,499	1,266	1,266	1,168	1,168
Michigan	12,732	12,290	9,975	7,344	7,344
New Jersey	1,253	1,253	1,253	1,257	1,257
New York	3,416	3,416	3,421	3,297	3,297
Ohio	9,690	9,773	9,773	9,222	9,222
Pennsylvania	8,379	8,373	8,373	7,851	7,851
Virginia	4,614	3,897	3,980	3,184	3,184
West Virginia	13,686	12,884	12,884	10,568	10,568
Total	108,248	103,703	100,525	81,609	81,609

ES.2 Baseline and Analysis Years

The rule sets forth the requirements to eliminate states' significant contribution to downwind nonattainment or interference with maintenance of the 2008 ozone NAAQS. To develop and evaluate control strategies for addressing these obligations, it is important to first establish a baseline projection of air quality and electricity sector and related fuel market conditions in the analysis period, taking into account currently on-the-books Federal regulations, substantial Federal regulatory proposals, enforcement actions, state regulations, population, expected electricity demand growth, and where possible, economic growth.[6] Establishing this baseline for the analysis then allows us to estimate the incremental costs and benefits of the additional emissions reductions that will be achieved by the rule.

[5] For the illustrative purposes in this RIA, EPA's analytical technique for assessing the more stringent alternative presents emission reduction values incremental to the final rule's stringency prior to 2025. This does not reflect a determination that new SCR controls could be installed on a fleetwide basis before the 2025 ozone season. See sections VI.B.1, C.1, and D.1 of the preamble for further discussion.

[6] The technical support document (TSD) for the 2016v1 emissions modeling platform titled *Preparation of Emissions Inventories for 2016v1 North American Emissions Modeling Platform* is included in the docket for this rule. The TSD includes additional discussion on mobile source rules included in the baseline. The future year onroad emission factors account for changes in activity data and the impact of on-the-books rules that are implemented into MOVES2014b. These rules include the Light Duty Vehicle GHG Rule for Model-Year 2017-2025 and the Tier 3 Motor Vehicle Emission and Fuel Standards Rule. Local inspection and maintenance (I/M) and other onroad mobile programs are included, such as California LEVIII, the National Low Emissions Vehicle (LEV) and Ozone Transport Commission (OTC) LEV regulations, local fuel programs, and Stage II refueling control programs. Regulations finalized after the year 2014 are not included, such as the Safer Affordable Fuel Efficient (SAFE) Vehicles Final Rule for Model Years 2021-2026 and the Final Rule for Phase 2 Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles.

The analysis in this RIA focuses on benefits, costs and certain impacts from 2021 through 2040. We focus on 2021 because it is by the 2021 ozone season, corresponding with the 2021 Serious area attainment date, that significant contribution from upwind states' must be eliminated to the extent possible. It is also the first year in which some EGU NOx mitigation technologies are available. In addition, impacts for 2022 to 2025 are important as these years reflect the years in which additional NOx mitigation technologies are first available. Since retrofits are assumed to have a 15-year book life and the budgets remain in place for future years after 2025, costs and benefits from installation may persist beyond 2025. In order to capture these streams, the RIA also provides costs through 2040.

Presenting estimated benefits, costs, and certain impacts in 2025 reflects the time needed to make these retrofits on a regional scale and reflects full implementation of the policy. Additional benefits and costs are expected to occur after 2025 as EGUs subject to this rule continue to comply with the tighter allowance budget, which is below their baseline emissions, and these costs and benefits are reflected in the estimates through 2040 provided in this RIA.

ES.3 Emissions and Air Quality Modeling

The air quality spatial fields for this rule were constructed using the method and air quality modeling data developed to support the RIA for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (U.S. EPA 2019), also referred to the Affordable Clean Energy (ACE) rule.[7] The foundational data from this approach includes the ozone contributions from EGU emissions in each state based on the 2023 ACE EGU state-sector sector contribution modeling and the 2023 emissions for coal and non-coal fired EGUs that were input to that modeling.[8]

The air quality modeling used in the ACE analysis included annual model simulations for a 2011 base year and a 2023 future year to provide hourly concentrations of ozone and primary and secondarily formed $PM_{2.5}$ component species (*e.g.*, sulfate, nitrate, ammonium, elemental

[7] Additional details on the modeling and methodology for developing spatial fields of air quality for EGU control strategies are provided in Appendix 3A.
[8] The 2023 emissions used for the ACE modeling were derived from the 2011-based emissions platform whereas the emissions used in the air quality modeling to project ozone design values and contributions for this final rule were based on the more recent 2016 platform.

carbon (EC), organic aerosol (OA), and crustal material[9]) for both years nationwide. The photochemical modeling results for 2011 and 2023, in conjunction with modeling to characterize the air quality impacts from groups of emissions sources (*i.e.*, source apportionment modeling) and emissions data for the baseline and regulatory control alternatives, were used to construct the air quality spatial fields that reflect the influence of emissions changes between the baseline and the regulatory control alternatives.

The air quality model simulations (*i.e.*, model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx) f. Our CAMx nationwide modeling domain (*i.e.*, the geographic area included in the modeling) covers all lower 48 states plus adjacent portions of Canada and Mexico using a horizontal grid resolution of 12 x 12 km.

To estimate ozone-related benefits in 2021 and 2024 EPA applied the approach used in the ACE final RIA using as input the ozone season EGU NOx emissions (tons) for the 2021 and 2024 baseline along with emissions for the rule and each of the two other regulatory control alternatives. These emissions were applied using this approach and source apportionment data to produce spatial fields of the May-September seasonal average MDA8 ozone and the April-October seasonal average MDA1 ozone concentrations as described in Chapter 3.[10] Similarly, to estimate $PM_{2.5}$ benefits in 2024 EPA applied the same approach using as input the non-ozone season EGU NOx emissions (tons) for the 2024 baseline along with emissions for the rule and each of the two other regulatory control alternatives.[11] To estimate benefits in the years beyond 2024, the same 2021 and 2024 air quality surfaces were linearly extrapolated or interpolated to 2040.[12] NOx reductions in the ozone season provide minimal $PM_{2.5}$ benefits since $PM_{2.5}$ nitrate concentrations, which result from conversion of NOx emissions to nitrate, are minimal during the warmer temperatures during the ozone season. Conversely, the conversion of nitrates to

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[9] Crustal material refers to metals that are commonly found in the earth's crust such as Aluminum, Calcium, Iron, Magnesium, Manganese, Potassium, Silicon, Titanium and the associated oxygen atoms.

[10] MDA8 is defined as maximum daily 8-hour average ozone concentration, and MDA1 is defined as the maximum daily 1-hour ozone concentration.

[11] See Chapter 5, section 5.2.1.2 *Calculating Counts of Air Pollution Effects Using the Heath Impact Function* for additional discussion. We use BenMAP-CE to quantify individual risk and counts of estimated premature deaths and illnesses attributable to photochemical modeled changes in summer season average ozone concentrations for the year 2021, and summer season average ozone concentrations and annual mean $PM_{2.5}$ for the year 2024 using a health impact function.

[12] Ozone air quality was modeled in 2021 and 2024, while the formation of $PM_{2.5}$ was modeled only in 2024. This assumes that ozone and $PM_{2.5}$ formation reaches a steady state beyond 2024, which may or may not be the case particularly the further out beyond 2024.

$PM_{2.5}$ is much greater in cooler (non-ozone season) months, and thus it becomes worthwhile to estimate $PM_{2.5}$ benefits from NOx reductions in those months. As there no expected NOx emissions changes outside of the ozone season in 2021, $PM_{2.5}$ concentrations are not evaluated for this model year. The changes in emissions of SO_2 and directly emitted $PM_{2.5}$were partially analyzed for this rule as described in Chapter 4. In particular, EPA did not analyze changes in emissions due to generation shifting for either SO_2 or $PM_{2.5}$ because the majority of the reductions associated with this rulemaking are tied to the operation of SCR and SNCR controls (which do not affect SO_2 emission rates) and state of the art combustion controls (which have a minimal impact on SO_2 emission rates). Additionally in order to meet the court-ordered timeline for this rulemaking EPA prioritized fully capturing the impact of reductions from generation shifting on NOx and CO_2, but did not account for the relatively small amount of SO_2 and primary PM emissions reductions that would likely occur due to generation shifting. Hence total benefits could be higher than those reported in this RIA.

ES.4 Control Strategies and Emissions Reductions

Before undertaking power sector analysis to evaluate compliance with the regulatory control alternatives, EPA first considered available EGU NO_X mitigation strategies that could be implemented for the upcoming ozone season (i.e., the 2021 ozone season). EPA considered all widely-used EGU NO_X control strategies: optimizing NO_X removal by existing, operational selective catalytic reduction (SCRs) and turning on and optimizing existing idled SCRs;[13] optimizing existing idled selective non-catalytic reduction (SNCRs); installation of (or upgrading to) state-of-the-art NO_X combustion controls; shifting generation to units with lower NO_X emission rates; and installing new SCRs and SNCRs. Similarly, as proposed, EPA determined that the power sector could implement most of these NO_X mitigation strategies, except installation of state-of-the-art NO_X combustion controls and new SCRs or SNCRs, for the 2021 ozone-season.

The EGU NO_X mitigation strategies that are assumed to operate or are available to reduce NO_X in response to each of the regulatory control alternatives are shown in Table ES-2. EPA

[13] Units may choose to idle SCRs and SNCRs in order to avoid fixed operation and maintenance (FOM) and variable operation and maintenance (VOM) costs such as auxiliary fan power, catalyst costs, and additional administrative costs (labor), depending on the prevailing CSAPR allowance price for those units otherwise not required to attain a NOx emission rate that would require operating their SCRs and SNCRs more intensively.

analyzed ozone-season NO_X emission reductions and the associated costs to the power sector of implementing the EGU NO_X ozone-season emissions budgets in each of the 12 states using the Integrated Planning Model (IPM) and its underlying data and inputs as well as certain costs that are estimated outside the model but use IPM inputs for their estimation. This analysis is also used to identify changes in other air pollutants from the power sector that arise as a consequence of complying with the budgets.

Table ES-2. NO_X Mitigation Strategies Represented in Modeling of the Regulatory Control Alternatives

Regulatory Control Alternative	NO_X Controls Implemented
Less Stringent Alternative	(1) Shift generation to minimize costs (costs estimated within IPM)
Final Rule	(All controls above) (2) Fully operating existing SCRs to achieve 0.08 lb/MMBtu NOx emission rate (costs estimated outside IPM) (3) Turn on idled SCRs (costs estimated outside IPM) and fully operate akin to (2) (4) Fully operate existing SNCRs (costs estimated outside IPM) (5) Install state-of-the-art combustion controls.
More Stringent Alternative	(All controls above) (6) In 2025, impose state emission limits commensurate with installation of new SCRs on units without such controls. However, additional SCRs controls are not a least-cost compliance strategy. (costs estimated within IPM)

For the NO_X controls identified in Table ES-2, under the rule and the more stringent alternative, 47 units, not already doing so in 2019, are projected to fully operate existing SCRs, 4 units are projected to turn on idled SCRs, and 29 units are projected to fully operate existing SNCRs. Under the less stringent alternative, no units are projected to either fully operate existing SNCRs, SCRs or turn on idled SCRs. Under the rule and the more stringent alternative, 10 units are projected to install state-of-the-art combustion controls, and under the less stringent alternative no units are projected to install state-of-the-art combustion controls. The book-life of the controls is assumed to be 15 years. Under the rule, the more stringent alternative, and the less stringent alternative, no units are projected to install new SCRs.[14] The book-life of the new SCRs is assumed to be 15 years. For additional details, see the EGU NO_X Mitigation Strategies Final Rule TSD.

[14] In the RIA for the proposed rule, units were exogenously forced to install SCR controls in IPM. In the modeling for the final rule, the choice to install SCR controls was endogenous to the model, and no incremental SCR installations occurred, with the model relying on greater levels of generation shifting instead.

Table ES-3 shows the emissions reductions expected from the rule in 2021, 2025, 2030, 2035, and 2040 as well as the more and less stringent alternatives analyzed.

Table ES-3. Estimated 2021, 2025, 2030, 2035, and 2040[a] EGU Emissions Reductions in the 12 States of NOx, SO_2, and CO_2 and More and Less Stringent Alternatives (Tons)[b]

2021	Final Rule	More Stringent Alternative	Less Stringent Alternative
NOx (annual)	16,000	16,000	2,000
NOx (ozone season)	16,000	16,000	2,000
SO_2 (annual)	*	*	*
CO_2 (annual, thousand metric)	--	--	--
2025			
NOx (annual)	21,000	37,000	2,000
NOx (ozone season)	19,000	34,000	2,000
SO_2 (annual)	*	*	*
CO_2 (annual, thousand metric)	5,000	14,000	4,000
2030			
NOx (annual)	16,000	27,000	2,000
NOx (ozone season)	13,000	25,000	2,000
SO_2 (annual)	*	*	*
CO_2 (annual, thousand metric)	8,000	19,000	6,000
2035			
NOx (annual)	15,000	26,000	2,000
NOx (ozone season)	13,000	25,000	2,000
SO_2 (annual)	*	*	*
CO_2 (annual, thousand metric)	8,000	19,000	6,000
2040			
NOx (annual)	14,000	25,000	2,000
NOx (ozone season)	13,000	24,000	2,000
SO_2 (annual)	*	*	*
CO_2 (annual, thousand metric)	4,000	13,000	3,000

[a] The 2021-2040 emissions reductions estimates are based on IPM projections for CO_2 and engineering analysis for annual and ozone season NOx. SO_2 and $PM_{2.5}$ emissions were only partially analyzed. IPM was run for the following years: 2021, 2023, 2025, 2030, 2035, 2040, 2045 and 2050. For more information, see Chapter 4 and the Ozone Transport Policy Analysis Final Rule TSD.
[b] NO_x emissions are reported in English (short) tons; CO_2 is reported in metric tons.
*There are no annual SO_2 and $PM_{2.5}$ emissions reductions that come from turning on SCRs and SNCRs assuming that nothing else changes, but EPA did not analyze the effects on SO_2 and direct PM that may come from shifting power generation, for example from coal-fired power plants to gas-fired or other types of power plants. EPA does expect some changes in SO_2 and $PM_{2.5}$ emissions due to shifting of power generation.

The results of EPA's analysis show that, with respect to compliance with the EGU NO_X emission budgets in 2021, maximizing the use of existing operating SCRs provides the largest amount of ozone season NO_X emission reductions (47 percent, affecting 47 units), and turning on idled SCRs produces an additional 37 percent (affecting 4 units) of the total ozone season NO_X reductions. Generation shifting primarily from coal to gas generation (16 percent) makes up the remainder of the ozone season NO_X reductions. EPA relied on Engineering Analysis to account for changes in NOx (annual and ozone season), SO_2, and direct PM. While this approach captures the impact of generation shifting for NOx emissions, it does not fully capture the impact of generation shifting for SO_2 and PM in complying with the Revised CSAPR Update budgets. Additionally in order to meet the court-ordered timeline for this rulemaking EPA prioritized fully capturing the impact of reductions from generation shifting on NOx and CO_2, but did not account for the relatively small amount of SO_2 and primary PM emissions reductions that would likely occur due to generation shifting. Hence total benefits could be higher than those reported in this RIA. EPA relied on IPM estimates to capture changes in CO_2 emissions, which fully account for the impact of generation shifting.

If EPA were to have included SNCR optimization in 2021, with respect to compliance with the EGU NOx emission budgets in 2021, maximizing the use of existing operating SCRs provides the largest amount of ozone season NOx emission reductions (44 percent, affecting 47 units), turning on idled SCRs produces an additional 35 percent (affecting 4 units) of the total ozone season NOx reductions, and fully operating existing SNCRs produces an additional 6 percent of reductions (affecting 29 units). Generation shifting primarily from coal to gas generation (15 percent) makes up the remainder of the ozone season NO_X reductions.

ES.5 Cost Impacts

The estimates of the changes in the cost of supplying electricity for the regulatory control alternatives are presented in Table ES-4. Since the rule does not result in any additional recordkeeping, monitoring or reporting requirements, the costs associated with compliance with monitoring, recordkeeping, and reporting requirements are not included within the estimates in this table.

There are several notable aspects of the results presented in Table ES-4. The most notable result is that the estimated annual compliance cost for the less stringent alternative is negative (i.e., a cost reduction) in 2025, although this regulatory control alternative reduces NO_X emissions by 2,000 tons as shown in Table ES-3. While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given the assumption of perfect foresight in IPM. IPM's objective function is to minimize the discounted net present value (NPV) of a stream of annual total cost of generation over a multi-decadal time period. For example, with the assumption of perfect foresight it is possible that on a national basis within the model the least-cost compliance strategy may be to delay a new investment or economic retirement that was projected to occur sooner in the baseline. Such a delay could result in a lowering of annual cost in an early time period and increase it in later time periods. Since the less-stringent alternative is designed to include only generation shifting, it does not necessitate full operation of existing controls, or installation of new controls, leading to a negative annual cost estimate in 2025.

Table ES-4. National Compliance Cost Estimates (millions of 2016$) for the Regulatory Control Alternatives

	Final Rule	More-Stringent Alternative	Less-Stringent Alternative
2021-2025 (Annualized)	10.0	41.4	-2.9
2021-2040 (Annualized)	24.8	28.5	19.6
2021 (Annual)	5.1	5.2	1.6
2025 (Annual)	1.6	4.0	-14.9
2030 (Annual)	63.6	32.3	67.0
2035 (Annual)	18.2	41.2	14.3
2040 (Annual)	8.8	134.0	18.9

The *2021-2025 (Annualized)* row reflects total estimated annual compliance costs levelized over the period 2021 through 2025, discounted using a 4.25 real discount rate.[15] The *2021-2040 (Annualized)* row reflects total estimated annual compliance costs levelized over the period 2021 through 2040, and discounted using a 4.25 real discount rate. This does not include compliance costs beyond 2040. The *2021 (Annual), 2025 (Annual), 2030 (Annual), 2035 (Annual), and 2040 (Annual)* rows reflect annual estimates in each of those years.

Under the Revised CSAPR Update, fully operating existing SCR controls provides a large share of the total emissions reductions. These options are selected in 2021, while upgrading to state-of-the-art combustion controls is assumed to begin in 2022.[16] Generation shifting costs are positive in 2021, but negative in 2025. The result is that the costs in 2021 are higher than costs in 2025. Projected costs for the illustrative Revised CSAPR Update peak in 2030 at $63.6 million (2016$) and annualized costs for the 2021-40 period are $24.8 million (2016$).

[15] This table reports compliance costs consistent with expected electricity sector economic conditions. An NPV of costs was calculated using a 4.25% real discount rate consistent with the rate used in IPM's objective function for cost-minimization. The NPV of costs was then used to calculate the levelized annual values over a 5-year period (2021-2025) and over a 20-year period (2021-2040) using the 4.25% rate as well. Tables ES-17 and 7-4 report the NPV of the annual stream of costs from 2021-2040 using 3% and 7% consistent with OMB guidance.

ES.6 Benefits

ES.6.1 Health Benefits Estimates

The Revised CSAPR Update is expected to reduce concentrations of ground-level ozone, $PM_{2.5}$, and CO_2 in the atmosphere (see Chapter 3 for discussion). Reducing NO_X emissions generally reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local levels of VOCs as discussed in Chapter 3. The rule would also reduce emissions of NO_X throughout the year. Because NO_X is also a precursor to formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects.[17] Reducing emissions of NO_X would also reduce ambient exposure to NO_2 and its associated health effects.

EPA historically has used evidence reported in the Integrated Science Assessment (ISA) for the most recent NAAQS review to inform its approach for quantifying air pollution-attributable health, welfare, and environmental impacts associated with that pollutant. The ISA synthesizes the toxicological, clinical and epidemiological evidence to determine whether each pollutant is causally related to an array of adverse human health outcomes associated with either short-term (hours to less than one month) or long-term (one month to years) exposure; for each outcome, the ISA reports this relationship to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship or not likely to be a causal. We estimate the incidence of air pollution-attributable premature deaths and illnesses using recently updated methods, reflecting the new evidence reported in the 2019 $PM_{2.5}$ and 2020 Ozone ISAs and accounting for recommendations from the Science Advisory Board. When updating each health endpoint EPA considered: (1) the extent to which there exists a causal relationship between that pollutant and the adverse effect; (2) whether suitable epidemiologic studies exist to support quantifying health impacts; (3) and whether robust economic approaches are available for estimating the value of the impact of reducing human exposure to the pollutant. Detailed descriptions of these updates are available in the TSD for the Final Revised Cross-State Air

[17] This RIA does not quantify $PM_{2.5}$-related benefits associated with SO_2 emission reductions. As discussed in Chapter 4, EPA does not estimate significant SO_2 emission reductions as a result of this action. Additionally, this RIA does not estimate changes in emissions of directly emitted particles.

Pollution Rule for the 2008 Ozone NAAQS Update titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*.

Table ES-5 and Table ES-6 report the estimated number of reduced premature deaths and illnesses in each year relative to the baseline along with the 95% confidence interval. The number of estimated reduced deaths and illnesses from the final rule and more and less stringent alternatives are calculated from the sum of individual reduced mortality and illness risk across the population. Table ES-7 and Table ES-8 report the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95% confidence interval. In each of these tables, for each discount rate and regulatory control alternative, multiple benefits estimates are presented reflecting alternative ozone and $PM_{2.5}$ mortality risk estimates.

Table ES-5. Estimated Avoided Ozone-Related Premature Respiratory Mortality and Illnesses for the Final and More and Less Stringent Alternatives for 2021 (95% Confidence Interval) [a,b]

		Final Rule	More Stringent Alternative	Less Stringent Alternative
Avoided premature respiratory mortality				
Long-term exposure	Turner *et al*. (2016)[c]	190 (130 to 250)	190 (130 to 250)	18 (13 to 24)
Short-term exposure	Katsouyanni *et al.* (2009)[cd] and Zanobetti *et al.* (2008)[d] pooled	9 (4 to 14)	9 (4 to 14)	1 (0 to 1)
	Katsouyanni *et al.* (2009)[cd]	9 (-5 to 21)	9 (-5 to 21)	1 (-0 to 2)
	Zanobetti *et al.* (2008)[e]	9 (4 to 13)	9 (4 to 13)	1 (0 to 1)
Morbidity effects				
Long-term exposure	Asthma onset[e]	1,300 (1,100 to 1,500)	1,300 (1,100 to 1,500)	130 (110 to 150)
	Allergic rhinitis symptoms[g]	7,700 (4,000 to 11,000)	7,700 (4,000 to 11,000)	750 (400 to 1,100)
Short-term exposure	Hospital admissions—respiratory[d]	21 (-5 to 46)	21 (-5 to 46)	2 (-1 to 5)
	ED visits—respiratory[f]	440 (120 to 920)	440 (120 to 920)	43 (12 to 90)
	Asthma symptoms	240,000 (-30,000 to 500,000)	240,000 (-30,000 to 500,000)	24,000 (-2,900 to 49,000)
	Minor restricted-activity days[d,f]	120,000 (49,000 to 200,000)	120,000 (49,000 to 200,000)	12,000 (4,800 to 19,000)
	School absence days	91,000 (-13,000 to 190,000)	91,000 (-13,000 to 190,000)	8,900 (-1,300 to 19,000)

[a] Values rounded to two significant figures.
[b] We estimated changes in annual mean $PM_{2.5}$ and $PM_{2.5}$ -related benefits in 2024, but not 2021. As discussed in Chapter 4, in 2021, the only control measure expected to be adopted for compliance in the regulatory control alternatives is optimization of existing SCRs, and this measure will operate only during the ozone season. As discussed in Chapter 3, NOx reductions in the ozone season provide minimal $PM_{2.5}$ benefits since $PM_{2.5}$ nitrate concentrations, which result from conversion of NOx emissions to nitrate, are minimal during the warmer temperatures during the ozone season. Conversely, the conversion of nitrates to $PM_{2.5}$ is much greater in cooler (non-ozone season) months, and thus it becomes worthwhile to estimate $PM_{2.5}$ benefits from NOx reductions in those months. In 2024, the presence of additional control measures that operate year-round and other changes in market conditions as a result of the rule lead to notable NOx reductions in the winter months.
[c] Applied risk estimate derived from April-September exposures to estimates of O_3 across the standard May-September warm season.
[d] Converted O_3 risk estimate metric from MDA1 to MDA8.
[e] Applied risk estimate derived from June-August exposures to estimates of O_3 across the standard May-September warm season.
[f] Applied risk estimate derived from full year exposures to estimates of O_3 across the standard May-September warm season.
[g] Converted O_3 risk estimate metric from DA24 to MDA8.

Table ES-6. Estimated Avoided $PM_{2.5}$ and Ozone-Related Mortality and Illnesses for the Final and More and Less Stringent Alternatives for 2024 (95% Confidence Interval) [a]

			Final	More Stringent Alternative	Less Stringent Alternative
Avoided premature mortality					
$PM_{2.5}$	Long-term exposure	Turner *et al*. (2016)[b]	4 (2 to 5)	4 (2 to 5)	--
		Di *et al*. (2017)	4 (3 to 4)	4 (3 to 4)	--
Ozone	Long-term exposure	Turner *et al*. (2016)	230 (160 to 300)	410 (280 to 530)	19 (13 to 25)
	Short-term exposure	Zanobetti *et al* (2008)[c] and Katsouyanni *et al* (2009)[b,d] pooled	10 (4 to 16)	18 (7 to 29)	1 (0 to 1)
		Katsouyanni *et al* (2009)[b,d]	10 (-6 to 26)	18 (-10 to 46)	1 (-0 to 2)
		Zanobetti *et al* (2008)[c]	10 (5 to 16)	18 (8 to 28)	1 (0 to 1)
$PM_{2.5}$- related non-fatal heart attacks among adults					
Short-term exposure		Peters et al. (2001)	4 (1 to 6)	4 (1 to 6)	--
		Pooled estimate	0 (0 to 1)	0 (0 to 1)	--
Morbidity effects					
Long-term exposure		Asthma onset[b,d] ($PM_{2.5}$ & O_3)	1,600 (1,400 to 1,800)	2,900 (2,500 to 3,300)	130 (110 to 150)
		Allergic rhinitis symptoms[e] ($PM_{2.5}$ & O_3)	9,200 (4,900 to 13,000)	17,000 (8,700 to 24,000)	770 (400 to 1,100)
		Stroke ($PM_{2.5}$)	0.2 (0 to 0.3)	0.2 (0 to 0.3)	--
		Lung cancer ($PM_{2.5}$)	0.4 (0.0 to 0.7)	0.4 (0.0 to 0.7)	--
		Hospital Admissions - Alzheimer's disease ($PM_{2.5}$)	2 (1 to 2)	2 (1 to 2)	--
		Hospital Admissions- Parkinson's disease ($PM_{2.5}$)	0.2 (0.1 to 0.3)	0.2 (0.1 to 0.3)	--
Short-term exposure		Hospital admissions- cardiovascular ($PM_{2.5}$)	0.5 (0.3 to 0.6)	0.5 (0.3 to 0.6)	--
		ED visits- cardiovascular ($PM_{2.5}$)	1 (-0 to 2)	1 (0 to 2)	--
		Hospital admissions—respiratory[h] ($PM_{2.5}$ & O_3)	27 (-7 to 60)	49 (-12 to 110)	2 (-1 to 5)
		ED visits —respiratory ($PM_{2.5}$ & O_3)	530 (150 to 1,100)	950 (260 to 2,000)	44 (12 to 92)
		Asthma symptoms[f] ($PM_{2.5}$ & O_3)	290,000 (-37,000 to 610,000)	530,000 (-66,000 to 1,100,000)	25,000 (-3,000 to 51,000)

Minor restricted-activity days ($PM_{2.5}$ & O_3)	150,000 (60,000 to 230,000)	260,000 (110,000 to 410,000)	12,000 (4,800 to 19,000)
Cardiac arrest ($PM_{2.5}$)	0.05 (-0.02 to 0.11)	0.05 (-0.02 to 0.11)	--
Lost work days ($PM_{2.5}$)	380 (320 to 440)	380 (320 to 440)	--
School absence days (O_3)	110,000 (-15,000 to 230,000)	200,000 (-28,000 to 410,000)	9,100 (-1,300 to 19,000)

[a] Values rounded to two significant figures.
[b] Applied risk estimate derived from April-September exposures to estimates of O_3 across the standard May-September warm season.
[c] Converted O_3 risk estimate metric from MDA1 to MDA8
[d] Applied risk estimate derived from June-August exposures to estimates of O_3 across the standard May-September warm season.
[e] Converted O_3 risk estimate metric from DA24 to MDA8
[f] Applied risk estimate derived from full year exposures to estimates of O_3 across the standard May-September warm season.

Table ES-7. Estimated Discounted Economic Value of Ozone-Attributable Premature Mortality and Illnesses for the Final Policy Scenarios in 2021 (95% Confidence Interval; millions of 2016$)[a,b]

	Final Rule			More Stringent Alternative			Less Stringent Alternative		
3% Discount Rate	$230 ($58 to $480)[c]	*and*	$1,900 ($210 to $5,000)[d]	$260 ($88 to $520)[c]	*and*	$1,900 ($210 to $5,000)[d]	$22 ($6 to $47)[c]	*and*	$190 ($20 to $490)[d]
7% Discount Rate	$200 ($38 to $460)[c]	*and*	$1,700 ($170 to $4,500)[d]	$200 ($38 to $460)[c]	*and*	$1,700 ($170 to $4,500)[d]	$20 ($4 to $45)[c]	*and*	$170 ($17 to $440)[d]

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated changes in annual mean $PM_{2.5}$ and $PM_{2.5}$ -related benefits in 2024, but not 2021. As discussed in Chapter 4, in 2021, the only control measure expected to be adopted for compliance in the regulatory control alternatives is optimization of existing SCRs, and this measure will operate only during the ozone season. As discussed in Chapter 3, NOx reductions in the ozone season provide minimal $PM_{2.5}$ benefits since $PM_{2.5}$ nitrate concentrations, which result from conversion of NOx emissions to nitrate, are minimal during the warmer temperatures during the ozone season. Conversely, the conversion of nitrates to $PM_{2.5}$ is much greater in cooler (non-ozone season) months, and thus it becomes worthwhile to estimate $PM_{2.5}$ benefits from NOx reductions in those months. In 2024, the presence of additional control measures that operate year-round and other changes in market conditions as a result of the rule lead to notable NOx reductions in the winter months.
[c] Sum of ozone mortality estimated using the pooled Katsouyanni et al. (2009) and Zanobetti and Schwartz (2008) short-term risk estimate and the Di et al. (2017) long-term mortality risk estimate. As PM-related mortality quantified using risk estimates from the Di et al. (2017) and Turner et al. (2016) are within 5% of one another, in the interest of clarity and simplicity, we present the results estimated using the risk estimate from Di et al. (2017) alone.
[d] Sum of ozone mortality estimated using the long-term risk estimate and the Di et al. (2017) long-term mortality risk estimate. As PM-related mortality quantified using risk estimates from the Di et al. (2017) and Turner et al. (2016) are within 5% of one another, in the interest of clarity and simplicity, we present the results estimated using the risk estimate from Di et al. (2017) alone.

Table ES-8. Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illnesses for the Final Policy Scenario in 2024 (95% Confidence Interval; millions of 2016$)[a]

	Final Rule			More Stringent Alternative			Less Stringent Alternative[b]		
3% Discount Rate	$310 ($72 to $680)[c]	*and*	$2,400 ($250 to $6,200)[d]	$530 ($130 to $1,100)[c]	*and*	$4,200 ($450 to $11,000)[d]	$22 ($6 to $47)[c]	*and*	$190 ($20 to $490)[d]
7% Discount Rate	$280 ($48 to $640)[c]	*and*	$2,100 ($210 to $5,600)[d]	$470 ($84 to $1,100)[c]	*and*	$3,800 ($370 to $9,900)[d]	$20 ($4 to $45)[c]	*and*	$170 ($17 to $440)[d]

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] No PM-attributable benefits accrue for this scenario.
[c] Sum of ozone mortality estimated using the pooled Katsouyanni et al. (2009) and Zanobetti and Schwartz (2008) short-term risk estimate and the Di et al. (2017) long-term mortality risk estimate. As PM-related mortality quantified using risk estimates from the Di et al. (2017) and Turner et al. (2016) are within 5% of one another, in the interest of clarity and simplicity, we present the results estimated using the risk estimate from Di et al. (2017) alone.
[d] Sum of ozone mortality estimated using the long-term risk estimate and the Di et al. (2017) long-term mortality risk estimate. As PM-related mortality quantified using risk estimates from the Di et al. (2017) and Turner et al. (2016) are within 5% of one another, in the interest of clarity and simplicity, we present the results estimated using the risk estimate from Di et al. (2017) alone.

ES.6.2 Climate Benefits Estimates

We estimate the climate benefits for this final rulemaking using a measure of the social cost of carbon (SC-CO_2). The SC-CO_2 is the monetary value of the net harm to society associated with a marginal increase in CO_2 emissions in a given year, or the benefit of avoiding that increase. In principle, SC-CO_2 includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-CO_2, therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton. The SC-CO_2 is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2 emissions.

We estimate the global social benefits of CO_2 emission reductions expected from this final rule using the SC-CO_2 estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* (IWG 2021). These SC-CO_2 estimates are interim values developed under Executive Order (E.O.) 13990 for use in benefit-cost analyses until an improved estimate of the impacts of climate change can be developed based on the best available science and economics. These SC-CO_2 estimates are the same as those used in the 2016 Final CSAPR Update RIA.

The SC-CO_2 estimates used in this analysis were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. The SC-CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC-CO_2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-CO_2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*, and recommended specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies 2017). On January 20, 2021, President Biden issued Executive Order 13990, which directed the IWG to ensure that the U.S. Government's (USG) estimates of the social cost of carbon and other greenhouse gases reflect the best available science and the recommendations of the National Academies (2017). The IWG was tasked with first reviewing the estimates currently used by the USG and publishing interim estimates within 30 days of E.O. 13990 that reflect the full impact of GHG emissions, including taking global damages into account.[18] The interim SC-CO_2 estimates published in February 2021 are used here to estimate the climate benefits for this final rulemaking.[19]

[18] The E.O. instructs the IWG to undertake a fuller update of the SC-GHG estimates by January 2022.
[19] The values used in the proposal RIA were interim values developed under E.O. 13783 (signed March 28, 2017) for use in regulatory analyses. E.O. 13783 withdrew the TSDs used in the benefits analysis of the 2016 CSAPR Update (U.S. EPA, 2016b) for describing the global social cost of greenhouse gas estimates as no longer representative of government policy. Thus, EPA followed E.O. 13783 by using SC-CO_2 estimates reflecting impacts occurring within U.S. borders and 3% and 7% discount rates in our central analysis for the proposal RIA.

Table ES-9 summarizes the interim global SC-CO_2 estimates for the years 2015 to 2050. These estimates are reported in 2016 dollars but are otherwise identical to those presented in the IWG's 2016 TSD (IWG 2016a). For purposes of capturing uncertainty around the SC-CO_2 estimates in analyses, we emphasize the importance of considering all four of the SC-CO_2 values. The SC-CO_2 increases over time within the models – i.e., the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2025 – because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

Table ES-9. Interim Global Social Cost of Carbon Values (2016$/Metric Tonne CO_2)

Emissions Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2020	$13	$47	$71	$140
2025	$15	$52	$77	$160
2030	$18	$57	$83	$170
2035	$20	$63	$90	$190
2040	$23	$67	$95	$210
2045	$26	$73	$100	$220
2050	$29	$78	$110	$240

Note: These SC-CO_2 values are identical to those used in the 2016 Final CSPAR Update RIA adjusted for inflation to 2016 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) NIPA Table 1.1.9 (U.S. BEA 2021). The values are stated in $/metric tonne CO_2 (1 metric tonne equals 1.102 short tons) and vary depending on the year of CO_2 emissions. This table displays the values rounded to the nearest dollar; the annual unrounded values used in the calculations in this RIA are available on OMB's website: <https://www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/>. Source: Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (February 2021).

Table ES-10 shows the estimated monetary value of the estimated changes in CO_2 emissions expected to occur over 2021 - 2040 for the Revised CSAPR Update, the more-stringent alternative, and the less-stringent alternative. EPA estimated the dollar value of the CO_2-related effects for each analysis year between 2021 and 2040 by applying the SC-CO_2 estimates, shown in Table ES-9, to the estimated changes in CO_2 emissions in the corresponding year under the regulatory options.

Table ES-10. Estimated Total Annual Global Climate Benefits (2021-40) from Changes in CO_2 Emissions (Millions of 2016$)

Regulatory Alternative	Year	5% Discount Rate	3% Discount Rate	2.5% Discount Rate	3% Discount Rate (95th Percentile)
Final	2021	0	1	1	2

	2022	46	143	206	434
	2023	94	290	417	882
	2024	102	311	444	946
	2025	109	331	473	1,011
	2030	128	373	525	1,146
	2035	98	273	380	838
	2040	127	340	467	1,043
More-Stringent Alternative	2021	1	2	3	7
	2022	76	237	341	720
	2023	156	480	689	1,460
	2024	204	623	892	1,898
	2025	254	771	1,100	2,350
	2030	323	939	1,322	2,885
	2035	316	878	1,222	2,698
	2040	383	1,025	1,410	3,146
Less-Stringent Alternative	2021	0	1	1	3
	2022	39	122	176	371
	2023	80	248	356	754
	2024	81	248	355	755
	2025	82	248	353	755
	2030	93	271	381	831
	2035	73	203	282	623
	2040	91	242	333	743

Note: We emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates. As discussed in Chapter 5 and in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

ES.6.3 Total Benefits

Table ES-11 through Table ES-13 present the total health and climate benefits for the final rule and the more and less stringent alternatives.

Table ES-11. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2021 (millions of 2016$)[a]

SC-CO_2 Discount Rate and Statistic	**Health and Climate Benefits (Discount Rate Applied to Health Benefits)**		**Climate Benefits Only[b]**
	3%	**7%**	
Final Rule			
5% (average)	$230 and $1,900	$200 and $1,700	$0
3% (average)	$230 and $1,900	$200 and $1,700	$1
2.5% (average)	$230 and $1,900	$200 and $1,700	$1
3% (95th percentile)	$230 and $1,900	$200 and $1,700	$2
More Stringent Alternative			
5% (average)	$260 and $1,900	$200 and $1,700	$1
3% (average)	$260 and $1,900	$200 and $1,700	$2
2.5% (average)	$260 and $1,900	$200 and $1,700	$3

SC-CO_2 Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only[b]
	3%	7%	
3% (95th percentile)	$270 and $1,900	$210 and $1,700	$7
Less Stringent Alternative			
5% (average)	$20 and $190	$20 and $170	$0
3% (average)	$20 and $190	$20 and $170	$1
2.5% (average)	$20 and $190	$20 and $170	$1
3% (95th percentile)	$20 and $190	$20 and $170	$3

[a] The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates; the additional benefit estimates range from $0.24 million to $2.31 million in 2021 for the finalized option. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

Table ES-12. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2025 (millions of 2016$)[a]

SC-CO_2 Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only[b]
	3%	7%	
Final Rule			
5% (average)	$430 and $2,500	$400 and $2,300	$110
3% (average)	$650 and $2,700	$620 and $2,500	$330
2.5% (average)	$790 and $2,900	$760 and $2,700	$470
3% (95th percentile)	$1,300 and $3,400	$1,300 and $3,200	$1,000
More Stringent Alternative			
5% (average)	$790 and $4,500	$740 and $4,000	$250
3% (average)	$1,300 and $5,000	$1,300 and $4,600	$770
2.5% (average)	$1,600 and $5,300	$1,600 and $4,900	$1,100
3% (95th percentile)	$2,900 and $6,600	$2,900 and $6,200	$2,400
Less Stringent Alternative			
5% (average)	$100 and $280	$100 and $250	$80
3% (average)	$270 and $450	$270 and $420	$250
2.5% (average)	$370 and $550	$370 and $520	$350
3% (95th percentile)	$780 and $960	$780 and $930	$760

[a] The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount

rates; 95th percentile at 3 percent discount rate). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four $SC\text{-}CO_2$ estimates; the additional benefit estimates range from $109 million to $1,011 million in 2025 for the finalized option. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

Table ES-13. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2030 (millions of 2016$)[a]

$SC\text{-}CO_2$ Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only[b]
	3%	7%	
Final Rule			
5% (average)	$470 and $2,700	$460 and $2,600	$130
3% (average)	$710 and $3,000	$700 and $2,900	$370
2.5% (average)	$870 and $3,100	$860 and $3,000	$530
3% (95th percentile)	$1,400 and $3,700	$1,430 and $3,600	$1,100
More Stringent Alternative			
5% (average)	$910 and $4,900	$880 and $4,200	$320
3% (average)	$1,500 and $5,500	$1,500 and $4,800	$940
2.5% (average)	$1,900 and $5,900	$1,900 and $5,200	$1,300
3% (95th percentile)	$3,500 and $7,500	$3,500 and $6,800	$2,900
Less Stringent Alternative			
5% (average)	$120 and $300	$110 and $270	$90
3% (average)	$300 and $480	$290 and $450	$270
2.5% (average)	$410 and $590	$400 and $560	$380
3% (95th percentile)	$860 and $1,040	$850 and $1,010	$830

[a] The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon ($SC\text{-}CO_2$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four $SC\text{-}CO_2$ estimates; the additional benefit estimates range from $128 million to $1,146 million in 2030 for the finalized option. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

ES.6.4 Unquantified Health and Welfare Benefits Categories

Data, time, and resource limitations prevented EPA from quantifying the estimated impacts or monetizing estimated benefits associated with exposure to NO_2 (independent of the role NO_2 plays as precursors to $PM_{2.5}$), as well as ecosystem effects, and visibility impairment due to the absence of air quality modeling data for these pollutants in this analysis. Lack of quantification does not imply that there are no benefits associated with reductions in exposures to ozone, $PM_{2.5}$, or NO_2. For a qualitative description of these benefits, please see Chapter 5, section 5.4, Table 5-13.

ES.7 Results of Benefit-Cost Analysis

Below in Table ES-14 through Table ES-16, we present the annual costs and benefits estimates for 2021, 2025, and 2030, respectively. We present the costs and benefits for the years 2021 through 2040 at real discount rates of 3 and 7 percent in Table ES-17. This analysis uses annual compliance costs reported above as a proxy for social costs. The net benefits of the rule and more and less stringent alternatives reflect the benefits of implementing EGU emissions reductions strategies for the affected 12 states via the FIPs minus the costs of those emissions reductions. The estimated social costs to implement the rule, as described in this document, are approximately \$5 million in 2021 and \$2 million in 2025 (2016\$).

The estimated monetized health benefits from implementation of the rule are approximately \$230 and \$1,900 million in 2021 (2016\$, based on a real discount rate of 3 percent) with the two values reflecting alternative ozone and $PM_{2.5}$ mortality risk estimates. For 2025, the estimated monetized health benefits from implementation of the rule are approximately \$320 and \$2,400 million (2016\$, based on a real discount rate of 3 percent). The estimated monetized climate benefits are \$1 million in 2021 (using a 3 percent real discount rate) and \$330 million in 2025.

EPA calculates the net benefits of the rule by subtracting the estimated compliance costs from the estimated benefits in 2021, 2025, and 2030. The benefits include those to public health and climate. The two estimates of the benefits and net-benefits for each discount rate reflect alternative ozone and $PM_{2.5}$ mortality risk estimates. The annual net benefits of the rule in 2021 (in 2016\$) are approximately \$230 and \$1,900 million using a 3 percent discount rate. The annual net benefits of the rule in 2025 are approximately \$650 and \$2,700 using a 3 percent real discount rate. The annual net benefits of the rule in 2030 are approximately \$650 and \$2,900 million using a 3 percent real discount rate. Table ES-14 presents a summary of the benefits, costs, and net benefits of the rule and the more and less stringent alternatives for 2021. Table ES-15 presents a summary of these impacts for the rule and the more and less stringent alternatives for 2025, and Table ES-16 presents a summary of these impacts for the rule and the more and less stringent alternatives for 2030.

Table ES-14. Benefits, Costs, and Net Benefits of the Final Rule and More and Less Stringent Alternatives for 2021 for the U.S. (millions of 2016$)[a,b,c]

	Final Rule	More Stringent Alternative	Less Stringent Alternative
Health Benefits (3%)	$230 and $1,900	$260 and $1,900	$20 and $190
Climate Benefits (3%)	$1	$2	$1
Total Benefits	$230 and $1,900	$260 and $1,900	$20 and $190
Costs	$5	$5	$2
Net Benefits	**$230 and $1,900**	**$260 and $1,900**	**$20 and $190**
Health Benefits (7%)	$200 and $1,700	$200 and $1,700	$20 and $170
Climate Benefits (3%)	$1	$2	$1
Total Benefits	$200 and $1,700	$200 and $1,700	$20 and $170
Costs	$5	$5	$2
Net Benefits	**$200 and $1,700**	**$200 and $1,700**	**$20 and $170**

[a] We focus results to provide a snapshot of costs and benefits in 2021, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Benefits include those related to public health and climate. The health benefits are associated with several point estimates and are presented at real discount rates of 3 percent and 7 percent. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CO_2 at a 3 percent discount rate, but the Agency does not have a single central SC-CO_2 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates; the additional benefit estimates range from $0.24 million to $2.31 million in 2021 for the finalized option. Please see Table 5-9 for the full range of SC-CO_2 estimates. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. The costs presented in this table are 2021 annual estimates for each alternative analyzed.
[c] Rows may not appear to add correctly due to rounding.

Table ES-15. Benefits, Costs, and Net Benefits of the Final Rule and More and Less Stringent Alternatives for 2025 for the U.S. (millions of 2016$)[a,b,c]

	Final Rule	More Stringent Alternative	Less Stringent Alternative
Health Benefits (3%)	$320 and $2,400	$540 and $4,200	$20 and $200
Climate Benefits (3%)	$330	$770	$250
Total Benefits	$650 and $2,700	$1,300 and $5,000	$270 and $450
Costs	$2	$4	-$15
Net Benefits	**$650 and $2,700**	**$1,300 and $5,000**	**$280 and $460**
Health Benefits (7%)	$290 and $2,200	$490 and $3,800	$20 and $170
Climate Benefits (3%)	$330	$770	$250
Total Benefits	$620 and $2,500	$1,300 and $4,600	$270 and $420

Costs	$2	$4	-$15
Net Benefits	**$620 and $2,500**	**$1,300 and $4,500**	**$280 and $430**

[a] We focus results to provide a snapshot of costs and benefits in 2025, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Benefits include those related to public health and climate. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CO_2 at a 3 percent discount rate, but the Agency does not have a single central SC-CO_2 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates; the additional benefit estimates range from $109 million to $1,011 million in 2025 for the finalized option. Please see Table 5-9 for the full range of SC-CO_2 estimates. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. The costs presented in this table are 2025 annual estimates for each alternative analyzed.

Table ES-16. Benefits, Costs, and Net Benefits of the Final Rule and More and Less Stringent Alternatives for 2030 for the U.S. (millions of 2016$)[a,b,c]

	Final Rule	**More Stringent Alternative**	**Less Stringent Alternative**
Health Benefits (3%)	$340 and $2,600	$590 and $4,600	$30 and $210
Climate Benefits (3%)	$370	$940	$270
Total Benefits	$710 and $3,000	$1,500 and $5,500	$300 and $480
Costs	$64	$32	$67
Net Benefits	**$650 and $2,900**	**$1,500 and $5,500**	**$230 and $410**
Health Benefits (7%)	$330 and $2,500	$560 and $3,900	$20 and $180
Climate Benefits (3%)	$370	$940	$270
Total Benefits	$700 and $2,900	$1500 and $4,800	$290 and $450
Costs	$64	$32	$67
Net Benefits	**$640 and $2,800**	**$1,500 and $4,800**	**$220 and $380**

[a] We focus results to provide a snapshot of costs and benefits in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Benefits include those related to public health and climate. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CO_2 at a 3 percent discount rate, but the Agency does not have a single central SC-CO_2 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates; the additional benefit estimates range from $128 million to $1,146 million in 2030 for the finalized option Please see Table 5-9 for the full range of SC-CO_2 estimates. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. The costs presented in this table are 2030 annual estimates for each alternative analyzed.
[c] Rows may not appear to add correctly due to rounding.

As part of fulfilling analytical guidance with respect to E.O. 12866, EPA presents estimates of the present value (PV) of the benefits and costs over the twenty-year period 2021 to 2040. To calculate the present value of the social net-benefits of the Revised CSAPR Update, annual benefits and costs are discounted to 2021 at 3 percent and 7 discount rates as directed by OMB's Circular A-4. The EPA also presents the equivalent annualized value (EAV), which represents a flow of constant annual values that, had they occurred in each year from 2021 to 2040, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates mentioned earlier in the RIA.

For the twenty-year period of 2021 to 2040, the PV of the net benefits, in 2016$ and discounted to 2021, is $8,800 and $41,000 million when using a 3 percent discount rate and $7,300 and $29,000 million when using a 7 percent discount rate. The EAV is $590 and $2,800 million per year when using a 3 percent discount rate and $570 and $2,700 million when using a 7 percent discount rate. The comparison of benefits and costs in PV and EAV terms for the rule can be found in Table ES-17. Estimates in the table are presented as rounded values and are based on air quality simulations run for years 2021 and 2024.

Table ES-17. Summary of Annual Values, Present Values and Equivalent Annualized Values for the 2021-2040 Timeframe for Estimated Compliance Costs, Benefits, and Net Benefits for the Final Rule (millions of 2016$, discounted to 2021)[a,b,c]

	Health Benefits		Climate Benefits[c]	Cost[d]		Net Benefits	
	3%	7%	3%	3%	7%	3%	7%
2021*	$230 and $1,900	$200 and $1,700	$1	$5		$230 and $1,900	$200 and $1,700
2022	$230 and $2,000	$210 and $1,600	$140	$19		$350 and $2,100	$330 and $1,700
2023	$230 and $2,000	$210 and $1,600	$290	$19		$500 and $2,300	$480 and $1,900
2024*	$310 and $2,400	$280 and $2,100	$310	$2		$620 and $2,700	$590 and $2,400
2025	$320 and $2,400	$290 and $2,200	$330	$2		$650 and $2,700	$620 and $2,500
2026	$330 and $2,500	$290 and $2,200	$340	$1		$670 and $2,800	$630 and $2,500
2027	$320 and $2,400	$300 and $2,300	$350	$0		$670 and $2,800	$650 and $2,700
2028	$330 and $2,500	$310 and $2,400	$360	$66		$620 and $2,800	$600 and $2,700
2029	$330 and $2,500	$320 and $2,400	$360	$65		$630 and $2,800	$620 and $2,700
2030	$340 and $2,600	$330 and $2,500	$370	$64		$650 and $2,900	$640 and $2,800
2031	$350 and $2,600	$340 and $2,600	$350	$64		$640 and $2,900	$630 and $2,900
2032	$360 and $2,700	$350 and $2,600	$330	$63		$630 and $3,000	$620 and $2,900
2033	$350 and $2,600	$360 and $2,700	$310	$18		$640 and $2,900	$650 and $3,000
2034	$360 and $2,700	$370 and $2,800	$290	$18		$630 and $3,000	$640 and $3,100
2035	$370 and $2,800	$380 and $2,800	$270	$18		$620 and $3,100	$630 and $3,100
2036	$370 and $2,800	$390 and $2,900	$290	$18		$640 and $3,100	$660 and $3,200
2037	$380 and $2,900	$400 and $3,000	$300	$18		$660 and $3,200	$680 and $3,300
2038	$370 and $2,800	$410 and $3,100	$310	$9		$670 and $3,100	$710 and $3,400
2039	$380 and $2,800	$430 and $3,200	$330	$9		$700 and $3,100	$750 and $3,500
2040	$380 and $2,900	$440 and $3,200	$340	$9		$710 and $3,200	$770 and $3,500
PV 2021-2040	**$4,800 and $37,000**	**$3,200 and $25,000**	**$4,400**	**$370**	**$260**	**$8,800 and $41,000**	**$7,300 and $29,000**
EAV 2021 - 2040	**$320 and $2,500**	**$300 and $2,400**	**$290**	**$25**	**$25**	**$590 and $2,800**	**$570 and $2,700**

[a] Rows may not appear to add correctly due to rounding. The two benefits estimates are separated by the word “and” to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] The annualized present value of costs and benefits are calculated over a 20-year period from 2021 to 2040.
[c] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.
[d] The costs presented in this table are consistent with the costs presented in Chapter 4, Table 4-6. To estimate these annualized costs, EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. Annual costs were calculated using a 4.25% real discount rate consistent with the rate used in IPM’s objective function for cost-minimization.
*Year in which air quality was simulated. Ozone air quality was simulated in 2021 and 2024 while the formation of $PM_{2.5}$ was simulated only in 2024. Health benefits for all other years were linearly extrapolated or interpolated from model-simulated air quality in these years. This method assumes that ozone and $PM_{2.5}$ formation reaches a steady state beyond 2024 and may create increasing uncertainty in the benefits estimates the farther into the future estimates are extrapolated. Benefits calculated as value of avoided: $PM_{2.5}$-attributable deaths (quantified using a concentration-response relationship from the Di et al. 2017 study); Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2017 study); and $PM_{2.5}$ and ozone-related morbidity effects.

CHAPTER 1: INTRODUCTION AND BACKGROUND

Overview

EPA originally published the Cross-State Air Pollution Rule (CSAPR) on August 8, 2011, to address interstate transport of ozone pollution under the 1997 ozone National Ambient Air Quality Standards (NAAQS).[1] On October 26, 2016, EPA published the CSAPR Update, which finalized Federal Implementation Plans (FIPs) for 22 states that EPA found failed to submit a complete good neighbor State Implementation Plan (SIP) (15 states)[2] or for which EPA issued a final rule disapproving their good neighbor SIP (7 states).[3] The FIPs promulgated for these states included new electric generating unit (EGU) oxides of nitrogen (NO_X) ozone season emission budgets to reduce interstate transport for the 2008 ozone NAAQS.[4] These emission budgets took effect in 2017 in order to assist downwind states with attainment of the 2008 ozone NAAQS by the 2018 Moderate area attainment date. EPA acknowledged at the time that the FIPs promulgated for 21 of the 22 states only partially addressed good neighbor obligations under the 2008 ozone NAAQS.[5]

This final action is taken in response to the United States Court of Appeals for the District of Columbia Circuit's (D.C. Circuit) September 13, 2019 remand of the CSAPR Update.[6] The D.C. Circuit found that the CSAPR Update, which was a partial remedy, was unlawful to the extent it allowed those states to continue their significant contributions to downwind ozone problems beyond the statutory dates by which downwind states must demonstrate their attainment of the air quality standards. This final rule will resolve 21 states' outstanding interstate ozone transport obligations with respect to the 2008 ozone NAAQS.

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[1] CSAPR also addressed interstate transport of fine particulate matter ($PM_{2.5}$) under the 1997 and 2006 $PM_{2.5}$ NAAQS.

[2] Alabama, Arkansas, Illinois, Iowa, Kansas, Maryland, Michigan, Mississippi, Missouri, New Jersey, Oklahoma, Pennsylvania, Tennessee, Virginia, and West Virginia.

[3] Indiana, Kentucky, Louisiana, New York, Ohio, Texas, and Wisconsin.

[4] The 2008 ozone NAAQS is an 8-hour standard that was set at 75 parts per billion (ppb). See 73 FR 16436 (March 27, 2008).

[5] In the CSAPR Update, EPA found that the finalized Tennessee emission budget fully addressed Tennessee's good neighbor obligation with respect to the 2008 ozone NAAQS. As such, Tennessee is not considered in this rule, and the number of states included is reduced from 22 to 21 states.

[6] EPA is taking this action to address the remand of the CSAPR Update in *Wisconsin v. EPA*, 938 F.3d 303 (D.C. Cir. 2019). The court remanded but did not vacate the CSAPR Update, finding that vacatur of the rule could cause harm to public health and the environment or disrupt the trading program EPA had established and that the obligations imposed by the rule may be appropriate and sustained on remand.

This action, the Revised CSAPR Update rule, finds that for 9 of the 21 states with remanded FIPs (Alabama, Arkansas, Iowa, Kansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin), their projected 2021 ozone season nitrogen oxides (NOx) emissions do not significantly contribute to a continuing downwind nonattainment and/or maintenance problem; therefore the CSAPR Update fully addresses their interstate ozone transport obligations with respect to the 2008 ozone NAAQS. This action also finds that for the 12 remaining states (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia), their projected 2021 ozone season NOx emissions significantly contribute to downwind states' nonattainment and/or maintenance problems for the 2008 ozone NAAQS. For these 12 states, EPA amends their FIPs to revise the existing CSAPR NOx Ozone Season Group 2 emissions budgets for EGUs and implement the revised budgets via a new CSAPR NOx Ozone Season Group 3 Trading Program.[7] EPA is implementing the revised emission budgets starting with the 2021 ozone season (May 1 – September 30), as outlined in section VII of the preamble.

These emission budgets represent the remaining EGU emissions after reducing those amounts of each state's emissions that significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states, as required under Clean Air Act (CAA) section 110(a)(2)(D)(i)(I). The allowance trading program is the remedy in the FIPs that achieves the ozone season NO_X emission reductions in the rule. The allowance trading program essentially converts the EGU NO_X emission budget for each of the 12 states into a limited number of NO_X allowances that, on a tonnage basis, equal the state's ozone season NO_X emission budget. EGUs covered by the FIPs can trade NO_X ozone season allowances among EGUs within their state and across state boundaries, subject to certain limits. The EGUs covered by the FIPs and subject to the budget are fossil-fired EGUs with >25MW capacity. The 12 Group 3 states may not use allowances allocated under the CSAPR Update for compliance in 2021 and later.[8] Also, allowances allocated under the Revised CSAPR Update may not be used for

[7] The CSAPR Update established a second NO_X ozone season trading program for the 22 states determined to have good neighbor obligations with respect to the 2008 ozone NAAQS – the CSAPR NO_X Ozone Season Group 2 trading program.

[8] EGUs can still use converted banked allowances from the CSAPR Update to comply with this rule.

compliance in the 10 Group 2 states that remain subject to the budgets established in the CSAPR Update.

Consistent with OMB Circular A-4 and EPA's *Guidelines for Preparing Economic Analyses* (2010), this Regulatory Impact Analysis (RIA) presents the benefits and costs of the rule from 2021 through 2040. The estimated benefits are those health and climate benefits expected to arise from reduced air pollution and the estimated costs are the increased costs of producing electricity and any state reporting requirements as a result of this rule. Unquantified benefits and costs are described qualitatively. The RIA also provides (i) estimates of other impacts of the rule including its effect on retail electricity prices and fuel production and (ii) an assessment of how expected compliance with the rule will affect concentrations at nonattainment and maintenance receptors. This chapter contains background information relevant to the rule and an outline of the chapters of this RIA.

1.1 Background

Clean Air Act (CAA or the Act) section 110(a)(2)(D)(i)(I), which is also known as the "good neighbor provision," requires states to prohibit emissions that will contribute significantly to nonattainment or interfere with maintenance in any other state with respect to any primary or secondary NAAQS. The statute vests states with the primary responsibility to address interstate emission transport through the development of good neighbor State Implementation Plans (SIPs), which are one component of larger SIP submittals typically required three years after EPA promulgates a new or revised NAAQS. These larger SIPs are often referred to as "infrastructure" SIPs or iSIPs. *See* CAA section 110(a)(1) and (2). EPA supports state efforts to submit good neighbor SIPs for the 2008 ozone NAAQS and has shared information with states to facilitate such SIP submittals. However, the CAA also requires EPA to fill a backstop role by issuing FIPs where states fail to submit good neighbor SIPs or EPA disapproves a submitted good neighbor SIP.

As described in the preamble for the rule, to reduce interstate emission transport under the authority provided in CAA section 110(a)(2)(D)(i)(I), this rule further limits ozone season (May 1 through September 30) NOx emissions from EGUs in 12 states using the same framework used by EPA in developing the original CSAPR (the Interstate Transport

Framework). The Interstate Transport Framework provides a 4-step process to address the requirements of the good neighbor provision for ground-level ozone and fine particulate matter ($PM_{2.5}$) NAAQS: (1) identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (2) determining which upwind states contribute to these identified problems in amounts sufficient to "link" them to the downwind air quality problems (*i.e.*, here, a 1 percent contribution threshold); (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind, implementing the necessary emissions reductions through enforceable measures. Details on the methods and results of applying this process can be found in the preamble for this rule.

1.1.1 Role of Executive Orders in the Regulatory Impact Analysis

Several statutes and executive orders apply to federal rulemakings. The analyses required by these statutes, along with a brief discussion of several executive orders, are presented in Chapter 6. Below we briefly discuss the requirements of Executive Orders 12866 and 13563 and the guidelines of the Office of Management and Budget (OMB) Circular A-4 (U.S. OMB, 2003).

In accordance with Executive Orders 12866 and 13563 and the guidelines of OMB Circular A-4, the RIA analyzes the benefits and costs associated with emissions reductions for compliance with the Revised CSAPR Update rule. OMB Circular A-4 requires analysis of one potential regulatory control alternative more stringent than the rule and one less stringent than the rule. This RIA evaluates the benefits, costs, and certain impacts of a more and a less stringent alternative to the selected alternative in this rule.

1.1.2 Alternatives Analyzed

EPA is amending FIPs for 12 states to revise the existing CSAPR NOx Ozone Season Group 2 emissions budgets for EGUs and implement the revised budgets via a new CSAPR NOx Ozone Season Group 3 Trading Program. Note that EGUs have flexibility in determining how they will comply with the allowance trading program. EPA is implementing the revised emission budgets starting with the 2021 ozone season.

In response to OMB Circular A-4, this RIA analyzes the Revised CSAPR Update emission budgets as well as a more and a less stringent alternative to the rule. The more and less stringent alternatives differ from the Revised CSAPR Update in that they set different EGU NO_X ozone season emission budgets for the affected EGUs. The less-stringent scenario uses emission budgets that were developed using a uniform control stringency represented by $500 per ton (2016$). The more-stringent scenario uses emission budgets that were developed using a uniform control stringency represented by $9,600 per ton (2016$). See Chapter 4, section 4.1 below, section VII of the preamble, and the EGU NO_X Mitigation Strategies Final Rule TSD, in the docket for this rule[9] for further details of these emission budgets.

1.1.3 The Need for Air Quality or Emissions Regulation

OMB Circular A-4 indicates that one of the reasons a regulation may be issued is to address a market failure. The major types of market failure include externalities, market power, and inadequate or asymmetric information. Correcting market failures is one reason for regulation; it is not the only reason. Other possible justifications include improving the function of government, correcting distributional unfairness, or securing privacy or personal freedom.

Environmental problems are classic examples of externalities – uncompensated benefits or costs imposed on another party as a result of one's actions. For example, the smoke from a factory may adversely affect the health of local residents and soil the property in nearby neighborhoods. Pollution emitted in one state may be transported across state lines and affect air quality in a neighboring state. If bargaining were costless and all property rights were well defined, people would eliminate externalities through bargaining without the need for government regulation.

From an economics perspective, achieving emissions reductions (i.e., by establishing the EGU NO_X ozone-season emissions budgets in this rule) through a market-based mechanism is a straightforward and cost-effective remedy to address an externality in which firms emit pollutants, resulting in health and environmental problems without compensation for those incurring the problems. Capping emissions through allowance allocations incentivizes those who

[9] Docket ID No. EPA-HQ-OAR-2020-0272

emit the pollutants to reduce their emissions, which lessens the impact on those who suffer the health and environmental problems from higher levels of pollution.

1.2 Overview and Design of the RIA

1.2.1 Methodology for Identifying Needed Reductions

In order to apply the first and second steps of the CSAPR 4-step Interstate Transport Framework to interstate transport for the 2008 ozone NAAQS, EPA first performed air quality modeling coupled with ambient measurements in an interpolation technique to project ozone concentrations at air quality monitoring sites in 2021. EPA evaluated 2021 projected ozone concentrations at individual monitoring sites and considered current ozone monitoring data at these sites to identify receptors that are anticipated to have problems attaining or maintaining the 2008 ozone NAAQS. In this analysis, downwind air quality problems are defined by receptors that are projected to be unable to attain (i.e., nonattainment receptor) or maintain (i.e., maintenance receptor) the 2008 ozone NAAQS.

To apply the second step of the Interstate Transport Framework, EPA used air quality modeling to quantify the contributions from upwind states to ozone concentrations in 2021 at downwind receptors. Once quantified, EPA then evaluated these contributions relative to a screening threshold of 1 percent of the NAAQS. States with contributions that equal or exceed 1 percent of the NAAQS are identified as warranting further analysis for significant contribution to nonattainment or interference with maintenance.[10] States with contributions below 1 percent of the NAAQS are considered to not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states.

To apply the third step of the Interstate Transport Framework, EPA applied a multi-factor test to evaluate cost, available emission reductions, and downwind air quality impacts to determine the appropriate level of uniform NOx control stringency that addresses the impacts of interstate transport on downwind nonattainment or maintenance receptors. EPA used this multi-

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[10] EPA assessed the magnitude of the maximum projected design value for 2021 at each receptor in relation to the 2008 ozone NAAQS. Where the value exceeds the NAAQS, EPA determined that receptor to be a maintenance receptor for purposes of defining interference with maintenance. That is, monitoring sites with a maximum design value that exceeds the NAAQS are projected to have a maintenance problem in 2021.

factor assessment to gauge the extent to which emission reductions are needed, and to ensure any required reductions do not result in over-control.

Using the multi-factor test, EPA identified a control strategy for EGUs at a stringency level that maximizes cost-effective emission reductions.[11] This control strategy reflects the optimization of existing selective catalytic reduction (SCR) controls, optimization of existing selective non-catalytic reduction (SNCR) controls, and installation of state-of-the-art NOx combustion controls, at a representative cost of $1,800 per ton (2016$).[12] It is at this control stringency where incremental EGU NOx reduction potential and corresponding downwind ozone air quality improvements are maximized relative to the alternative options analyzed. This strategy maximizes the ratio of emission reductions to representative cost and the ratio of ozone improvements to marginal cost. EPA finds that these cost-effective EGU NOx reductions will make meaningful and timely improvements in downwind ozone air quality to address interstate ozone transport for the 2008 ozone NAAQS, as discussed in Section VI.D.1 of the preamble. Further, this evaluation shows that emission budgets reflecting the $1,800 per ton cost threshold do not over-control upwind states' emissions relative to either the downwind air quality problems to which they are linked at step 1 or the 1 percent contribution threshold that triggers further evaluation at step 2 of the 4-step Interstate Transport Framework for the 2008 ozone NAAQS.

In applying the multi-factor test, EPA evaluated whether reductions resulting from the emissions budgets for EGUs in 2021 and 2022 would resolve any downwind nonattainment or maintenance problems. The assessment showed that the emission budgets reflecting $1,800 per ton would change the status of one of the two nonattainment receptors (first shifting the Stratford, Connecticut monitor to a maintenance-only receptor in 2021, then shifting that receptor to attainment in 2022); however, no other nonattainment or maintenance problems

[11] EPA's *Guidelines for Preparing Economic Analysis* states "[a] policy is cost-effective if it meets a given goal at least cost, but cost-effectiveness does not encompass an evaluation of whether that goal has been set appropriately to maximize social welfare. … A policy is considered cost-effective when marginal abatement costs are equal across all polluters. In other words, for any level of total abatement, each polluter has the same cost for their last unit abated." (USEPA 2010, p 4-2). That is not the sense in which the term "cost-effective" is used in this paragraph. For the sense of what this term means, and in particular what "maximize cost-effective reductions" means in the context of this rulemaking, see Section VI.D.1 of the preamble.

[12] EGU NO_X Mitigation Strategies Final Rule TSD, in the docket for this rule (Docket ID No. EPA-HQ-OAR-2020-0272).

would be resolved in 2021 or 2022. EPA's assessment shows that none of the 11 states are solely linked to the Stratford receptor that is resolved at the $1,800 per ton level of control stringency in 2022. In addition, reductions resulting from the $1,800 per ton emission budgets would shift the Houston receptor in Harris County, Texas from maintenance to attainment in 2023. These emission reductions would also shift the last remaining nonattainment receptor (the Westport receptor in Fairfield, Connecticut) to a maintenance-only receptor in 2024. No nonattainment or maintenance receptors would remain after 2024.

1.2.2 States Covered by the Rule

This rule finds that the following 12 states require further ozone season NOx emission reductions to address the good neighbor provision as to the 2008 ozone NAAQS: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia.[13] As such, EPA promulgates FIPs for these states that include new EGU NOx ozone season emission budgets, with implementation of these emission budgets beginning with the 2021 ozone season. EPA also adjusts states' emission budgets for each ozone season thereafter to incentivize ongoing operation of identified emission controls to address significant contribution, until such time that our air quality projections demonstrate anticipated resolution of the downwind nonattainment and/or maintenance problems for the 2008 ozone NAAQS.

1.2.3 Regulated Entities

The rule affects EGUs in these 12 states and regulates utilities (electric, natural gas, other systems) classified as code 221112 by the North American Industry Classification System (NAICS) and have a nameplate capacity of greater than 25 megawatts (MWe).

[13] This action finds that for 9 of the 21 states with remanded FIPs (Alabama, Arkansas, Iowa, Kansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin), their projected 2021 ozone season NOx emissions do not significantly contribute to a continuing downwind nonattainment and/or maintenance problem; therefore the CSAPR Update fully addresses their interstate ozone transport obligations with respect to the 2008 ozone NAAQS. In addition, in the CSAPR Update EPA found that the finalized Tennessee emission budget fully addressed Tennessee's good neighbor obligation with respect to the 2008 ozone NAAQS, and Tennessee is also not considered in this rule. Allowances allocated under the Revised CSAPR Update may not be used for compliance in these 10 Group 2 states that remain subject to the budgets established in the CSAPR Update.

1.2.4 Baseline and Analysis Years

As described in the preamble, EPA aligns implementation of this rule with relevant attainment dates for the 2008 ozone NAAQS. EPA's final 2008 Ozone NAAQS SIP Requirements Rule established the attainment deadline of July 20, 2021 for ozone nonattainment areas currently designated as Serious, and EPA establishes emission budgets and implementation of these emission budgets starting with the 2021 ozone season.

To develop and evaluate control strategies for addressing these obligations, it is important to first establish a baseline projection of air quality in the analysis year of 2021, taking into account currently on-the-books Federal regulations, substantial Federal regulatory proposals, enforcement actions, state regulations, population, and where possible, economic growth.[14] Establishing this baseline for the analysis then allows us to estimate the incremental costs and benefits of the additional emissions reductions that will be achieved by the transport rule.

The baseline for this analysis does not assume states will adopt any emissions reduction methods in and around the Air Quality Control Regions where the nonattainment and maintenance receptors are located to reduce ozone other than those already taken into account. In these areas that do not meet the NAAQS in the baseline that see decreased concentrations of ozone, the states where these receptors are located may be able to avoid applying other measures to assure NAAQS attainment. In this scenario, there would be benefits from avoided compliance costs in these areas and the ozone and $PM_{2.5}$ concentrations changes, and their associated health and ecological benefits, would likely be lower relative to the projections in this RIA. However, the baseline in this RIA respects that NO_X reductions are required of upwind states in order to improve air quality at the nonattainment and maintenance ozone receptors.

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[14] The technical support document (TSD) for the 2016v1 emissions modeling platform titled *Preparation of Emissions Inventories for 2016v1 North American Emissions Modeling Platform* is included in the docket for this rule. The TSD includes additional discussion on mobile source rules included in the baseline. The future year onroad emission factors account for changes in activity data and the impact of on-the-books rules that are implemented into MOVES2014b. These rules include the Light Duty Vehicle GHG Rule for Model-Year 2017-2025 and the Tier 3 Motor Vehicle Emission and Fuel Standards Rule. Local inspection and maintenance (I/M) and other onroad mobile programs are included, such as California LEVIII, the National Low Emissions Vehicle (LEV) and Ozone Transport Commission (OTC) LEV regulations, local fuel programs, and Stage II refueling control programs. Regulations finalized after the year 2014 are not included, such as the Safer Affordable Fuel Efficient (SAFE) Vehicles Final Rule for Model Years 2021-2026 and the Final Rule for Phase 2 Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles.

The analysis in this RIA focuses on benefits, costs and certain impacts from 2021 through 2040. We focus on 2021 because it is by the 2021 ozone season, corresponding with the 2021 Serious area attainment date, that significant contribution from upwind states' must be eliminated to the extent possible. In addition, impacts through 2025 are important because it is in this period that additional NOx control technologies could potentially be installed while upwind linkage to downwind receptors persists. EPA's analysis for the third step of the Interstate Transport Framework indicates that by 2023 the remaining ozone receptors in the two downwind states (Connecticut and Texas) are expected to shift from nonattainment or maintenance status to meeting the NAAQS with application of certain EGU controls beginning in 2021, except for one receptor in Westport, Connecticut.[15] This receptor is estimated to shift from nonattainment status to meeting the NAAQS in 2025 with the application of additional EGU controls. Presenting benefits, costs and certain impacts in 2025 reflects the time needed to make these retrofits on a regional scale and reflects full implementation of the policy. Additional benefits and costs are expected to occur after 2025 as EGUs subject to this rule continue to comply with the tighter allowance budget, which is below their baseline emissions.

1.2.5 Emissions Controls, Emissions, and Cost Analysis Approach

EPA estimated the control strategies and compliance costs of the rule using the Integrated Planning Model (IPM) as well as certain costs that are estimated outside the model but use IPM inputs for their estimation. These cost estimates reflect costs incurred by the power sector and include (but are not limited to) the costs of purchasing, installing, and operating NO_X control technology, changes in fuel costs, and changes in the generation mix.[16] A description of the methodologies used to estimate the costs and economic impacts to the power sector is contained in Chapter 4 of this RIA. This analysis also provides estimates of NO_X emissions changes during

[15] This RIA also provides an assessment of how expected compliance with the rule will affect concentrations at nonattainment and maintenance receptors. See Chapter 4 for additional details.

[16] Under the rule and the more stringent alternative, 10 units are projected to install state-of-the-art combustion controls; under the less stringent alternative, no units are projected to install state-of-the-art combustion controls. Under the rule, the less stringent alternative, and the more stringent alternative, no units are projected to install new SCRs. Under the proposed rule, units were exogenously forced to install SCR controls in IPM. In the modeling for the final rule, the choice to install SCR controls was endogenous to the model, and no incremental SCR installations occurred, with the model relying on greater levels of generation shifting instead.

ozone season and year-round, as well as emissions changes in carbon dioxide (CO_2) due to changes in power sector operation.

1.2.6 Benefits Analysis Approach

Implementing the Revised CSAPR Update rule is expected to reduce emissions of NO_X and provide ozone reductions, as well as consequent reductions in $PM_{2.5}$ concentrations and CO_2 emissions. In the proposed Revised CSAPR Update RIA EPA committed to updating its approach for quantifying the benefits of changes in $PM_{2.5}$ and ozone in this final Revised CSAPR Update RIA. The updated approach incorporates evidence reported in the recently completed $PM_{2.5}$ and Ozone Integrated Science Assessments and accounts for recommendations from the Science Advisory Board. Detailed descriptions of these updates are available in the Technical Support Document (TSD) for the Final Revised Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Update titled *Estimating PM2.5- and Ozone-Attributable Health Benefits*. For more details on these updates, also see Chapter 5. EPA estimated the climate benefits, and a description of the methodologies used to estimate the climate benefits is also contained in Chapter 5.

1.3 Organization of the Regulatory Impact Analysis

This RIA is organized into the following remaining chapters:

- *Chapter 2: Electric Power Sector Profile.* This chapter describes the electric power sector in detail.
- *Chapter 3*: *Emissions and Air Quality Modeling Impacts*. The data, tools, and methodology used for the air quality modeling are described in this chapter, as well as the post-processing techniques used to produce a number of air quality metrics for input into the analysis of benefits.
- *Chapter 4: Cost, Emissions, and Energy Impacts.* The chapter summarizes the data sources and methodology used to estimate the costs and other impacts incurred by the power sector.
- *Chapter 5: Benefits*. The chapter presents the health-related benefits of the ozone and $PM_{2.5}$-related air quality improvements as well as the climate benefits.
- *Chapter 6*: *Statutory and Executive Order Impact Analyses*. The chapter summarizes the Statutory and Executive Order impact analyses.
- *Chapter 7: Comparison of Benefits and Costs*. The chapter compares estimates of the total benefits with total costs and summarizes the net benefits of the three alternative regulatory control scenarios analyzed.

CHAPTER 2: ELECTRIC POWER SECTOR PROFILE

Overview

This chapter discusses important aspects of the power sector that relate to the Revised CSAPR Update with respect to the interstate transport of emissions of nitrogen oxides (NO_X) that contribute significantly to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states. This chapter describes types of existing power-sector sources affected by the regulation[1] and provides background on the power sector and electricity generating units (EGUs). In addition, this chapter provides some historical background on recent trends in the power sector, as well as about existing EPA regulation of the power sector.

2.1 Background

In the past decade there have been significant structural changes in both the mix of generating capacity and in the share of electricity generation supplied by different types of generation. These changes are the result of multiple factors in the power sector, including normal replacements of older generating units with new units, changes in the electricity intensity of the U.S. economy, growth and regional changes in the U.S. population, technological improvements in electricity generation from both existing and new units, changes in the prices and availability of different fuels, and substantial growth in electricity generation by renewable and unconventional methods. Many of these trends will continue to contribute to the evolution of the power sector. The evolving economics of the power sector, specifically the increased natural gas supply and subsequent relatively low natural gas prices, have resulted in more natural gas being used as base load energy in addition to supplying electricity during peak load. This chapter presents data on the evolution of the power sector from 2014 through 2018. Projections of future power sector behavior and the impact of this rule are discussed in more detail in Chapter 4 of this RIA.

2.2 Power Sector Overview

The production and delivery of electricity to customers consists of three distinct segments: generation, transmission, and distribution.

[1] Only coal-fired EGUs will be directly affected (i.e., have to reduce NOx emissions) by this rule.

2.2.1 Generation

Electricity generation is the first process in the delivery of electricity to consumers. There are two important aspects of electricity generation: capacity and net generation. *Generating Capacity* refers to the maximum amount of production an EGU is capable of producing in a typical hour, typically measured in megawatts (MW) for individual units, or gigawatts (1 GW = 1,000 MW) for multiple EGUs. *Electricity Generation* refers to the amount of electricity actually produced by an EGU over some period of time, measured in kilowatt-hours (kWh) or gigawatt-hours (GWh = 1 million kWh). Net Generation is the amount of electricity that is available to the grid from the EGU (i.e., excluding the amount of electricity generated but used within the generating station for operations). Electricity generation is most often reported as the total annual generation (or some other period, such as seasonal). In addition to producing electricity for sale to the grid, EGUs perform other services important to reliable electricity supply, such as providing backup generating capacity in the event of unexpected changes in demand or unexpected changes in the availability of other generators. Other important services provided by generators include facilitating the regulation of the voltage of supplied generation.

Individual EGUs are not used to generate electricity 100 percent of the time. Individual EGUs are periodically not needed to meet the regular daily and seasonal fluctuations of electricity demand. Furthermore, EGUs relying on renewable resources such as wind, sunlight and surface water to generate electricity are routinely constrained by the availability of adequate wind, sunlight, or water at different times of the day and season. Units are also unavailable during routine and unanticipated outages for maintenance. These factors result in the mix of generating capacity types available (e.g., the share of capacity of each type of EGU) being substantially different than the mix of the share of total electricity produced by each type of EGU in a given season or year.

Most of the existing capacity generates electricity by creating heat to create high pressure steam that is released to rotate turbines which, in turn, create electricity. Natural gas combined cycle (NGCC) units have two generating components operating from a single source of heat. The first cycle is a gas-fired turbine, which generates electricity directly from the heat of burning natural gas. The second cycle reuses the waste heat from the first cycle to generate steam, which is then used to generate electricity from a steam turbine. Other EGUs generate electricity by using water or wind to rotate turbines, and a variety of other methods including direct photovoltaic generation also make up a small, but growing, share of the overall electricity supply. The generating capacity includes fossil-fuel-fired units, nuclear units, and hydroelectric and other renewable sources (see Table 2-1). Table 2-1 also shows the comparison between the generating capacity in 2014 and 2018.

In 2018 the power sector consisted of over 22,000 generating units with a total capacity[2] of 1,095 GW, an increase of 26 GW (or 2 percent) from the capacity in 2014 (1,068 GW). The 26 GW increase consisted primarily of natural gas fired EGUs (38 GW), and wind (30 GW) and solar generators (22 GW), and the retirement/re-rating of 56 GW of coal capacity. Substantially smaller net increases and decreases in other types of generating units also occurred.

Table 2-1. Total Net Summer Electricity Generating Capacity by Energy Source, 2014 and 2018

	2014		2018		Change Between '14 and '18		
Energy Source	**Net Summer Capacity (MW)**	**% Total Capacity**	**Net Summer Capacity (MW)**	**% Total Capacity**	**% Increase**	**Capacity Change (MW)**	**% of Total Capacity Increase**
Coal	299,094	28%	242,786	22%	-19%	-56,309	-214%
Natural Gas	432,150	40%	470,237	43%	9%	38,087	145%
Nuclear	98,569	9%	99,433	9%	0.9%	864	3.3%
Hydro	102,162	9.56%	102,702	9.38%	0.5%	540	2.1%
Petroleum	41,135	3.85%	32,218	2.94%	-22%	-8,917	-34%
Wind	64,232	6.01%	94,418	8.62%	47%	30,186	115%
Solar	10,323	0.97%	31,878	2.91%	209%	21,555	82%
Other Renewable	16,049	2%	16,178	1%	1%	129	0%
Misc	4,707	0.44%	4,891	0.45%	4%	184	1%
Total	1,068,422	100%	1,094,740	100%	2%	26,318	100%

Note: This table presents generation capacity. Actual net generation is presented in Table 2-2.
Source: EIA. Electric Power Annual 2014 and 2018, Table 4.3

The 2 percent increase in generating capacity is the net impact of newly built generating units, retirements of generating units, and a variety of increases and decreases to the nameplate

[2] This includes generating capacity at EGUs primarily operated to supply electricity to the grid and combined heat and power facilities classified as Independent Power Producers (IPP) and excludes generating capacity at commercial and industrial facilities that does not operate primarily as an EGU. Natural Gas information in this chapter (unless otherwise stated) reflects data for all generating units using natural gas as the primary fossil heat source. This includes Combined Cycle Combustion Turbine, Gas Turbine, steam, and miscellaneous (< 1 percent).

capacity of individual existing units due to changes in operating equipment, changes in emission controls, etc. During the period 2014 to 2018, a total of 98 GW of new generating capacity was built and brought online, and 74 GW of existing units were retired. The net effect of the re-rating of existing units reduced the total capacity by 9.4 GW. The overall net change in capacity was an increase of 26 GW, as shown in Table 2-1.

The newly built generating capacity was primarily natural gas (44 GW), which was partially offset by gas retirements (24 GW). Wind capacity was the second largest type of new builds (30 GW), augmented by solar (21 GW). The largest decline was from coal retirements and re-rating, which amounted to 56 GW over this period. The overall mix of newly built and retired capacity, along with the net effect, is shown on Figure 2-1. The data for Figure 2-1 is from Form EIA-860. Figure 2-1 does not show wind and solar retirements of 568 MW.

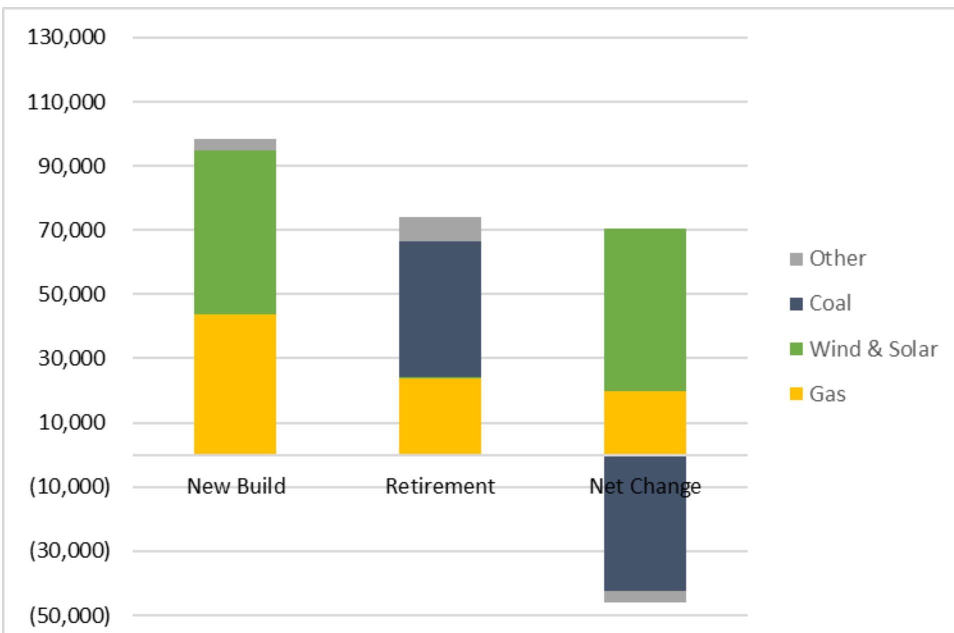

Figure 2-1. National New Build and Retired Capacity (MW) by Fuel Type, 2014-2018

The information in Table 2-1 and Figure 2-1 present information about the generating capacity in the entire U.S. The CSAPR Update, however, directly affected EGUs in 23 eastern states (i.e., the CSAPR 2008 Ozone Region). The share of generating capacity from each major type of generation differs between the CSAPR 2008 Ozone Region and the rest of the U.S. (nonregion). Figure 2-2 shows the mix of generating capacity for each region. In 2018, the overall capacity in the CSAPR 2008 Ozone Region is 59 percent of the national total, reflecting the larger total population in the region. The mix of capacity is noticeably different in the two regions. In the CSAPR 2008 Ozone Region in 2014, coal makes up a significantly larger share of total capacity (26 percent) than it does in the rest of the country (17 percent). The share of natural gas in the CSAPR 2008 Ozone Region is 45 percent as compared to 40 percent in the rest of the country. The difference in the share of coal's capacity is primarily balanced by relatively more hydro, wind, and solar capacity in the rest of country compared to the CSAPR 2008 Ozone Region.

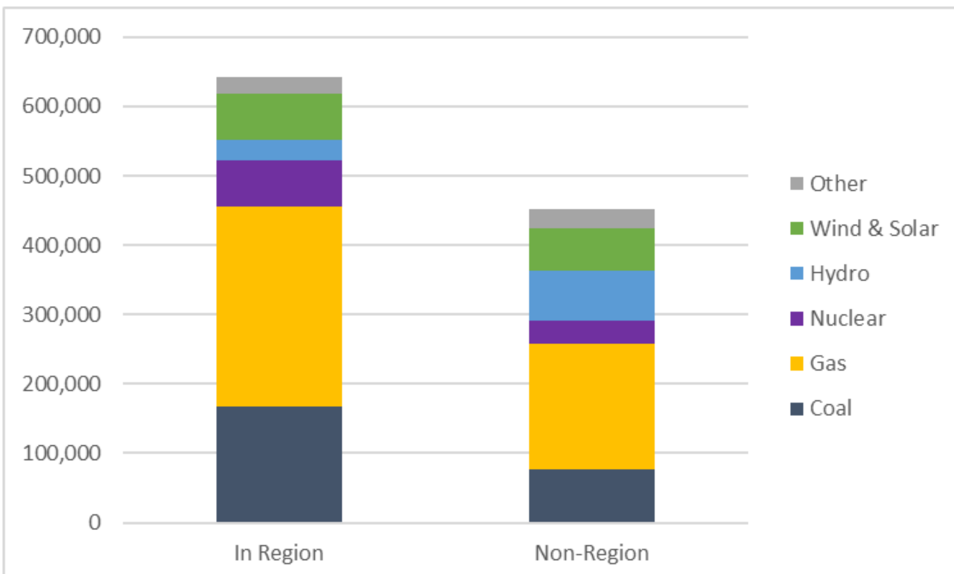

Figure 2-2. Regional Differences in Generating Capacity (MW), 2018

Source: Form EIA-860. Note: "Other" includes petroleum, geothermal, other renewable, waste materials and miscellaneous.

In 2018, electric generating sources produced a net 4,204 TWh to meet national electricity demand, a 2 percent increase from 2014. As presented in Table 2-2, 62 percent of electricity in 2018 was produced through the combustion of fossil fuels, primarily coal and natural gas, with natural gas accounting for the largest single share. Although the share of the total generation from fossil fuels in 2018 (62 percent) was only modestly smaller than the total fossil share in 2014 (66 percent), the mix of fossil fuel generation changed substantially during that period. Coal generation declined by 28 percent and petroleum generation by 17 percent, while natural gas generation increased by 30 percent. This reflects both the increase in natural gas capacity during that period as well as an increase in the utilization of new and existing gas EGUs during that period. Wind and solar generation also grew from 5 percent of the mix in 2014 to 8 percent in 2018.

Table 2-2. Net Generation in 2014 and 2018 (Trillion kWh = TWh)

	2014		2018		Change Between '14 and '18	
	Net Generation (TWh)	Fuel Source Share	Net Generation (TWh)	Fuel Source Share	Net Generation Change (TWh)	% Change in Net Generation
Coal	1,582	39%	1,146	27%	-436	-440%
Natural Gas	1,127	27%	1,469	35%	342	345%
Nuclear	797	19%	807	19%	10	10%
Hydro	253	6%	287	7%	33	34%
Petroleum	30	1%	25	1%	-5	-5%
Wind	182	4%	273	6%	91	92%
Solar	18	0%	64	2%	46	47%
Other Renewable	91	2%	107	3%	16	16%
Misc	25	1%	26	1%	1	1%
Total	4,105	100%	4,204	100%	99	100%

Source: EIA 2014 and 2018 Electric Power Annual, Tables 3.2 and 3.3.

Coal-fired and nuclear generating units have historically supplied “base load” electricity, the portion of electricity loads that are continually present and typically operate throughout all hours of the year. The coal units meet the part of demand that is relatively constant. Although much of the coal fleet operates as base load, there can be notable differences across various facilities (see Table 2-3). For example, coal-fired units less than 100 megawatts (MW) in size compose 18 percent of the total number of coal-fired units, but only 2 percent of total coal-fired capacity. Gas-fired generation is better able to vary output and is the primary option used to meet the variable portion of the electricity load and has historically supplied “peak” and “intermediate” power, when there is increased demand for electricity (for example, when businesses operate throughout the day or when people return home from work and run appliances and heating/air-conditioning), versus late at night or very early in the morning, when demand for electricity is reduced.

Table 2-3 also shows comparable data for the capacity and age distribution of natural gas units. Compared with the fleet of coal EGUs, the natural gas fleet of EGUs is generally smaller and newer. While 66 percent of the coal EGU fleet capacity is over 500 MW per unit, 82 percent of the gas fleet is between 50 and 500 MW per unit. Many of the largest gas units are gas-fired steam-generating EGUs.

Table 2-3. Coal and Natural Gas Generating Units, by Size, Age, Capacity, and Average Heat Rate in 2018

Unit Size Grouping (MW)	No. Units	% of All Units	Avg. Age	Avg. Net Summer Capacity (MW)	Total Net Summer Capacity (MW)	% Total Capacity	Avg. Heat Rate (Btu/kWh)
COAL							
0 – 24	37	7%	50	12	427	0%	11,948
25 – 49	39	7%	34	36	1,404	1%	12,386
50 – 99	26	5%	39	76	1,987	1%	12,027
100 - 149	39	7%	48	122	4,757	2%	11,223
150 - 249	73	13%	50	192	14,040	7%	10,882
250 - 499	142	25%	41	364	51,748	24%	10,659
500 - 749	143	26%	39	608	87,005	40%	10,310
750 - 999	49	9%	35	827	40,521	19%	10,057
1000 - 1500	11	2%	41	1,257	13,831	6%	9,802
Total Coal	559	100%	41	386	215,720	100%	10,838
NATURAL GAS							
0 – 24	3,910	51%	32	5	20,540	4%	14,015
25 – 49	931	12%	26	41	37,792	8%	11,999
50 – 99	1,032	14%	26	71	73,129	15%	12,315
100 - 149	418	5%	22	127	52,927	11%	9,442
150 - 249	1,018	13%	16	179	181,772	38%	8,192
250 - 499	247	3%	22	332	82,114	17%	8,296
500 - 749	38	0%	39	577	21,910	5%	10,583
750 - 1000	9	0%	44	834	7,510	2%	11,625
Total Gas	7,603	100%	28	63	477,693	100%	12,301

Source: National Electric Energy Data System (NEEDS) v.6

Note: The average heat rate reported is the mean of the heat rate of the units in each size category (as opposed to a generation-weighted or capacity-weighted average heat rate.) A lower heat rate indicates a higher level of fuel efficiency. Table is limited to coal-steam units in operation in 2018 or earlier and excludes those units in NEEDS with planned retirements in 2019 or 2020.

In In terms of the age of the generating units, almost 50 percent of the total coal generating capacity has been in service for more than 40 years, while nearly 50 percent of the natural gas capacity has been in service less than 15 years. Figure 2-3 presents the cumulative age distributions of the coal and gas fleets, highlighting the pronounced differences in the ages of the fleets of these two types of fossil-fuel generating capacity. Figure 2-3 also includes the distribution of generation

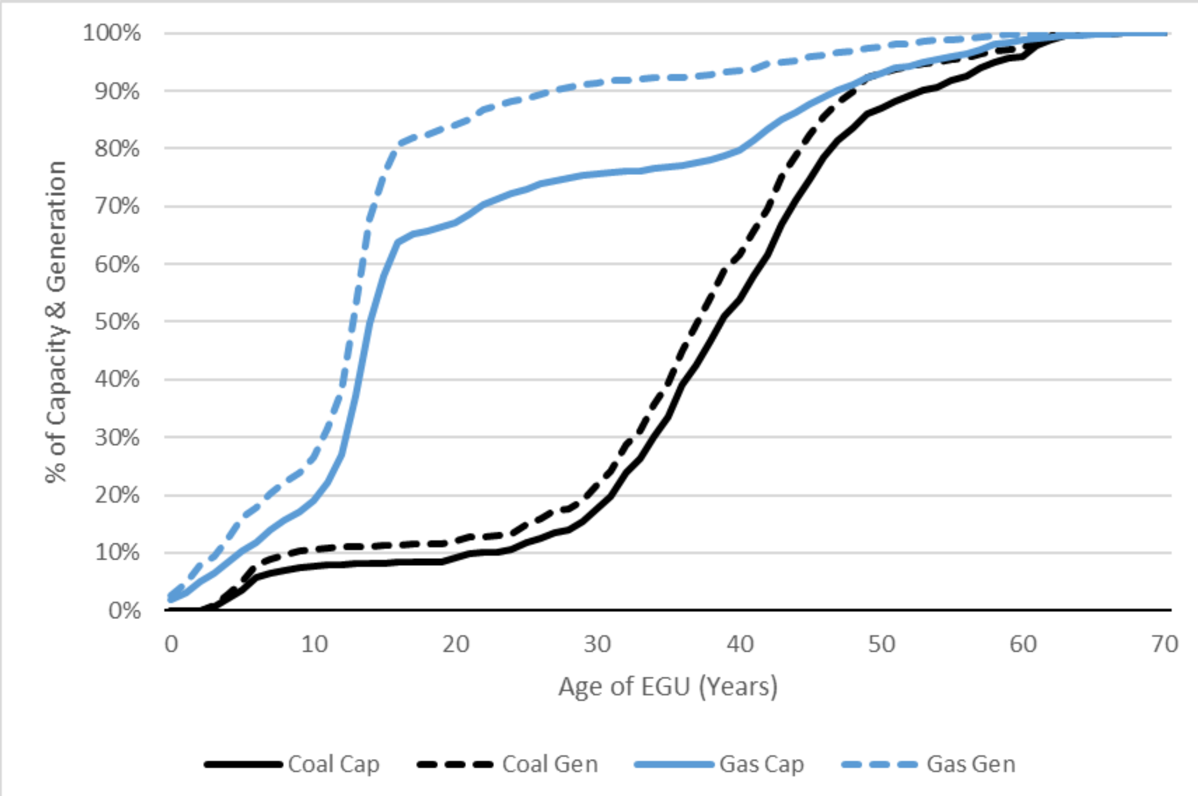

Figure 2-3. Cumulative Distribution in 2018 of Coal and Natural Gas Electricity Capacity and Generation, by Age

Source: eGRID 2018 (March 2020 release from EPA eGRID website). Figure presents data from generators that came online between 1949 and 2018 (inclusive); a 70-year period. Full eGrid data includes generators that came online as far back as 1915. Full data from 1915 onward is used in calculating cumulative distributions; figure truncation at 70 years is merely to improve visibility of diagram. Figure is limited to coal-steam units in NEEDS v6 in operation in 2018 or earlier.

The locations of existing fossil units in EPA's National Electric Energy Data System (NEEDS) v.6 are shown in Figure 2-4.

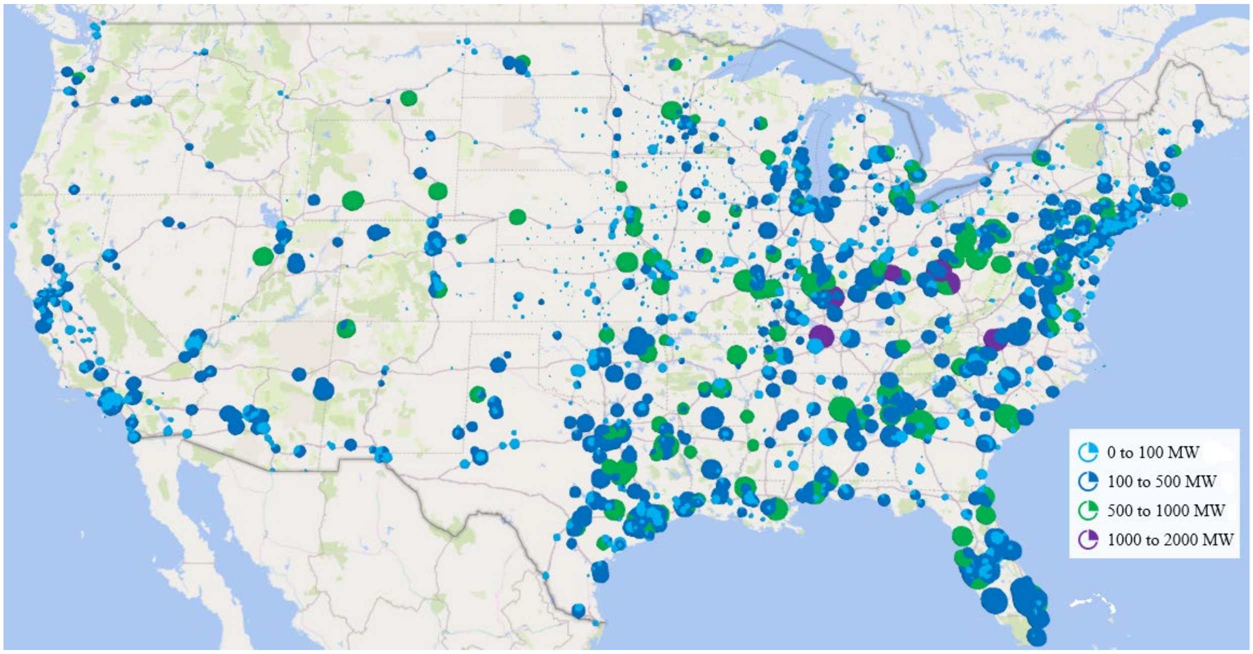

Figure 2-4. Fossil Fuel-Fired Electricity Generating Facilities, by Size

Source: National Electric Energy Data System (NEEDS) v.6

Note: This map displays fossil capacity at facilities in the NEEDS v.6 IPM frame. NEEDS v.6 reflects generating capacity expected to be on-line at the end of 2021. This includes planned new builds already under construction and planned retirements. In areas with a dense concentration of facilities, some facilities may be obscured.

2.2.2 Transmission

Transmission is the term used to describe the bulk transfer of electricity over a network of high voltage lines, from electric generators to substations where power is stepped down for local distribution. In the U.S. and Canada, there are three separate interconnected networks of high voltage transmission lines,[3] each operating synchronously. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single

[3] These three network interconnections are the Western Interconnection, comprising the western parts of both the US and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the US and Canada (except those part of eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT)). See map of all NERC interconnections at https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf.

regional operator;[4] in others, individual utilities[5] coordinate the operations of their generation, transmission, and distribution systems to balance the system across their respective service territories.

2.2.3 Distribution

Distribution of electricity involves networks of lower voltage lines and substations that take the higher voltage power from the transmission system and step it down to lower voltage levels to match the needs of customers. The transmission and distribution system is the classic example of a natural monopoly, in part because it is not practical to have more than one set of lines running from the electricity generating sources to substations or from substations to residences and businesses.

Over the last few decades, several jurisdictions in the United States began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. Historically, vertically integrated utilities established much of the existing transmission infrastructure. However, as parts of the country have restructured the industry, transmission infrastructure has also been developed by transmission utilities, electric cooperatives, and merchant transmission companies, among others. Distribution, also historically developed by vertically integrated utilities, is now often managed by a number of utilities that purchase and sell electricity, but do not generate it. As discussed below, electricity restructuring has focused primarily on efforts to reorganize the industry to encourage competition in the generation segment of the industry, including ensuring open access of generation to the transmission and distribution services needed to deliver power to consumers. In many states, such efforts have also included separating generation assets from transmission and distribution assets to form distinct economic entities. Transmission and distribution remain price-regulated throughout the country based on the cost of service.

2.3 Sales, Expenses, and Prices

These electric generating sources provide electricity for ultimate commercial, industrial and residential customers. Each of the three major ultimate categories consume roughly a quarter

[4] For example, PMJ Interconnection, LLC, Western Area Power Administration (which comprises 4 sub-regions).
[5] For example, Los Angeles Department of Power and Water, Florida Power and Light.

to a third of the total electricity produced[6] (see Table 2-4). Some of these uses are highly variable, such as heating and air conditioning in residential and commercial buildings, while others are relatively constant, such as industrial processes that operate 24 hours a day. The distribution between the end use categories changed very little between 2014 and 2018.

Table 2-4. Total U.S. Electric Power Industry Retail Sales, 2014 and 2018 (billion kWh)

		2014		2018	
		Sales/Direct Use (Billion kWh)	**Share of Total End Use**	**Sales/Direct Use (Billion kWh)**	**Share of Total End Use**
Sales	Residential	1,407	36%	1,469	37%
	Commercial	1,352	35%	1,382	35%
	Industrial	998	26%	1,001	25%
	Transportation	8	0%	8	0%
Total		3,765	96%	3,859	96%
Direct Use		139	4%	144	4%
Total End Use		3,903	100%	4,003	100%

Source: Table 2.2, EIA Electric Power Annual, 2014 and 2018
Notes: Retail sales are not equal to net generation (Table 2-2) because net generation includes net imported electricity and loss of electricity that occurs through transmission and distribution, along with data collection frame differences and non-sampling error. Direct Use represents commercial and industrial facility use of onsite net electricity generation; electricity sales or transfers to adjacent or co-located facilities; and barter transactions.

2.3.1 Electricity Prices

Electricity prices vary substantially across the United States, differing both between the ultimate customer categories and by state and region of the country. Electricity prices are typically highest for residential and commercial customers because of the relatively high costs of distributing electricity to individual homes and commercial establishments. The higher prices for residential and commercial customers are the result both of the necessary extensive distribution network reaching to virtually every part of the country and every building, and also the fact that generating stations are increasingly located relatively far from population centers (which increases transmission costs). Industrial customers generally pay the lowest average prices, reflecting both their proximity to generating stations and the fact that industrial customers

[6] Transportation (primarily urban and regional electrical trains) is a fourth ultimate customer category which accounts for less than one percent of electricity consumption.

receive electricity at higher voltages (which makes transmission more efficient and less expensive). Industrial customers frequently pay variable prices for electricity, varying by the season and time of day, while residential and commercial prices historically have been less variable. Overall industrial customer prices are usually considerably closer to the wholesale marginal cost of generating electricity than residential and commercial prices.

On a state-by-state basis, all retail electricity prices vary considerably. In 2018, the national average retail electricity price (all sectors) was 10.53 cents/KWh, with a range from 7.71 cents (Louisiana) to 29.18 (Hawaii).[7]

Average national retail electricity prices decreased between 2014 and 2018 by 5 percent in real terms (2018$).[8] The amount of decrease differed for the three major end use categories (residential, commercial and industrial). National average industrial prices decreased the most (9 percent), and residential prices decreased the least (4 percent). The real year prices for 2014 through 2019 are shown in Figure 2-5.

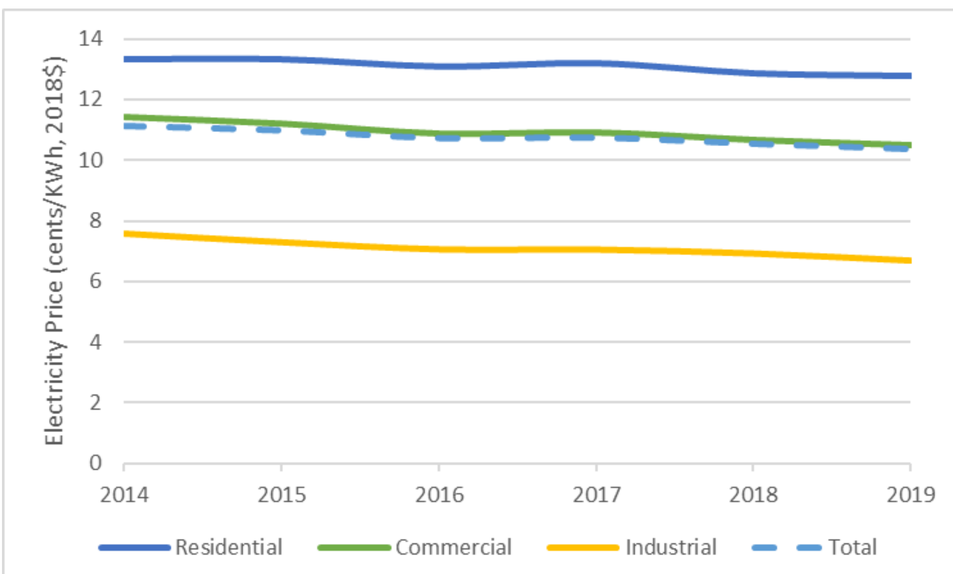

Figure 2-5. Real National Average Electricity Prices (including taxes) for Three Major End-Use Categories

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[7] EIA State Electricity Profiles with Data for 2019 (http://www.eia.gov/electricity/state/)

[8] All prices in this section are estimated as real 2018 prices adjusted using the GDP implicit price deflator unless otherwise indicated.

Source: EIA Monthly Energy Review (Feb 2021), Table 9.8.

Most of these electricity price decreases occurred between 2014 and 2015, when nominal residential electricity prices followed inflation trends, while nominal commercial and industrial electricity prices declined. The years 2016 and 2017 saw an increase in nominal commercial and industrial electricity prices, while 2018 saw flattening of this growth. The increase in nominal electricity prices for the major end use categories, as well as increases in the GDP price and CPI-U indices for comparison, are shown in Figure 2-6.

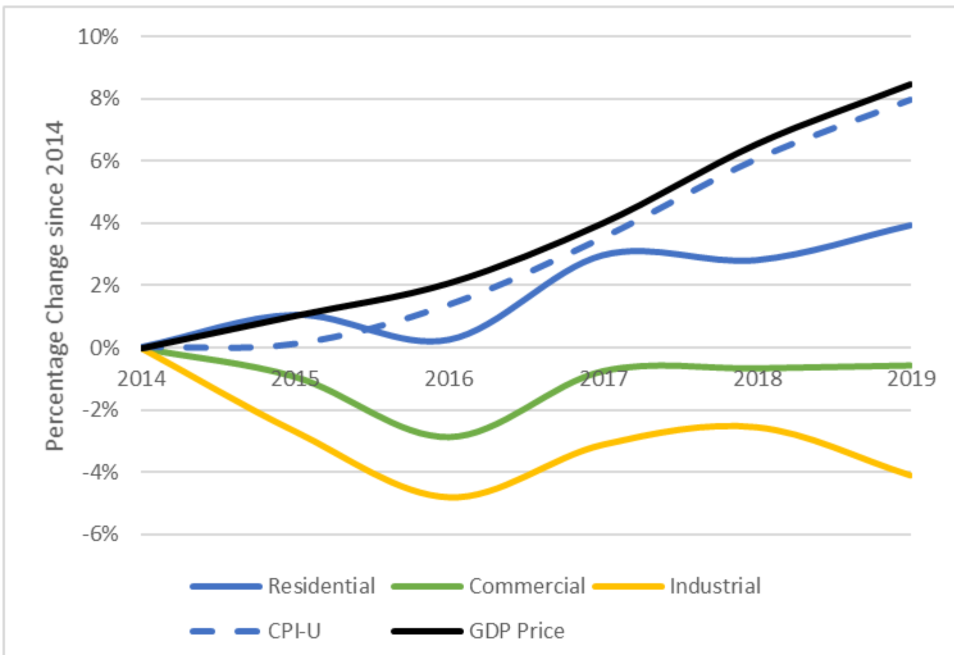


Figure 2-6. Relative Increases in Nominal National Average Electricity Prices for Major End-Use Categories (including taxes), With Inflation Indices

Source: EIA Monthly Energy Review (Feb 2021), Table 9.8.

For a longer-term perspective, Figure 2-7 shows real[9] (2018$) electricity prices for the three major customer categories since 1960, and Figure 2-8 shows the relative change in real electricity prices relative to the prices since 1960. As can be seen in the figures, the price for industrial customers has always been lower than for either residential or commercial customers, but the industrial price has been more volatile. While the industrial real price of electricity in

[9] All prices in this section are estimated as real 2018 prices adjusted using the GDP implicit price deflator unless otherwise indicated.

2018 was relatively unchanged from 1960 (5 percent lower), residential and commercial real prices are 25 percent and 33 percent lower respectively than in 1960.

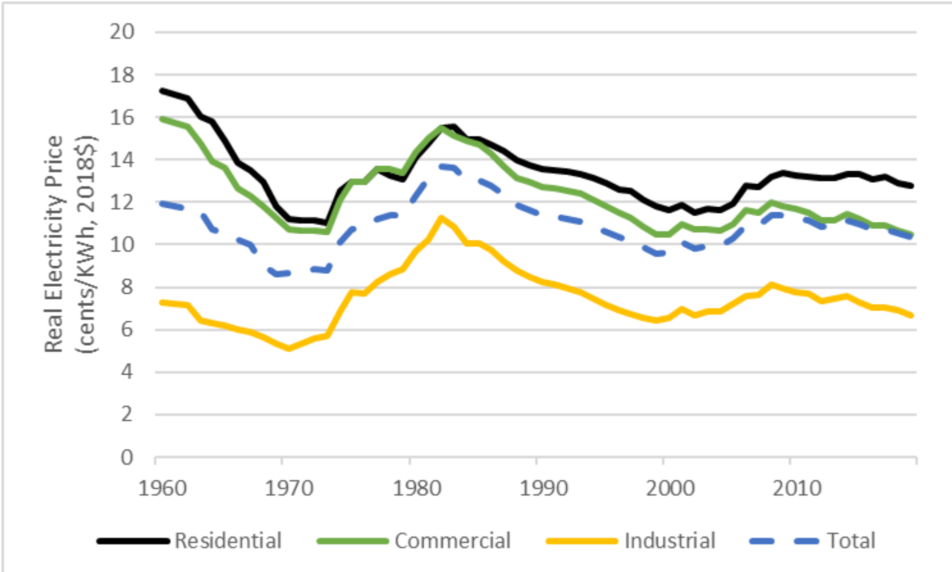


Figure 2-7. Real National Average Electricity Prices for Three Major End-Use Categories (including taxes), 1960-2019 (2018$)

Source: EIA Monthly Energy Review, Feb 2021, Table 9.8

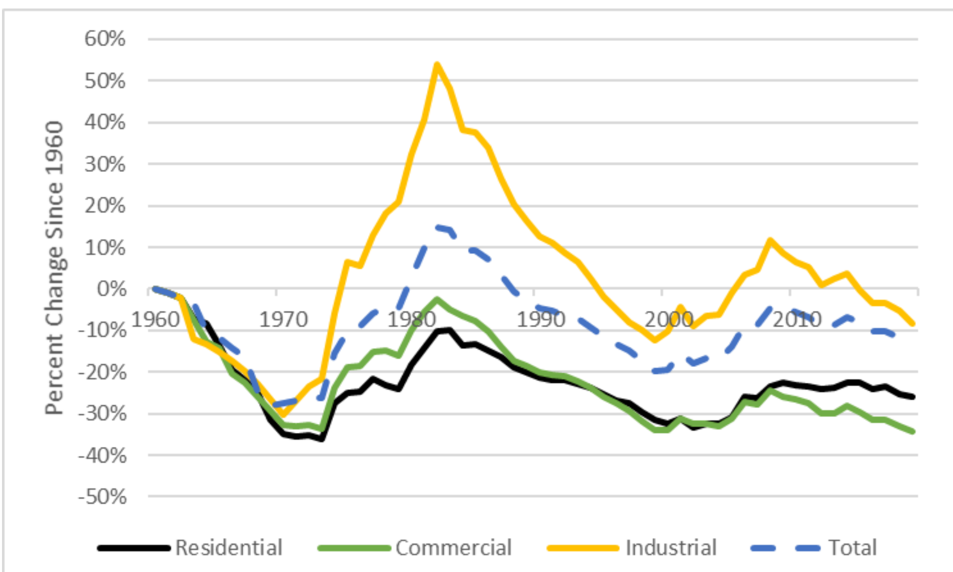


Figure 2-8. Relative Change in Real National Average Electricity Prices (2018$) for Three Major End-Use Categories (including taxes)

Source: EIA Monthly Energy Review, Feb 2021, Table 9.8.

2.3.2 *Prices of Fossil Fuels Used for Generating Electricity*

Another important factor in the changes in electricity prices are the changes in delivered fuel prices[10] for the three major fossil fuels used in electricity generation: coal, natural gas and petroleum products. Relative to real prices in 2014, the national average real price (in 2018$) of coal delivered to EGUs in 2018 had decreased by 18 percent, while the real price of natural gas decreased by 33 percent. The real price of delivered petroleum products also decreased by 22 percent, but with petroleum products declining as an EGU fuel (in 2018 petroleum products generated 1 percent of electricity) the higher delivered oil prices had little overall impact in the electricity market. The combined real delivered price of all fossil fuels in 2014 decreased by 20 percent over 2014 prices. Figure 2-9 shows the relative changes in real price of all 3 fossil fuels between 2014 and 2019.

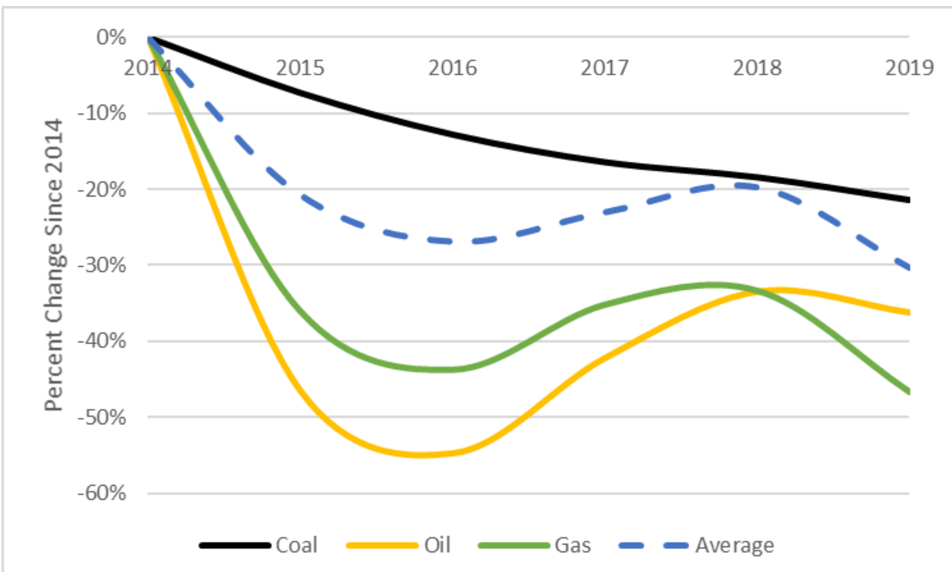


Figure 2-9. Relative Real Prices of Fossil Fuels for Electricity Generation; Change in National Average Real Price per MMBtu Delivered to EGU

Source: EIA Monthly Energy Review, Feb 2021, Table 9.9.

[10] Fuel prices in this section are all presented in terms of price per MMBtu to make the prices comparable.

2.3.3 Changes in Electricity Intensity of the U.S. Economy from 2014 to 2018

An important aspect of the changes in electricity generation (i.e., electricity demand) between 2014 and 2018 is that while total net generation increased by 2 percent over that period, the demand growth for generation was lower than both the population growth (3 percent) and real GDP growth (10 percent). Figure 2-10 shows the growth of electricity generation, population and real GDP during this period.

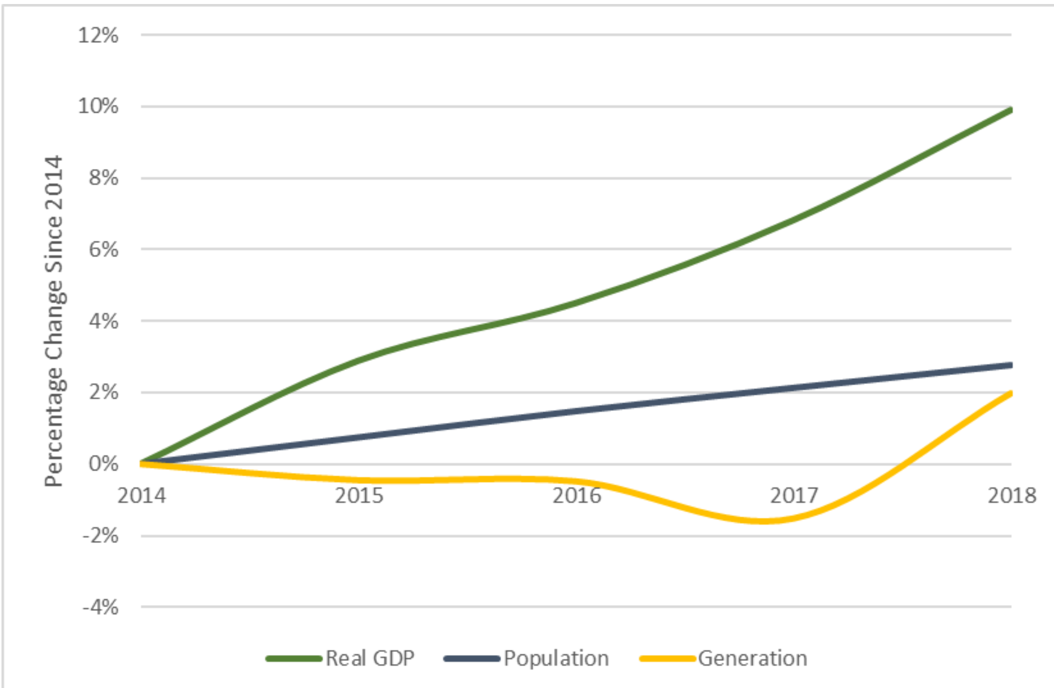


Figure 2-10. Relative Growth of Electricity Generation, Population and Real GDP Since 2014

Sources: Generation: U.S. EIA Monthly Energy Review, May 2020. Table 7.2a Electricity Net Generation: Total (All Sectors). Population: U.S. Census. Real GDP: 2019 Economic Report of the President, Table B-3.

Because demand for electricity generation grew more slowly than both the population and GDP, the relative electric intensity of the U.S. economy improved (i.e., less electricity used per person and per real dollar of output) during 2014 to 2018. On a per capita basis, real GDP per capita grew by 7 percent between 2014 and 2018. At the same time electricity generation per capita decreased by 1 percent. The combined effect of these two changes improved the overall electricity generation efficiency in the U.S. market economy. Electricity generation per dollar of real GDP decreased 7 percent. These relative changes are shown in Figure 2-11.

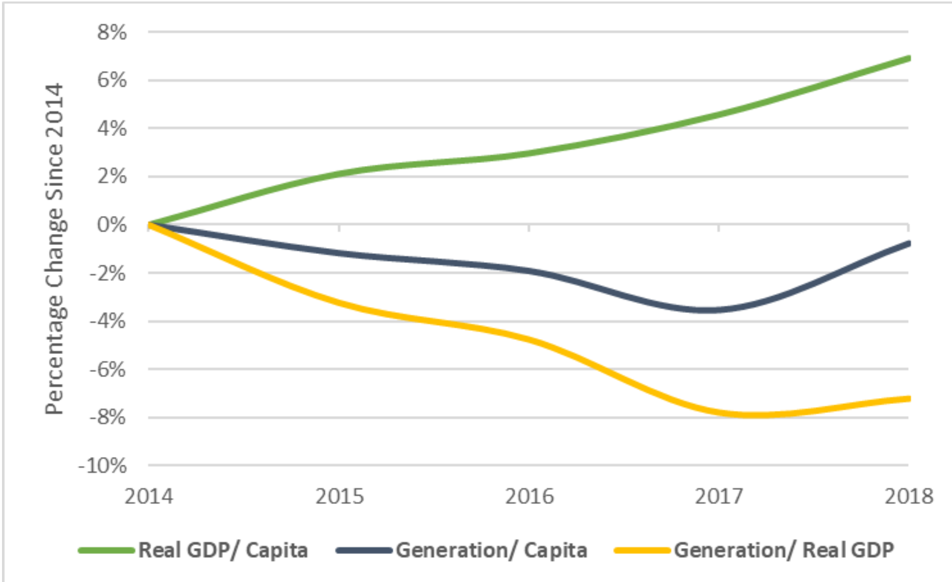


Figure 2-11. Relative Change of Real GDP, Population and Electricity Generation Intensity Since 2014

Sources: Generation: EIA Monthly Energy Review, Feb 2021. Table 7.2a Electricity Net Generation: Total (All Sectors). Population: U.S. Census. Real GDP: 2019 Economic Report of the President, Table B-3.

2.4 Deregulation and Restructuring

The process of restructuring and deregulation of wholesale and retail electricity markets has changed the structure of the electric power industry. In addition to reorganizing asset management between companies, restructuring sought a functional unbundling of the generation, transmission, distribution, and ancillary services the power sector has historically provided, with the aim of enhancing competition in the generation segment of the industry.

Beginning in the 1970s, government policy shifted against traditional regulatory approaches and in favor of deregulation for many important industries, including transportation (notably commercial airlines), communications, and energy, which were all thought to be natural monopolies (prior to 1970) that warranted governmental control of pricing. However, deregulation efforts in the power sector were most active during the 1990s. Some of the primary drivers for deregulation of electric power included the desire for more efficient investment choices, the economic incentive to provide least-cost electric rates through market competition, reduced costs of combustion turbine technology that opened the door for more companies to sell power with smaller investments, and complexity of monitoring utilities' cost of service and establishing cost-based rates for various customer classes. Deregulation and market restructuring in the power sector involved the divestiture of generation from utilities, the formation of organized wholesale spot energy markets with economic mechanisms for the rationing of scarce transmission resources during periods of peak demand, the introduction of retail choice programs, and the establishment of new forms of market oversight and coordination.

The pace of restructuring in the electric power industry slowed significantly in response to market volatility in California and financial turmoil associated with bankruptcy filings of key energy companies. Currently, there are 15 states plus the District of Columbia where price deregulation of generation (restructuring) has occurred ("Active" in Figure 2-12). Power sector restructuring is more or less at a standstill; by 2010 there were no active proposals under review by the Federal Energy Regulatory Commission (FERC) for actions aimed at wider restructuring, and no additional states have begun retail deregulation activity since that time.

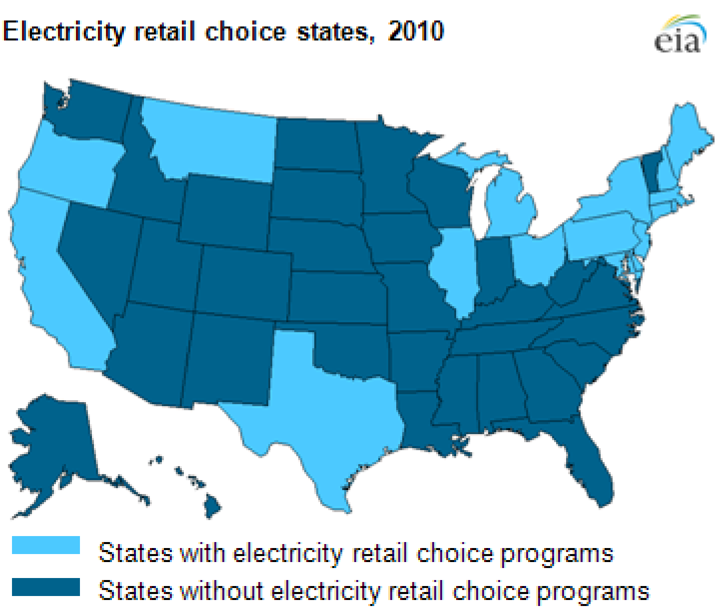


Figure 2-12. Status of State Electricity Industry Restructuring Activities

Source: EIA 2010. "Status of Electricity Restructuring by State." Available online at: <https://www.eia.gov/todayinenergy/detail.php?id=6250>.

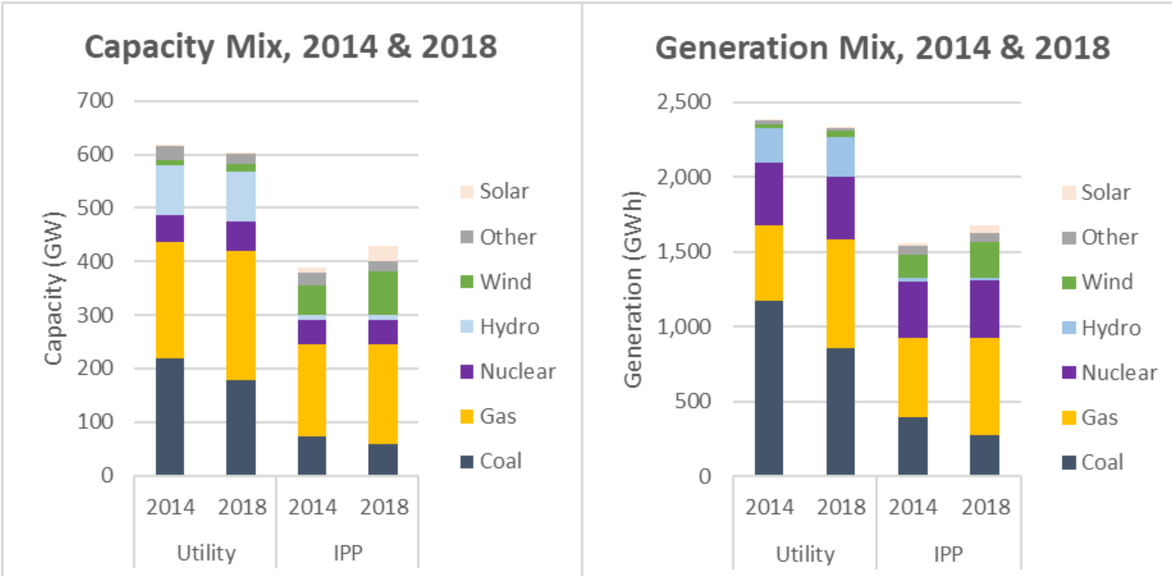
One major effect of the restructuring and deregulation of the power sector was a significant change in type of ownership of electricity generating units in the states that deregulated prices. Throughout most of the 20th century electricity was supplied by vertically integrated regulated utilities. The traditional integrated utilities provided generation, transmission and distribution in their designated areas, and prices were set by cost of service regulations set by state government agencies (e.g., Public Utility Commissions). Deregulation and restructuring resulted in unbundling of the vertical integration structure. Transmission and distribution continued to operate as monopolies with cost of service regulation, while generation shifted to a mix of ownership affiliates of traditional utility ownership and some generation owned and operated by competitive companies known as Independent Power Producers (IPPs). The resulting generating sector differed by state or region, as the power sector adapted to the restructuring and deregulation requirements in each state.

By the year 2000, the major impacts of adapting to changes brought about by deregulation and restructuring during the 1990s were nearing completion. In 2014, traditional utilities owned 61 percent of U.S. generating capacity (MW) while IPPs[11] owned 39 percent of U.S. generating capacity, respectively. The mix of electricity generated (MWh) was more heavily weighted towards the utilities, with a distribution in 2014 of 61 percent, and 39 percent for IPPs.

In 2018, the share of capacity (59 percent utility, 41 percent IPPs) and generation (58 percent utility, 42 percent IPP) has remained relatively stable relative to 2014 levels.

The mix of capacity and generation for each of the ownership types is shown in Figures 2-13 (capacity) and 2-14 (generation). The capacity and generation data for commercial and industrial owners are not shown on these figures due to the small magnitude of those ownership

[11] IPP data presented in this section include both combined and non-combined heat and power plants.



Figures 2-13. and 2-14. Capacity and Generation Mix by Ownership Type, 2014 & 2018

types. A portion of the shift of capacity and generation is due to sales and transfers of generation assets from traditional utilities to IPPs, rather than strictly the result of newly built units.

CHAPTER 3: EMISSIONS AND AIR QUALITY IMPACTS

Overview

This Chapter describes the methods for developing spatial fields of air quality concentrations for the baseline and regulatory control alternatives in 2021 and 2024. These spatial fields provide the air quality inputs to potentially calculate health benefits for the Revised CSAPR Update. The spatial fields for this rule were constructed using the method and air quality modeling developed to support the regulatory impact analysis (RIA) for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (U.S. EPA 2019), also referred to as the Affordable Clean Energy (ACE) rule.[1]

In Section 3.1 we describe the ACE air quality modeling platform; in Section 3.2 we describe the ACE approach for processing the air quality modeling outputs to create inputs for estimating benefits; in Section 3.3 we describe how the ACE approach was applied in the Revised CSAPR Update, in Section 3.4 we present maps showing the impacts on ozone and $PM_{2.5}$ concentrations of each of the three regulatory control alternatives compared to the corresponding baseline; and in Section 3.5 we identify uncertainties and limitations in the application of the ACE approach for generating spatial fields of pollutant concentrations.

3.1 ACE Air Quality Modeling Platform

The air quality modeling for the ACE analysis utilized a 2011-based modeling platform which included meteorology and base year emissions from 2011 and projected emissions for 2023. The air quality modeling included annual photochemical model simulations for a 2011 base year and a 2023 future year to provide hourly concentrations of ozone and primary and secondarily formed $PM_{2.5}$ component species (*e.g.*, sulfate, nitrate, ammonium, elemental carbon (EC), organic aerosol (OA), and crustal material[2]) for both years nationwide. In particular, source apportionment modeling was performed for 2023 to quantify the contributions to ozone and $PM_{2.5}$ component species from coal-fired and non-coal electric generating units (EGUs) on a

[1] Additional details on the ACE modeling and methodology for developing spatial fields of air quality for EGU control strategies are provided in Appendix 3A.

[2] Crustal material refers to metals that are commonly found in the earth's crust such as Aluminum, Calcium, Iron, Magnesium, Manganese, Potassium, Silicon, Titanium and the associated oxygen atoms.

state-by-state or multi-state basis. As described below, the modeling results for 2011 and 2023, in conjunction with emissions data for the baseline and regulatory control alternatives, were used to construct the air quality spatial fields that reflect the influence of emissions changes between the baseline and the regulatory control alternatives.

The air quality model simulations (*i.e.*, model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx) (Ramboll Environ 2016). Our CAMx nationwide modeling domain (*i.e.*, the geographic area included in the modeling) covers all lower 48 states plus adjacent portions of Canada and Mexico using a horizontal grid resolution of 12 x 12 km shown in Figure 3-1.

Figure 3-1. Air Quality Modeling Domain

The impact of specific emissions sources on ozone and $PM_{2.5}$ in the 2023 modeled case was tracked using a tool called "source apportionment." In general, source apportionment modeling quantifies the air quality concentrations formed from individual, user-defined groups of emissions sources or "tags". These source tags are tracked through the transport, dispersion, chemical transformation, and deposition processes within the model to obtain hourly gridded[3] contributions from the emissions in each individual tag to hourly modeled concentrations of ozone and $PM_{2.5}$.[4] Thus, the source apportionment method provides an estimate of the effect of

[3] Hourly contribution information is provided for each grid cell to provide spatial patterns of the contributions from each tag.
[4] Note that the sum of the contributions in a model grid cell from each tag for a pollutant equals the total concentration of that pollutant in the grid cell.

changes in emissions from each group of emissions sources (*i.e.*, each tag) to changes in ozone and $PM_{2.5}$ concentrations. For this analysis we applied outputs from source apportionment modeling for ozone and $PM_{2.5}$ using the 2023 modeled case to obtain the contributions from EGU emissions as well as other sources to ozone and to $PM_{2.5}$ component species concentrations.[5] Ozone contributions were modeled using the Ozone Source Apportionment Technique/Anthropogenic Precursor Culpability Assessment (OSAT/APCA) tool and $PM_{2.5}$ component species contributions were modeled using the Particulate Source Apportionment Technique (PSAT) tool.[6] The source apportionment modeling, which was already available from analysis performed to support the ACE rule RIA (U.S. EPA, 2019) was used to quantify the contributions from EGU emissions on a state-by-state or, in some cases, on a multi-state basis. For ozone, we modeled the contributions from the 2023 EGU sector emissions of NO_X and VOC to hourly ozone concentrations for the period April through October to provide data for developing spatial fields for two seasonal ozone benefits metrics identified above (i.e., for the May-September seasonal average of the maximum daily 8-hour average (MDA8) ozone and the April-October seasonal average of the maximum daily 1-hour average (MDA1) ozone). For $PM_{2.5}$, we modeled the contributions from the 2023 EGU sector emissions of SO_2, NO_X, and directly emitted $PM_{2.5}$ for the entire year to inform the development of spatial fields of annual mean $PM_{2.5}$. For each state, or multi-state group, we separately tagged EGU emissions depending on whether the emissions were from coal-fired units or non-coal units.[7] In addition to tagging coal-fired and non-coal EGU emissions we also tracked the ozone and $PM_{2.5}$ contributions from all other sources.

3.2. Applying Modeling Outputs to Create Spatial Fields

In this section we describe the ACE approach for creating spatial fields based on the 2011 and 2023 modeling performed for the ACE rule. The foundational data from ACE include the ozone contributions from EGU emissions in each state based on the 2023 ACE EGU state-sector sector contribution modeling and the 2023 emissions for coal and non-coal fired EGUs that were

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[5] In the source apportionment modeling for $PM_{2.5}$ we tracked the source contributions from primary, but not secondary organic aerosols (SOA). The method for treating SOA concentrations is described in U.S. EPA, 2019 chapter 8.

[6] OSAT/APCA and PSAT tools are described in Ramboll Environ (2016).

[7] For the purposes of this analysis non-coal fuels include emissions from natural gas, oil, biomass, municipal waste combustion and waste coal EGUs.

input to that modeling. These data are used to generate spatial fields based on ozone season EGU NOx emissions (tons) and annual total EGU emissions of NOx, SO2 and $PM_{2.5}$. The inputs for this method include emissions for each state with a breakout of emissions for coal-fired and non-coal EGUs. The ozone season NOx emissions are used to prepare spatial fields of the May-September seasonal average MDA8 ozone and the April-October seasonal average MDA1 ozone concentration and the annual emissions are used to prepare spatial fields of annual $PM_{2.5}$ concentrations. This method calculates the scaling ratios, described below, that are used to prepare the air quality spatial fields.

To create the spatial fields for each future emissions scenario the 2023 state-sector source apportionment modeling outputs from the ACE modeling described above are used in combination with the EGU SO_2, NO_x, and $PM_{2.5}$ emissions for each scenario. Contributions from each state-sector contribution "tag" were scaled based on the ratio of emissions in the year/scenario being evaluated to the emissions in the modeled ACE 2023 scenario. In this approach, scaling ratios for $PM_{2.5}$ components that are emitted directly from the source (OA, EC, crustal) are based on relative changes in annual primary $PM_{2.5}$ emissions between the modeled ACE 2023 emissions scenario and the specific baseline or control scenario being analyzed. Also the scaling ratios for components that are formed through chemical reactions in the atmosphere were created as follows: scaling ratios for sulfate were based on relative changes in annual SO_2 emissions; scaling ratios for nitrate were based on relative changes in annual NO_X emissions; and scaling ratios for ozone formed in NO_X-limited regimes[8] ("O3N") were based on relative changes in ozone season (May-September) NO_X emissions. Tags representing sources other than EGUs are held constant at 2023 ACE baseline levels for emissions scenarios analyzed by the user. For each control scenario analyzed, the scaled contributions from all sources were summed together to create a gridded surface of total modeled ozone or total modeled $PM_{2.5}$. Finally, spatial fields of ozone and $PM_{2.5}$ are created based on "fusing" modeled data with measured concentrations at air quality monitoring locations. The process is described in a step-by-step manner below.

(1) The EGU annual SO_2, NO_X, and directly emitted $PM_{2.5}$ emissions for the control scenario of interest and the corresponding 2023 SO_2, NO_X, and directly emitted $PM_{2.5}$ emissions

[8] The CAMx model internally determines whether the ozone formation regime is NO_X-limited or VOC-limited depending on predicted ratios of indicator chemical species.

used in the ACE modeling to calculate the ratio of control case emissions to the ACE emissions for each of these pollutants for each EGU tag.

(2) The tag-specific 2024 to 2023 EGU emissions-based scaling ratios from step (1) are multiplied by the corresponding 365 gridded daily 24-hour average $PM_{2.5}$ component species contributions from the 2023 contribution modeling. The emissions ratios for SO_2 are applied to sulfate contributions; ratios for annual NO_X are applied to nitrate contributions; and ratios for directly emitted $PM_{2.5}$ are applied to the EGU contributions to primary OA, EC and crustal material. This step results in 365 adjusted gridded daily $PM_{2.5}$ component species contributions for each EGUs tag that reflects the emissions in the control scenario.

(3) For each individual $PM_{2.5}$ component species, the adjusted gridded contributions for each EGU tag from step (2) are added together to produce a gridded daily EGU tag total.

(4) The daily total EGU contributions for each $PM_{2.5}$ component species from step (3) are then combined with the species contributions from source tags representing all other sources of $PM_{2.5}$. As part of this step we also add the total secondary organic aerosol concentrations from the 2023 ACE modeling to the net EGU contributions of primary OA. Note that the secondary organic aerosol concentration does not change between scenarios. This step results in 24-hour average $PM_{2.5}$ component species concentrations for the control scenario in each model grid cell, nationwide for each day in the year.

(5) For each $PM_{2.5}$ component species, the daily concentrations from step (4) are averaged for each quarter of the year.

(6) The quarterly average $PM_{2.5}$ component species concentrations from step (5)[9] are divided by the corresponding quarterly average species concentrations from the base period air quality model run. This step provides a Relative Response Factor (i.e., RRF) between the base period and the control scenario for each species in each model grid cell.

(7) The species-specific quarterly RRFs from step (6) are then multiplied by the corresponding species-specific quarterly average concentrations from the base period

[9] Ammonium concentrations are calculated assuming that the degree of neutralization of sulfate ions remains at 2011 levels (see Chapter 8 of U.S. EPA, 2019 for details).

fused surfaces to produce quarterly average species concentrations for the control scenario.

(8) The quarterly average species concentrations from step (7) are summed over the species to produce total $PM_{2.5}$ concentrations for each quarter. Finally, total $PM_{2.5}$ concentrations for the four quarters of the year are averaged to produce the spatial field of annual average $PM_{2.5}$ concentrations for the 2024 baseline.

To generate the spatial fields for each of the two ozone concentration metrics (i.e., April-October MDA1 and May-September MDA8) we follow the steps similar to those above for $PM_{2.5}$.

(1) The EGU May through September (i.e., Ozone Season - OS) NO_X for the control scenario and the corresponding modeled 2023 OS NO_X emissions are used to calculate the ratio of control scenario emissions to 2023 ACE emissions for each EGU tag (i.e. an ozone-season scaling factor for each tag).

(2) The source apportionment modeling provided separate ozone contributions for ozone formed in VOC-limited chemical regimes (O_3V) and ozone formed in NO_X-limited chemical regimes (O_3N).[10] The EGU OS NOx emissions for the control scenario and the 2023 ACE OS NOx baseline emissions are used to calculate the ratio of the control scenario emissions to the 2023 ACE emission to create the EGU NOx emissions scaling ratios. The emissions scaling ratios are multiplied by the corresponding O_3N gridded daily contributions to MDA1 and MDA8 concentrations. This step results in adjusted gridded daily MDA1 and MDA8 contributions due to NO_X changes for each EGUs tag that reflect the emissions in the 2024 baseline.

(3) For MDA1 and MDA8, the adjusted contributions for each EGU tag from step (2) are added together to produce a daily adjusted EGU tag total. Since IPM does not output VOC from EGUs, there are no predicted changes in VOC emissions in these scenarios so the O_3V contributions remain unchanged. The contributions from the unaltered O_3V tags from the 2023 ACE modeling are added to the summed adjusted O_3N EGU tags.

[10] Information on the treatment of ozone contributions under NOx-limited and VOC-limited chemical regimes in the CAMx APCA source apportionment technique can be found in the CAMx v6.40 User's Guide (Ramboll, 2016).

(4) The daily total EGU contributions for MDA1 and MDA8 from step (3) are then combined with the contributions to MDA1 and MDA8 from all other sources. This step results in MDA1 and MDA8 concentrations for the control scenario in each model grid cell, nationwide for each day in the ozone season.

(5) For MDA1, we average the daily concentrations from step (4) across all the days in the period April 1 through October 31. For MDA8, we average the daily concentrations across all days in the period May 1 through September 30.

(6) The seasonal mean concentrations from step (5) are divided by the corresponding seasonal mean concentrations from the base period air quality model run. This step provides a Relative Response Factor (i.e., RRF) between the base period and control scenario for MDA1 and MDA8 in each model grid cell.

(7) Finally, the RRFs for the seasonal mean metrics from step (6) are then multiplied by the corresponding seasonal mean concentrations from the base period MDA1 and MDA8 fused surfaces to produce seasonal mean concentrations for MDA1 and MDA8 for the control scenario that are input to BenMAP-CE.

3.3 Application of ACE Approach for the Revised CSAPR Update

In this section we describe how we applied the ACE approach to generate spatial fields of seasonal ozone and annual $PM_{2.5}$ concentrations associated with the regulatory control alternatives (i.e., the rule and the less stringent and more stringent alternatives) in this rule RIA. The data for creating the Revised CSAPR Update spatial fields include EGU emissions for the 2021 and 2024 baseline and the regulatory control alternatives. The EGU emissions include OS NOx and annual NOx, SO2, and $PM_{2.5}$ for coal-fired and non-coal units in each state in the continental U.S. These EGU emissions are taken from the electricity sector analysis described in Chapter 4. In the case of the Revised CSAPR Update analysis, there are no impacts on SO_2 or $PM_{2.5}$ emissions in the regulatory control scenarios compared to the 2024 baseline.

To potentially calculate ozone-related benefits in 2021 and 2024 we used the ozone season EGU NOx emissions (tons) for the 2021 and 2024 baseline along with emissions for the rule, and each of the two other regulatory control alternatives. These emissions were applied using the ACE approach and source apportionment data to produce spatial fields of the May-September seasonal average MDA8 ozone and the April-October seasonal average MDA1 ozone concentrations as described in the previous section.

In 2021, the only control measures expected to be adopted for compliance in each of the regulatory control alternatives include optimization of existing SCRs and SNCRs beginning in May of 2021, and these measures will operate only during the ozone season. This is relevant because NOx reductions in the ozone season provide minimal $PM_{2.5}$ reductions since $PM_{2.5}$ nitrate concentrations, which result from conversion of NOx emissions to nitrate, are minimal during the warmer temperatures during the ozone season. Conversely, the conversion of nitrates to $PM_{2.5}$ is much greater in cooler (non-ozone season) months, and thus it would be considered worthwhile to estimate $PM_{2.5}$ benefits from NOx reductions in those months (Hand et al., 2012). In 2024, the presence of additional control measures that operate year-round and other changes in market conditions as a result of the rule lead to notable NOx reductions in the winter months.

To create spatial fields for $PM_{2.5}$ we pre-processed the 2024 coal and non-coal fired EGU emissions in order to obtain annual emissions of NOx, SO2, and directly emissions $PM_{2.5}$ in a manner that is appropriate for assessing the impacts on annual average $PM_{2.5}$ concentrations. This additional pre-processing was needed because the vast majority of the emissions reductions are expected to occur during the ozone season but, as noted above, $PM_{2.5}$ nitrate concentrations are lowest during that time of year. In this regard, simply treating the summer emissions reductions as if they were abated proportionately throughout the year would overstate the impacts of the emissions reductions on $PM_{2.5}$ and therefore overstate benefits associated with reducing exposure to $PM_{2.5}$. For those states in which there are NOx emissions reductions during the ozone season only, we reset the annual NOx emission in the regulatory alternative to be equivalent to the corresponding baseline emissions to avoid distributing the ozone season reductions across the entire year. That is, we assumed that there would be no impact on $PM_{2.5}$ nitrate concentrations of NOx reductions in the ozone season. For those states in which there are NOx emissions changes between the baseline and regulatory control alternative outside of the ozone season, we accounted for those reductions by "annualizing" the EGU emissions for the period outside the ozone season in the regulatory alternative as well as the corresponding baseline. This method essentially applies the change in NO_X tons outside the ozone season on a daily basis to changes in NOx emissions tons within the ozone season.[11] With this adjustment the impact of the regulatory control alternative on annual average $PM_{2.5}$ concentrations reflects the emissions reductions that will occur outside the ozone season when $PM_{2.5}$ nitrate concentrations are highest. The emissions of SO_2 and directly emitted $PM_{2.5}$ in 2024 for each of the regulatory alternatives do not change from the 2024 baseline. That is, the regulatory control alternatives analyzed in this RIA reduce emissions of NOx, but do not impact emissions of SO_2 and directly emitted $PM_{2.5}$.

3.4 Spatial Distribution of Air Quality Impacts

Below we present the estimated impacts on May-September MDA8 ozone[12] between the baseline and each of the regulatory control alternatives for 2021 and 2024 as well as the estimated impacts on annual mean $PM_{2.5}$ concentrations between the baseline and the regulatory control alternatives in 2024 (Figure 3-2 through Figure 3-10). The data shown in these figures are calculated as the baseline minus the regulatory control alternative concentrations (i.e., positive values indicate reductions in pollutant concentrations). The spatial patterns of the impacts of emissions reductions are a result of (1) the spatial distribution of EGU sources that are predicted to have changes in emissions and (2) the physical or chemical processing that the model simulates in the atmosphere.

[11] In all states the actual tons reduced in the ozone season is greater than or equal to the change outside the ozone season between the baseline and the regulatory alternatives.
[12] The estimated impacts on April-October 2021 and 2024 ozone for each scenario are not shown but are similar to May-September impacts available in Figure 12-20.

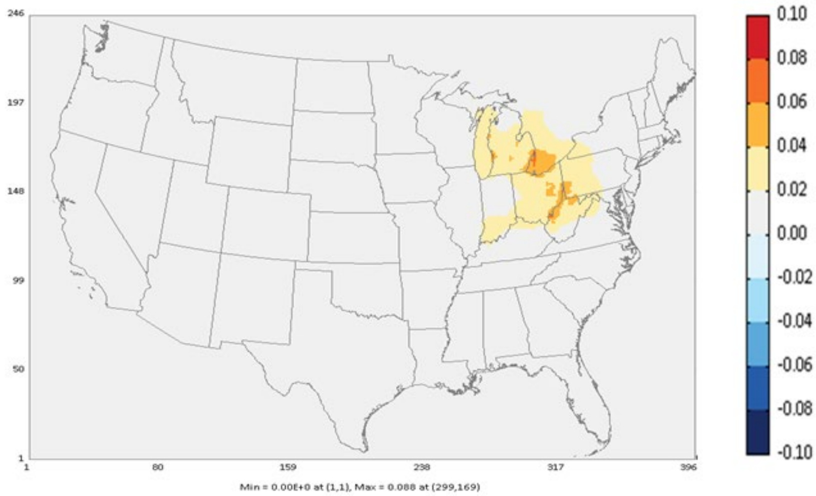

Figure 3-2. Map of change in May-September MDA8 ozone (ppb): 2021 baseline – less stringent regulatory alternative (scale: ± 0.10 ppb)

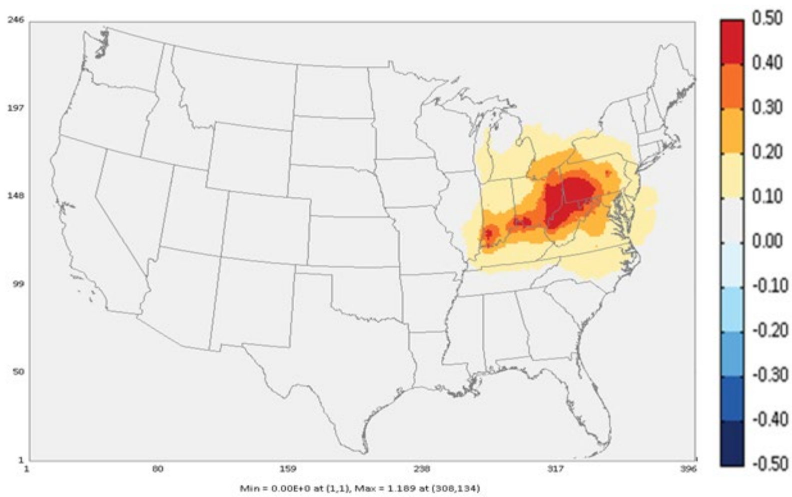

Figure 3-3. Map of change in May-September MDA8 ozone (ppb): 2021 baseline – rule (scale: ± 0.50 ppb)

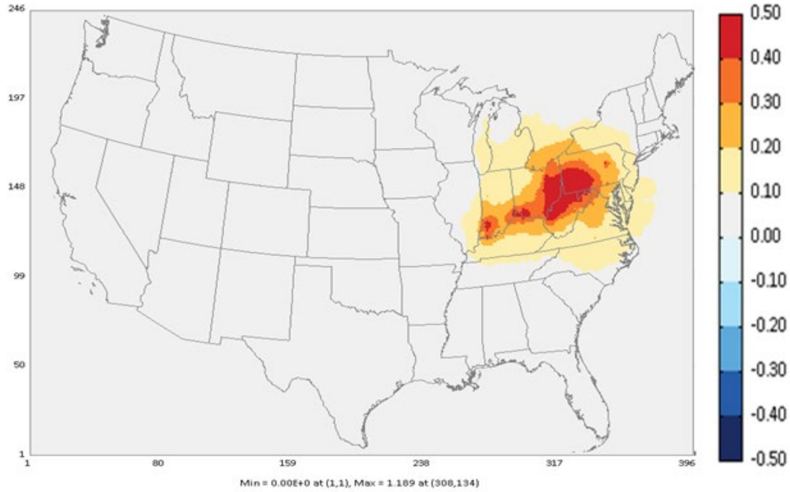

Figure 3-4. Map of change in May-September MDA8 ozone (ppb): 2021 baseline – more stringent regulatory alternative (scale: ± 0.50 ppb)

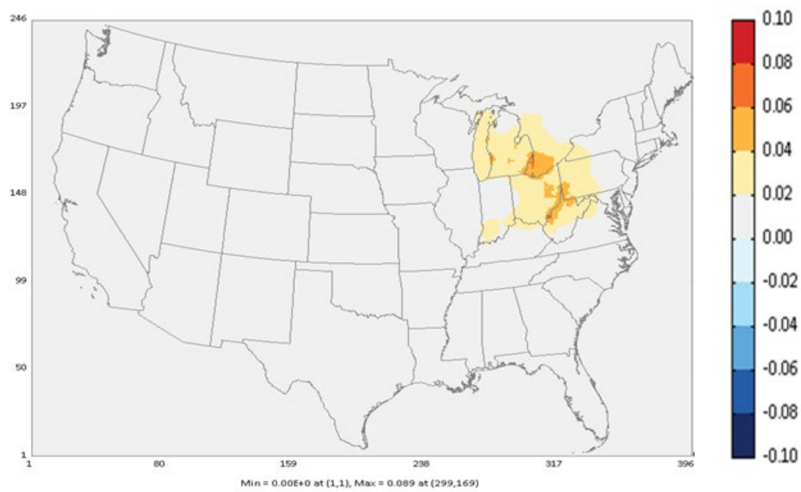

Figure 3-5. Map of change in May-September MDA8 ozone (ppb): 2024 baseline – less stringent regulatory alternative (scale: ± 0.10 ppb)

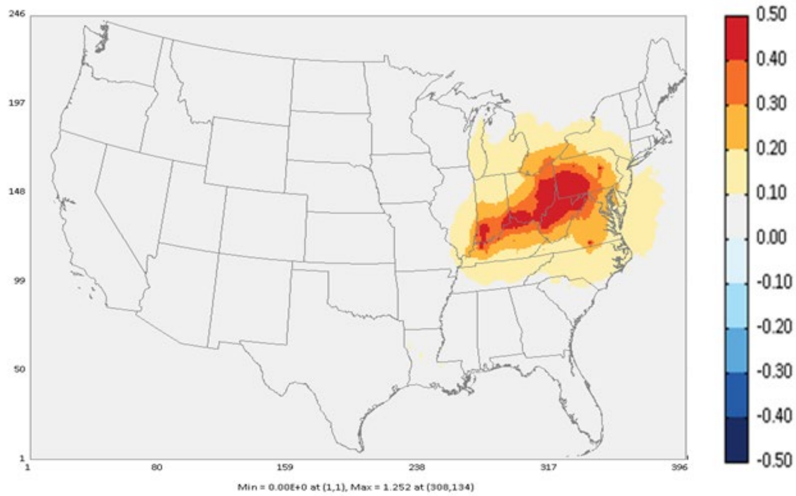

Figure 3-6. Map of change in May-September MDA8 ozone (ppb): 2024 baseline – rule (scale: + 0.50 ppb)

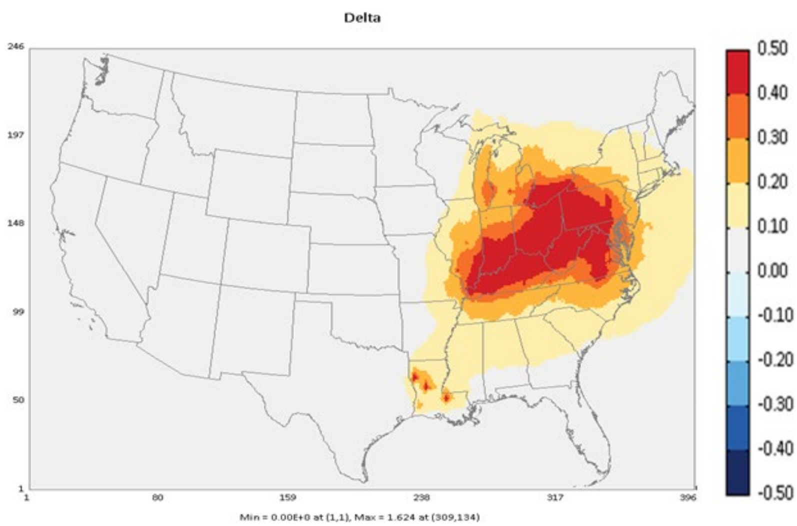

Figure 3-7. Map of change in May-September MDA8 ozone (ppb): 2024 baseline – more stringent regulatory alternative (scale: + 0.50 ppb)

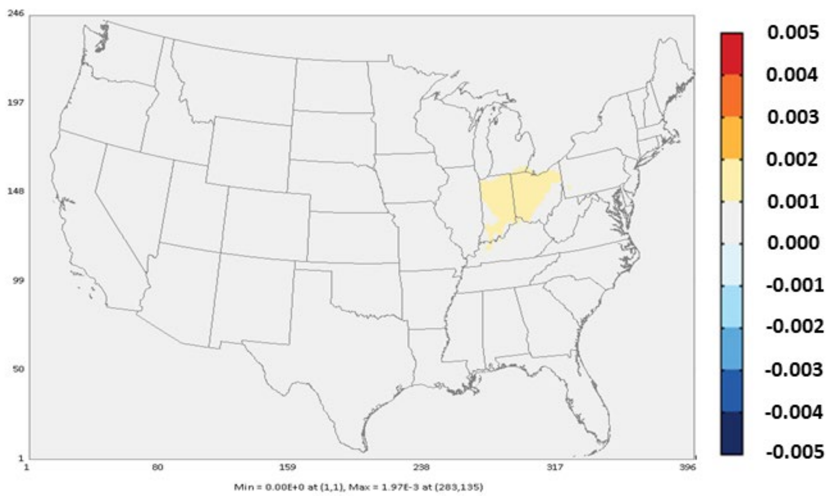

Figure 3-8. Map of change in annual mean $PM_{2.5}$ (µg/m^3): 2024 baseline – rule (scale: $\pm$ 0.005 µg/m^3)

3.5 Uncertainties and Limitations of ACE Approach

One limitation of the scaling methodology for creating $PM_{2.5}$ surfaces associated with the baseline and regulatory alternatives described above is that it treats air quality changes from the tagged sources as linear and additive. It therefore does not account for nonlinear atmospheric chemistry and does not account for interactions between emissions of different pollutants and between emissions from different tagged sources. This is consistent with how air quality estimations have been treated in past regulatory analyses (U.S. EPA 2012; 2019; 2020b). We note that air quality is calculated in the same manner for the baseline and the regulatory alternatives, so any uncertainty associated with these assumptions is carried through both sets of scenarios in the same manner and is thus not expected to impact the air quality differences between scenarios. In addition, emissions changes between baseline and the regulatory alternatives are relatively small compared to modeled 2023 emissions that form the basis of the ACE source apportionment approach. Previous studies have shown that air pollutant concentrations generally respond linearly to small emissions changes of up to 30 percent (Dunker et al., 2002; Cohan et al., 2005; Napelenok et al., 2006; Koo et al., 2007; Zavala et al., 2009; Cohan and Napelenok, 2011) and that linear scaling from source apportionment can do a reasonable job of representing impacts of 100 percent of emissions from individual sources (Baker and Kelly 2014). Therefore, while simplistic, it is reasonable to expect that the emissions concentration differences between the baseline and regulatory control alternatives can be adequately represented using this methodology and any uncertainty should be weighed against the speed in which this method may be used to account for spatial differences in the effect of EGU emissions on ozone and $PM_{2.5}$ concentrations.

A second limitation is that the source apportionment $PM_{2.5}$ contributions represent the spatial and temporal distribution of the emissions from each source tag as they occur in the 2023 modeled case. Thus, the contribution modeling results do not allow us to represent any changes to "within tag" spatial distributions. As a result, the method does not account for any changes of spatial patterns that would result from changes in the relative magnitude of sources within a source tag in the scenarios investigated here. As described above, the EGU tags are generally by state and by two EGU types; one for coal-fired units and one for non-coal units.

In addition, the 2023 CAMx-modeled concentrations themselves have some uncertainty. While all models have some level of inherent uncertainty in their formulation and inputs, the base-year 2011 model outputs have been evaluated elsewhere against ambient measurements (U.S. EPA 2017; 2019) and have been shown to adequately reproduce spatially and temporally varying ozone and $PM_{2.5}$ concentrations.

The regulatory alternatives lead to decreased concentrations of ozone and $PM_{2.5}$, the extent to which varies by location, relative to the baseline. However, the analysis does not account for how interaction with NAAQS compliance would affect the benefits and costs of the regulatory alternatives, which introduces uncertainty in the benefits and costs of the alternatives. To the extent the Revised CSAPR Update will decrease NO_X and consequentially ozone and $PM_{2.5}$, these changes may affect compliance with existing NAAQS standards and subsequently affect the actual benefits and costs of the rule. In areas not projected to attain the 2015 ozone NAAQS without further emissions reductions from the baseline, states may be able avoid applying some emissions control measures to reduce emissions from local sources as a result of this rule. If compliance behavior with the 2015 ozone NAAQS were accounted for in the baseline in this RIA there may be additional benefits from reduced compliance costs, while the level and spatial pattern of changes in ozone and $PM_{2.5}$ concentrations, and their associated health and ecological benefits, would differ.

Similarly, the regulatory alternatives may project decreases in ozone and $PM_{2.5}$ concentrations in areas attaining the NAAQS in the baseline. In practice, these potential changes in concentrations may influence NAAQS compliance plans in these areas, which in turn would further influence concentrations and the cost of complying with the NAAQS. However, such behavior will be mitigated by NAAQS requirements such as Prevention of Significant Deterioration (PSD) requirements. This RIA does not account for how interaction with NAAQS compliance would affect the benefits and costs of the regulatory alternatives.

3.6 References

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APPENDIX 3A: METHODOLOGY FOR DEVELOPING AIR QUALITY SURFACES

In this appendix we describe the air quality modeling platform and methodology that was leveraged to prepare the air quality surfaces that could inform the calculation of health benefits of the Revised CSAPR Update final rule. The modeling and methodology described here were developed to support the Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (U.S. EPA 2019), also referred to the Affordable Clean Energy (ACE) rule. The foundational data in the ACE approach included the 2023 ACE baseline EGU emissions and the 2023 ACE EGU air quality contribution data described below. To generate spatial fields for alternative EGU scenarios, such as the scenarios analyzed for the Revised CSAPR Update, the user provides as input EGU emissions for coal-fired and non-coal units for each state, separately. Ozone season EGU NOx emissions (tons) are used to prepare spatial fields of the May-September seasonal average MDA8 ozone and the April-October seasonal average MDA1 ozone concentrations and annual total EGU emissions of NOx, SO2 and $PM_{2.5}$ are used to prepare spatial fields of annual $PM_{2.5}$ concentrations. Emissions scaling ratios, described below, that are used to prepare the air quality spatial fields.

3A.1 Air Quality Modeling Platform for the ACE Rule

As part of the ACE assessment we used existing air quality modeling for 2011 and 2023 to estimate $PM_{2.5}$ and ozone concentrations in the future years analyzed for the ACE final rule. The modeling platform consists of several components including the air quality model, meteorology, estimates of international transport, and base year and future year emissions from anthropogenic and natural sources. An overview of each of these platform comments is provided in the subsections below.

3A.1.1 Air Quality Model, Meteorology and Boundary Conditions

We used the Comprehensive Air Quality Model with Extensions (CAMx version 6.40) with the Carbon Bond chemical mechanism CB6r4 for modeling base year and future year ozone and $PM_{2.5}$ concentrations (Ramboll, 2016). CAMx is a three-dimensional grid-based photochemical air quality model designed to simulate the formation and fate of oxidant precursors, primary and secondary particulate matter concentrations, and deposition over national, regional and urban spatial scales. Consideration of the different processes (e.g., transport and deposition) that affect primary (directly emitted) and secondary (formed by atmospheric processes) pollutants in different locations is fundamental to understanding and assessing the effects of emissions on air quality concentrations.

The geographic extent of the modeling domain covers the 48 contiguous states along with the southern portions of Canada and the northern portions of Mexico as shown in Figure1. This modeling domain contains 25 vertical layers with a top at about 17,550 meters[1] and horizontal grid resolution of 12 km x 12 km. The model simulations produce hourly air quality concentrations for each 12-km grid cell across the modeling domain.

Figure 3A-1. Air Quality Modeling Domain

The 2011 meteorological data for air quality modeling were derived from running Version 3.4 of the Weather Research Forecasting Model (WRF) (Skamarock, et al., 2008). The meteorological outputs from WRF include hourly-varying horizontal wind components (i.e., speed and direction), temperature, moisture, vertical diffusion rates, and rainfall rates for each vertical layer in each grid cell. The 2011 meteorology was used for both the 2011 base year and 2023 future year air quality modeling. Details of the annual 2011 meteorological model simulation and evaluation are provided in a separate technical support document (US EPA,

[1] Since the model top is defined based on atmospheric pressure, the actual height of the model top varies somewhat with time and location.

2014a) which can be obtained at:
http://www.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf

The lateral boundary and initial species condition concentrations are provided by a three-dimensional global atmospheric chemistry model, GEOS-Chem (Yantosca, 2004) standard version 8-03-02 with 8-02-01 chemistry. The global GEOS-Chem model simulates atmospheric chemical and physical processes driven by assimilated meteorological observations from the NASA's Goddard Earth Observing System (GEOS-5).[2] GEOS-Chem was run for 2011 with a grid resolution of 2.0 degrees x 2.5 degrees (latitude-longitude). The predictions were used to provide one-way dynamic boundary condition concentrations at three-hour intervals and an initial concentration field for the CAMx simulations. The 2011 boundary concentrations from GEOS-Chem were used for both the 2011 and 2023 model simulations. The procedures for translating GEOS-Chem predictions to initial and boundary concentrations are described elsewhere (Henderson, 2014). More information about the GEOS-Chem model and other applications using this tool is available at: http://www-as.harvard.edu/chemistry/trop/geos.

3A.1.2 2011 and 2023 Emissions

The purpose of the 2011 base year modeling is to represent the year 2011 in a manner consistent with the methods used in the 2023 future year base case. The emissions data in this platform are primarily based on the 2011 National Emissions Inventory (NEI) v2 for point sources, nonpoint sources, commercial marine vessels, nonroad mobile sources and fires.[3] The onroad mobile source emissions are similar to those in the 2011 NEIv2, but were generated using the 2014a version of the Motor Vehicle Emissions Simulator (MOVES2014a) (http://www.epa.gov/otaq/models/moves/). The 2011 and 2023 emission inventories incorporate revisions implemented based on comments received on the Notice of Data Availability (NODA)

[2] Additional information is available at:
http://gmao.gsfc.nasa.gov/GEOS/ and http://wiki.seas.harvard.edu/geos-chem/index.php/GEOS-5).

[3] Note that EPA used a more recent 2016-based emissions platform for air quality modeling to provide the foundational data needed to identify receptors and interstate contributions for the rule. The 2016-based mobile emissions platform data were based on MOVES2014b. The 2016-based emissions platform is described in the Emissions Modeling Technical Support Document available at: https://www.epa.gov/air-emissions-modeling/2016v1-platform. Although the modeling data in the ACE approach are based on the 2011 platform (and the 2011-based platform mobile emissions data were developed using MOVES2014a), the state-EGU contribution modeling data, as described in this appendix, provide a means to develop spatial fields of air quality for the 2021 and 2025 baseline and the rule and alternative control scenarios analyzed in this RIA.

issued in January 2017 “Preliminary Interstate Ozone Transport Modeling Data for the 2015 Ozone National Ambient Air Quality Standard” (82 FR 1733), along with revisions made from prior notices and rulemakings on earlier versions of the 2011 platform. The preparation of the emission inventories for air quality modeling is described in the Technical Support Document (TSD) Additional Updates to Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform for the Year 2023 (US EPA, 2017a). Electronic copies of the emission inventories and ancillary data used to produce the emissions inputs to the air quality model are available from the 2011en and 2023 en section of the EPA Air Emissions Modeling website for the 2011v6.3 emissions modeling platform: https://www.epa.gov/air-emissions-modeling/2011-version-63-platform.

The emission inventories for the 2023 ACE future year were developed using projection methods that are specific to the type of emission source. Future emissions are projected from the 2011 current year either by running models to estimate future year emissions from specific types of emission sources (e.g., EGUs, and onroad and nonroad mobile sources)[4], or for other types of sources by adjusting the base year emissions according to the best estimate of changes expected to occur in the intervening years. For sectors which depend strongly on meteorology (such as biogenic and fires), the same emissions are used in the base and future years to be consistent with the 2011 meteorology used when modeling 2023. For the remaining sectors, rules and specific legal obligations that go into effect in the intervening years, along with changes in activity for the sector, are considered when possible. Emissions inventories for neighboring countries used in our modeling are included in this platform, specifically 2011 and 2023 emissions inventories for Mexico, and 2013 and 2025 emissions inventories for Canada. The meteorological data used to create and temporalize emissions for the future year cases is held constant and represents the year 2011. The same ancillary data files[5] are used to prepare the future year emissions inventories for air quality modeling as were used to prepare the 2011 base year inventories with the exception of chemical speciation profiles for mobile sources and temporal profiles for EGUs.

[4] California provided emissions for the modeling platform. As such, onroad mobile source emissions for California were consistent with the emissions provided by the state.
[5] Ancillary data files include temporal, spatial, and VOC/$PM_{2.5}$ chemical speciation surrogates.

The projected EGU emissions reflect the emissions reductions expected due to the Final Mercury and Air Toxics (MATS) rule announced on December 21, 2011, the Cross-State Air Pollution Rule (CSAPR) issued July 6, 2011, and the CSAPR Update issued October 26, 2016. The 2023 EGU projected inventory was developed using an engineering analysis approach. EPA started with 2016 reported, seasonal, historical emissions for each unit. The emissions data for NO_X and SO_2 for units that report data under either the Acid Rain Program (ARP) and/or the CSAPR were aggregated to the summer/ozone season period (May-September) and winter/non-ozone period (January-April and October-December).[6] Adjustments to 2016 levels were made to account for retirements, coal to gas conversion, retrofits, state-of-the-art combustion controls, along with other unit-specific adjustments. Details and these adjustments, and information about handling for units not reporting under Part 75 and pollutants other than NO_X and SO_2 are described in the emissions modeling TSD (US EPA, 2017a).

The 2023 non-EGU stationary source emissions inventory includes impacts from enforceable national rules and programs including the Reciprocating Internal Combustion Engines (RICE) and cement manufacturing National Emissions Standards for Hazardous Air Pollutants (NESHAPs) and Boiler Maximum Achievable Control Technology (MACT) reconsideration reductions. Projection factors and percent reductions for non-EGU point sources reflect comments received by EPA in response to the January 2017 NODA, along with emissions reductions due to national and local rules, control programs, plant closures, consent decrees and settlements. Growth and control factors provided by states and by regional organizations on behalf of states were applied. Reductions to criteria air pollutant (CAP) emissions from stationary engines resulting from the Reciprocating Internal Combustion Engines (RICE) National Emission Standard for Hazardous Air Pollutants (NESHAP) are included. Reductions due to the New Source Performance Standards (NSPS) VOC controls for oil and gas sources, and the NSPS for process heaters, internal combustion engines, and natural gas turbines were also included.

[6] EPA notes that historical state-level ozone season EGU NO_X emission rates are publicly available and quality assured data. They are monitored using continuous emissions monitors (CEMs) data and are reported to EPA directly by power sector sources. They are reported under Part 75 of the CAA.

For point and nonpoint oil and gas sources, state projection factors were generated using state-specific historical oil and gas production data available from EIA for 2011 to 2015 and information from regional factors based AEO 2017 to project the emission to the year 2023. Emission reductions of stationary engines CAP reductions (RICE NESHAP) and controls from New Source Performance Standards (NSPS) are reflected for select source categories. Mid-Atlantic Regional Air Management Association (MARAMA) factors for the year 2023 were used where applicable. Projection factors for other nonpoint sources such as stationary source fuel combustion, industrial processes, solvent utilization, and waste disposal, reflect emissions reductions due to control programs along with comments on the growth and control of these sources as a result of the January 2017 NODA and information gathered from prior rulemakings and outreach to states on emission inventories.

The MOVES2014a-based 2023 onroad mobile source emissions account for changes in activity data and the impact of on-the-books national rules including: the Tier 3 Vehicle Emission and Fuel Standards Program, the 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards (LD GHG), the Renewable Fuel Standard (RFS2), the Mobile Source Air Toxics Rule, the Light Duty Green House Gas/Corporate Average Fuel Efficiency (CAFE) standards for 2012-2016, the Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles, the Light-Duty Vehicle Tier 2 Rule, and the Heavy-Duty Diesel Rule. The MOVES-based emissions also include state rules related to the adoption of LEV standards, inspection and maintenance programs, Stage II refueling controls, and local fuel restrictions.

The nonroad mobile 2023 emissions, including railroads and commercial marine vessel emissions also include all national control programs. These control programs include the Clean Air Nonroad Diesel Rule – Tier 4, the Nonroad Spark Ignition rules, and the Locomotive-Marine Engine rule. For ocean-going vessels (Class 3 marine), the emissions data reflect the 2005 voluntary Vessel Speed Reduction (VSR) within 20 nautical miles, the 2007 and 2008 auxiliary engine rules, the 40 nautical mile VSR program, the 2009 Low Sulfur Fuel regulation, the 2009-2018 cold ironing regulation, the use of 1 percent sulfur fuel in the Emissions Control Area (ECA) zone, the 2012-2015 Tier 2 NO_X controls, the 2016 0.1 percent sulfur fuel regulation in ECA zone, and the 2016 International Marine Organization (IMO) Tier 3 NO_X controls. Non-

U.S. and U.S. category 3 commercial marine emissions were projected to 2025 using consistent methods that incorporated controls based on ECA and IMO global NO_X and SO_2 controls.

3A.1.3 2011 Model Evaluation for Ozone and $PM_{2.5}$

An operational model performance evaluation was conducted to examine the ability of the 2011 base year model run to simulate the corresponding 2011 measured ozone and $PM_{2.5}$ concentrations. This evaluation focused on four statistical metrics comparing model predictions to the corresponding observations. The performance statistics include mean bias, mean error, normalized mean bias, and normalized mean error. Mean bias (MB) is the sum of the difference (predicted – observed) divided by the total number of replicates (*n*). Mean bias is given in units of ppb and is defined as:

$$\mathrm{MB} = \frac{1}{n}\sum_1^n (P - O) \qquad \text{(Eq-1)}$$

Where:

- P is the model-predicted concentration;
- O is the observed concentrations; and
- n is the total number of observations

Mean error (ME) calculates the sum of the absolute value of the difference (predicted - observed) divided by the total number of replicates (*n*). Mean error is given in units of ppb and is defined as:

$$\mathrm{ME} = \frac{1}{n}\sum_1^n |P - O| \qquad \text{(Eq-2)}$$

Normalized mean bias (NMB) is the sum of the difference (predicted - observed) over the sum of observed values. NMB is a useful model performance indicator because it avoids over inflating the observed range of values, especially at low concentrations. Normalized mean bias is given in percentage units and is defined as:

$$\mathrm{NMB} = \frac{\sum_1^n (P-O)}{\sum_1^n (O)} * 100 \qquad \text{(Eq-3)}$$

Normalized mean error (NME) is the sum of the absolute value of the difference (predicted - observed) divided by the sum of observed values. Normalized mean error is given in percentage units and is defined as:

$$NME = \frac{\sum_1^n |P-O|}{\sum_1^n (O)} * 100 \qquad \text{(Eq-4)}$$

For $PM_{2.5}$, performance statistics were calculated for modeled and observed 24-hour average concentrations paired by day and location for the entire year. Performance statistics were calculated for monitoring data in the Chemical Speciation Network (CSN)[7] and, separately, for monitoring data in the Interagency Monitoring of Protected Visual Environments (IMPROVE)[8] network. For ozone, performance statistics were calculated for modeled concentrations with observed 8-hour daily maximum (MDA8) ozone concentrations at or above 60 ppb[9] over the period May through September for monitoring sites in the Air Quality System (AQS)[10,11] network. For both $PM_{2.5}$ and ozone, the modeled and predicted pairs of data were aggregated by 9 regions across the U.S. for the calculation of model performance statistics. These 9 regions are shown in Figure 3A-2.[12]

[7] Additional information on the measurements made at CSN monitoring sites can be found at the following web link: https://www.epa.gov/amtic/chemical-speciation-network-csn.
[8] Additional information on the measurements made at IMPROVE monitoring sites can be found at the following web link: https://www3.epa.gov/ttnamti1/visdata.html.
[9] Performance statistics are calculated for days with measured values at or above 60 ppb in order to focus the evaluation on days with high rather than low concentrations.
[10] Additional information on the measurements made at AQS monitoring sites can be found at the following web link: https://www.epa.gov/aqs.
[11] Note that the AQS data base also includes measurements made at monitoring sites in the Clean Air Status and Trends Network (CASTNet).
[12] Source: http://www.ncdc.noaa.gov/monitoring-references/maps/us-climate-regions.php#references.

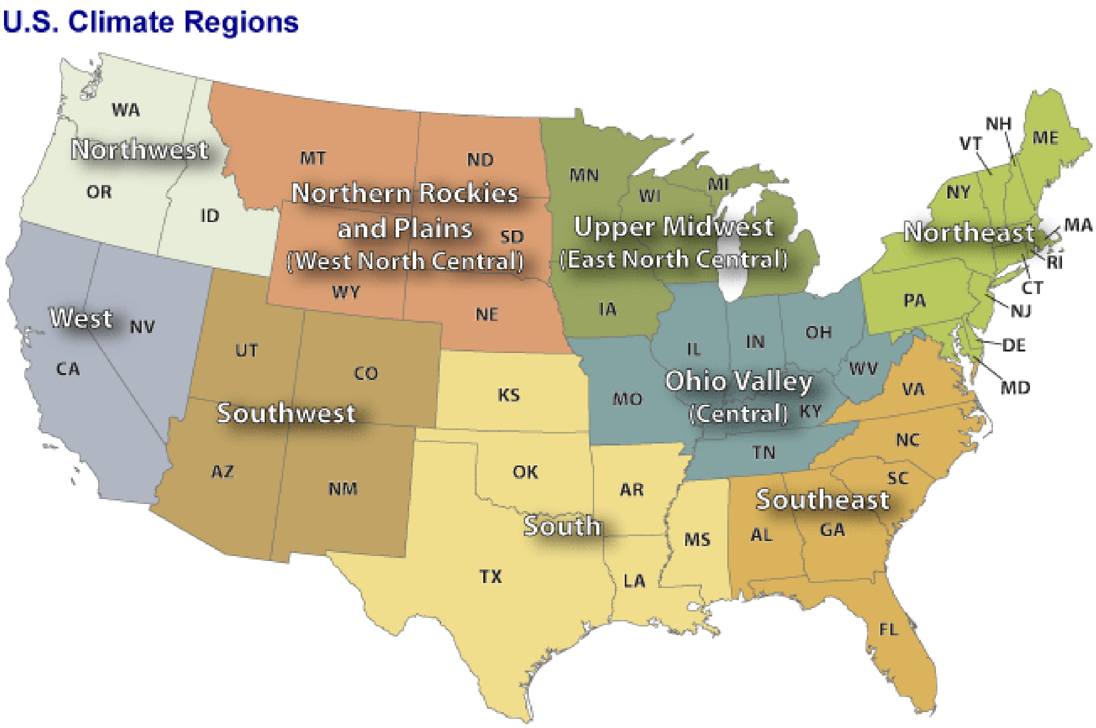

Figure 3A-2. NOAA Climate Regions

Model performance statistics for $PM_{2.5}$ for each region are provided in Table 3A.1. These data indicate that over the year as a whole, $PM_{2.5}$ is over predicted in the Northeast, Ohio Valley, Upper Midwest, Southeast, and Northwest regions and under predicted in the South and Southwest regions. Normalized mean bias is within ±30 percent in all regions except the Northwest which has somewhat larger model over-predictions. Model performance for $PM_{2.5}$ for the 2011 modeling platform is similar to the model performance results for other contemporary, state of the science photochemical model applications (Simon et al., 2012). Additional details on $PM_{2.5}$ model performance for the 2011 base year model run can be found in the Technical Support Document for EPA's preliminary regional haze modeling (US EPA, 2017b).

Table 3A.1. Model Performance Statistics by Region for $PM_{2.5}$

Region	Network	No. of Obs	MB ($\mu g/m^3$)	ME ($\mu g/m^3$)	NMB (%)	NME (%)
Northeast	IMPROVE	1577	0.87	2.21	17.70	44.90
	CSN	2788	0.97	4.04	9.70	40.40
Ohio Valley	IMPROVE	680	0.10	2.96	1.20	35.50
	CSN	2475	0.13	3.85	1.10	32.80
Upper Midwest	IMPROVE	700	0.83	2.37	14.20	40.40
	CSN	1343	1.37	3.66	13.60	36.30
Southeast	IMPROVE	1172	0.52	3.54	6.30	43.20
	CSN	1813	0.19	3.92	1.70	34.20
South	IMPROVE	933	-0.47	2.69	-6.50	37.40
	CSN	962	-0.08	4.48	-0.75	39.50
Southwest	IMPROVE	3695	-1.12	1.86	-28.00	46.30
	CSN	746	-0.08	3.93	-1.00	47.10
N. Rockies/	IMPROVE	1952	0.07	1.39	2.40	44.90
Plains	CSN	275	-2.07	4.18	-21.80	43.90
Northwest	IMPROVE	1901	1.19	2.28	43.20	82.90
	CSN	668	5.77	7.25	69.90	87.90
West	IMPROVE	1782	-1.08	2.08	-25.30	48.50
	CSN	936	-2.92	5.08	-23.10	40.30

Model performance statistics for May through September MDA8 ozone concentrations for each region are provided in Table 3A.2. Overall, measured ozone is under predicted in most regions, except for the Northeast and Southeast where over prediction is found. Normalized mean bias is within ±15 percent in all regions. Model performance for ozone for the 2011 modeling platform is similar to the model performance results for other contemporary, state of the science photochemical model applications (Simon et al., 2012). Additional details on ozone model performance for the 2011 base year model run can be found in the Air Quality Technical Support Document for EPA's preliminary interstate ozone transport modeling for the 2015 ozone National Ambient Air Quality Standard (US EPA, 2017c).

Table 3A.2. Model Performance Statistics by Region for Ozone on Days Above 60 ppb (May-Sep)

Region	No. of Obs	MB (ppb)	ME (ppb)	NMB (%)	NME (%)
Northeast	4085	1.20	7.30	1.80	10.70
Ohio Valley	6325	-0.60	7.50	-0.90	11.10
Upper Midwest	1162	-4.00	7.60	-5.90	11.10
Southeast	4840	2.30	6.80	3.40	10.20
South	5694	-5.30	8.40	-7.60	12.20
Southwest	6033	-6.20	8.50	-9.40	12.90
N. Rockies/Plains	380	-7.20	8.40	-11.40	13.40
Northwest	79	-5.60	9.00	-8.70	14.00
West	8655	-8.60	10.30	-12.20	14.50

Thus, the model performance results demonstrate the scientific credibility of our 2011 modeling platform for predicting $PM_{2.5}$ and ozone concentrations. These results provide confidence in the ability of the modeling platform to provide a reasonable projection of expected future year ozone concentrations and contributions.

3A.2 Source Apportionment Tags

CAMx source apportionment modeling was used to track ozone and $PM_{2.5}$ component species impacts from pre-defined groups of emissions sources (source tags). Separate tags were created for state-level EGUs split by fuel type (coal units versus non-coal units[13]). For some states with low EGU emissions, EGUs are grouped with nearby states that also have low EGU emissions. In addition, there are no coal EGUs operating in the 2023 emissions case for the following states: Idaho, Oregon, and Washington. Therefore, there is no coal EGU tag for those states. Similarly, there were no EGUs (coal or non-coal) in Washington D.C. in the 2023 emissions scenario, so there were no EGU tags for Washington D.C. There were also several domain-wide tags for sources other than EGUs. Table 3A.3 provides a full list of the emissions group tags that were tracked in the source apportionment modeling.

[13] For the purposes of this analysis non-coal fuels include emissions from natural gas, oil, biomass, and waste coal-fired EGUs.

Table 3A.3. Source Apportionment Tags

Coal-fired EGU tags	Non-coal EGU tags	Domain-wide tags
• Alabama • Arizona • Arkansas • California • Colorado • Connecticut + Rhode Island • Delaware + New Jersey • Florida • Georgia • Illinois • Indiana • Iowa • Kansas • Kentucky • Louisiana • Maine + Mass. + New Hamp. + Vermont • Maryland • Michigan • Minnesota • Mississippi • Missouri • Montana • Nebraska • Nevada • New Mexico • New York • North Carolina • North Dakota + South Dakota • Ohio • Oklahoma • Pennsylvania • South Carolina • Tennessee • Texas • Utah • Virginia • West Virginia • Wisconsin • Wyoming • Tribal Data*	• Alabama • Arizona • Arkansas • California • Colorado • Connecticut + Rhode Island • Delaware + New Jersey • Florida • Georgia • Idaho + Oregon + Washington • Illinois • Indiana • Iowa • Kansas • Kentucky • Louisiana • Maine + Mass. + New Hamp. + Vermont • Maryland • Michigan • Minnesota • Mississippi • Missouri • Montana • Nebraska • Nevada • New Mexico • New York • North Carolina • North Dakota + South Dakota • Ohio • Oklahoma • Pennsylvania • South Carolina • Tennessee • Texas • Utah • Virginia • West Virginia • Wisconsin • Wyoming • Tribal Data[14]	• EGU retirements through 2025 • EGU retirements 2026-2030 • All U.S. anthropogenic emissions from source sectors other than EGUs • International within-domain emissions (sources occurring in Canada, Mexico, and from offshore marine vessels and drilling platforms) • Fires (wildfires and prescribed fires) • Biogenic sources • Boundary conditions

[14] EGUs operating on tribal lands were tracked together in a single tag. There are EGUs on tribal land in the following states: Utah (coal), New Mexico (coal), Arizona (coal and non-coal), Idaho (non-coal). EGU emissions occurring on tribal lands were not included in the state-level EGU source tags.

The contributions represent the spatial and temporal distribution of the emissions within each source tag. Thus, the contribution modeling results do not allow us to represent any changes to any “within tag” spatial distributions. For example, the location of coal-fired EGUs in Michigan are held in place based on locations in the 2023 emissions. Additionally, the relative magnitude of sources within a source tag do not change from what was modeled with the 2023 emissions inventory.

3A.3 Applying Source Apportionment Contributions to Create Air Quality Fields

We created air quality surfaces for the ACE future year baseline and illustrative policy scenarios by scaling the EGU sector tagged contributions from the 2023 modeling based on relative changes in EGU emissions associated with each tagged category between the 2023 emissions case and the ACE scenarios. Below, we provide equations used to apply these scaling ratios along with tables of the ratios.

3A.3.2 Scaling Ratio Applied to Source Apportionment Tags

Scaling ratios for $PM_{2.5}$ components that are emitted directly from the source (OA, EC, crustal) were based on relative changes in annual primary $PM_{2.5}$ emissions between the 2023 emissions case and the ACE baseline and the illustrative policy scenario. Scaling ratios for components that are formed through chemical reactions in the atmosphere were created as follows: scaling ratios for sulfate were based on relative changes in annual SO_2 emissions; scaling ratios for nitrate were based on relative changes annual NO_X emissions; and scaling ratios for ozone formed in NO_X-limited regimes[15] (“O3N”) were based on relative changes in ozone season (May-September) NO_X emissions. The scaling ratios that were determined based on emissions provided for each scenario.

Scaling ratios were applied to create air quality surfaces for ozone using equation (9):

[15] The CAMx model internally determines whether the ozone formation regime is NO_X-limited or VOC-limited depending on predicted ratios of indicator chemical species.

$$Ozone_{m,g,d,i,y} = C_{m,g,d,BC} + C_{m,g,d,int} + C_{m,g,d,bio} + C_{m,g,d,fires} + C_{m,g,d,USanthro} + C_{m,g,d,y,EGUret} + \sum_{t=1}^{T} C_{VOC,m,g,d,t} + \sum_{t=1}^{T} C_{NOx,m,g,d,t} S_{t,i,y} \quad \text{(Eq-9)}$$

where:

- $Ozone_{m,g,d,i,y}$ is the estimated ozone for metric, "m" (MDA8 or MDA1), grid-cell, "g", day, "d", scenario, "i", and year, "y";
- $C_{m,g,d,BC}$ is the total ozone contribution from the modeled boundary inflow; $C_{m,g,d,int}$ is the total ozone contribution from international emissions within the model domain;
- $C_{m,g,d,bio}$ is the total ozone contribution from biogenic emissions;
- $C_{m,g,d,fires}$ is the total ozone contribution from fires;
- $C_{m,g,d,USanthro}$ is the total ozone contribution from U.S. anthropogenic sources other than EGUs;
- $C_{m,g,d,y,EGUret}$ is the total ozone contribution from retiring EGUs after year, "y" (this term is equal to 0 in 2030 and 2035);
- $C_{VOC,m,g,d,t}$ is the ozone contribution from EGU emissions of VOCs from tag, "t";
- $C_{NOx,m,g,d,t}$ is the ozone contribution from EGU emissions of NO_X from tag, "t"; and
- $S_{t,i,y}$ is the ozone scaling ratio for tag, "t", scenario, "i", and year, "y".

Scaling ratios were applied to create air quality surfaces for $PM_{2.5}$ species using equation (10) (for sulfate, nitrate, EC or crustal material) or using equation (11) (for OA):

$$PM_{s,g,d,i,y} = C_{s,g,d,BC} + C_{s,g,d,int} + C_{s,g,d,bio} + C_{s,g,d,fires} + C_{s,g,d,USanthro} + C_{s,g,d,y,EGUret} + \sum_{t=1}^{T} C_{s,g,d,t} S_{s,t,i,y} \quad \text{(Eq-10)}$$

$$OA_{g,d,i,y} = C_{POA,g,d,BC} + C_{POA,g,d,int} + C_{POA,g,d,bio} + C_{POA,g,d,fires} + C_{POA,g,d,USanthro} + C_{POA,g,d,y,EGUret} + SOA_{g,d} + \sum_{t=1}^{T} C_{POA,g,d,t} S_{pri,t,i,y} \quad \text{(Eq-11)}$$

where:

- $PM_{s,g,d,i,y}$ is the estimated concentration for species, "s" (sulfate, nitrate, EC, or crustal material), grid-cell, "g", day, "d", scenario, "i", and year, "y";
- $C_{s,g,d,BC}$ is the species contribution from the modeled boundary inflow;
- $C_{s,g,d,int}$ is the species contribution from international emissions within the model domain;
- $C_{s,g,d,bio}$ is the species contribution from biogenic emissions;
- $C_{s,g,d,fires}$ is the species contribution from fires;
- $C_{s,g,d,USanthro}$ is the species contribution from U.S. anthropogenic sources other than EGUs;
- $C_{s,g,d,y,EGUret}$ is the species contribution from retiring EGUs after year, "y" (this term is equal to 0 in 2030 and 2035);
- $C_{s,g,d,t}$ is the species contribution from EGU emissions from tag, "t"; and
- $S_{s,t,i,y}$ is the scaling ratio for species, "s", tag, "t", scenario, "i", and year, "y".

Similarly, for Equation (11):

- $OA_{g,d,i,y}$ is the estimated OA concentration for grid-cell, "g", day, "d", scenario, "i", and year, "y";
- Each of the contribution terms refers to the contribution to primary OA (POA); and
- $SOA_{g,d}$ represents the modeled secondary organic aerosol concentration for gird-cell, "g", and day, "d", which does not change among scenarios

3A.4 Creating Fused Fields Based on Observations and Model Surfaces

In this section we describe steps taken to estimate $PM_{2.5}$ and ozone gridded surfaces associated with the baseline and the illustrative policy scenario for every year. For $PM_{2.5}$, (daily gridded $PM_{2.5}$ species were processed into annual average surfaces which combine observed values with model predictions using the enhanced Veronoi Neighbor Average (eVNA) method (Gold et al., 1997; US EPA, 2007; Ding et al., 2015). These steps were performed using EPA's software package, Software for the Modeled Attainment Test – Community Edition (SMAT-CE)[16] and have been previously documented both in the user's guide for the predecessor software (Abt, 2014) and in EPA's modeling guidance document (U.S. EPA, 2014b). First, we create a 2011 eVNA surface for each PM component species. To create the 2011 eVNA surface, SMAT-CE first calculates quarterly average values (January-March; April-June; July-September; October-December) for each $PM_{2.5}$ component species at each monitoring site with available measured data. For this calculation we used 3 years of monitoring data (2010-2012)[17]. SMAT-CE then creates an interpolated field of the quarterly-average observed data for each $PM_{2.5}$ component species using inverse distance squared weighting resulting in a separate 3-year average interpolated observed field for each $PM_{2.5}$ species and each quarter. The interpolated observed fields are then adjusted to match the spatial gradients from the modeled data. These two steps can be calculated using Equation (12):

[16] Software download and documentation available at https://www.epa.gov/scram/photochemical-modeling-tools.
[17] Three years of ambient data is used to provide a more representative picture of air pollution concentrations.

$$eVNA_{g,s,q,2011} = \sum Weight_x Monitor_{x,s,q,2010-2012} \frac{Model_{g,s,q,2011}}{Model_{x,s,q,2011}} \quad \text{(Eq-12)}$$

Where:

- $eVNA_{g,s,q,current}$ is the gradient adjusted quarterly-average eVNA value at grid-cell, g, for PM component species, s, during quarter, q for the year 2011;
- $Weight_x$ is the inverse distance weight for monitor x at the location of grid-cell, g;
- $Monitor_{x,s,q,2010-2012}$ is the 3-year (2010-2012) average of the quarterly monitored concentration for species, s, at monitor, x, during quarter, q;
- $Model_{g,s,q,2011}$ is the 2011 modeled quarterly-average concentrations of species, s, at grid cell, g, during quarter, q; and
- $Model_{x,s,q,2011}$ is the 2011 modeled quarterly-average concentration of species, s, at the location of monitor, x, during quarter q.

The 2011 eVNA field serves as the starting point for future-year projections. To create a gridded future-year eVNA surfaces for the baseline and ACE illustrative policy, we take the ratio of the modeled future year[18] quarterly average concentration to the modeled 2011 concentration in each grid cell and multiply that by the corresponding 2011 eVNA quarterly $PM_{2.5}$ component species value in that grid cell (Equation 13).

$$eVNA_{g,s,q,future} = \left(eVNA_{g,s,q,2011}\right) \times \frac{Model_{g,s,q,future}}{Model_{g,s,q,2011}} \quad \text{(Eq-13)}$$

This results in a gridded future-year projection which accounts for adjustments to match observations in the 2011 modeled data.

Finally, particulate ammonium concentrations are impacted both by emissions of precursor ammonia gas as well as ambient concentrations of particulate sulfate and nitrate.

[18] In this analysis the "future year" modeled concentration is the result of Equations 9, 10, or 11 that represents either the ACE scenarios.

Because of uncertainties in ammonium speciation measurements combined with sparse ammonium measurements in rural areas, the SMAT-CE default is to calculate ammonium values using the degree of sulfate neutralization (i.e., the relative molar mass of ammonium to sulfate with the assumption that all nitrate is fully neutralized). Degree of neutralization values are mainly available in urban areas while sulfate measurements are available in both urban and rural areas. Ammonium is thus calculated by multiplying the interpolated degree of neutralization value by the interpolated sulfate value at each grid-cell location which allows the ammonium fields to be informed by rural sulfate measurements in locations where no rural ammonium measurements are available. The degree of neutralization is not permitted to exceed the maximum theoretical molar ratio of 2:1 for ammonium sulfate. When creating the future year surface for particulate ammonium, we use the default SMAT-CE assumption that the degree of neutralization for the aerosol remains at 2011 levels.

A similar method for creating future-year eVNA surfaces is followed for the two ozone metrics with a few key differences. First, while $PM_{2.5}$ is split into quarterly averages and then averaged up to an annual value, we look at ozone as a summer-season average using definitions that match metrics from epidemiology studies (May-Sep for MDA8 and Apr-Oct for MDA1). The other main difference in the SMAT-CE calculation for ozone is that the spatial interpolation of observations uses an inverse distance weighting rather than an inverse distance squared weighting. This results in interpolated observational fields that better replicate the more gradual spatial gradients observed in ozone compared to $PM_{2.5}$.

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CHAPTER 4: COST, EMISSIONS, AND ENERGY IMPACTS

Overview

This chapter reports the compliance costs, emissions, and energy analyses performed for the Revised CSAPR Update final rule. EPA used the Integrated Planning Model (IPM) to conduct most of the analysis discussed in this chapter. As explained in detail below, this chapter presents analysis for three regulatory control alternatives that differ in the level of electric generating units (EGU) nitrogen oxides (NO_X) ozone season emissions budgets in the 12 states subject to this action.[1] These regulatory control alternatives impose different budget levels based on different NO_X mitigation technologies.

The chapter is organized as follows: following a summary of the regulatory control alternatives analyzed and a summary of EPA's methodology, we present estimates of compliance costs, as well as estimated impacts on emissions, generation, capacity, fuel use, fuel price, and retail electricity price.

4.1 Regulatory Control Alternatives

Of the 22 states currently covered by the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 trading program, EPA is establishing revised budgets for 12 states. Therefore, EPA is creating an additional geographic group and ozone season trading program comprised of these 12 upwind states with remaining linkages to downwind air quality problems in 2021. This new group, Group 3, will be covered by a new CSAPR NO_X Ozone Season Group 3 trading program and will no longer be subject to Group 2 budgets. Aside from the removal of the 12 covered states from the current Group 2 program, this rule leaves unchanged the budget stringency and geography of the existing CSAPR NO_X Ozone Season Group 1 and Group 2 trading programs. The EGUs covered by the FIPs and subject to the budget are fossil-fired EGUs with >25 megawatt (MW) capacity.

This regulatory impact analysis (RIA) evaluates the benefits, costs and certain impacts of compliance with three regulatory control alternatives: the final Revised CSAPR Update, a less-

[1] The 12 states for which EPA is promulgating FIPs to reduce interstate ozone transport for the 2008 ozone NAAQS are listed in Table I.A-2 of the preamble and are Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New York, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia.

stringent alternative, and a more-stringent alternative. For details on the derivation of these budgets, please see Section VI of the preamble. Aside from the difference in emission budgets, other key regulatory features of the allowance trading program, such as the ability to bank allowances for future use, are the same across all the three different sets of NO_X emissions budgets analyzed.

4.1.2 Regulatory Control Alternatives Analyzed

In accordance with Executive Orders 12866 and 13563, the guidelines of OMB Circular A-4, and EPA's *Guidelines for Preparing Economic Analyses*, this RIA analyzes the benefits and costs associated with complying with the final Revised CSAPR Update. The illustrative Revised CSAPR Update emission budgets in this RIA represent EGU NO_X ozone season emission budgets for each state that were developed using uniform control stringency represented by $1,800 per ton of NO_X (2016$).[2] This RIA analyzes the illustrative Revised CSAPR Update emission budgets, as well as a more and a less stringent alternative to the final Revised CSAPR Update. The more and less stringent alternatives differ from the final Revised CSAPR Update in that they set different NO_X ozone season emission budgets for the affected EGUs. The less-stringent scenario uses emission budgets that were developed using uniform control stringency represented by $500 per ton of NO_X (2016$). The more-stringent scenario uses emission budgets that were developed using uniform control stringency represented by $9,600 per ton of NO_X (2016$). For details, please see EGU NO_X Mitigation Strategies Final Rule TSD, in the docket for this rule.[3]

All three scenarios are illustrative in nature, and the budgets included in the Revised CSAPR Update scenario differ slightly from the budgets finalized in this rule. That is because subsequent to completion of the analysis of these three scenarios, EPA made minor updates to budgets. In particular, the modeling presented in the RIA assumes that SNCR optimization is available in 2022, whereas the final budgets assume that SNCR optimization is available in 2021. The estimated incremental emission reductions would be 1,163 tons if EPA had used the actual 2021 budgets, or a 1.1% tightening in the modeled budget across the Group 3 states. The choice

[2] The budget setting process is described in section VII of the preamble and in detail in the Ozone Transport Policy Analysis Final Rule Technical Support Document (TSD).
[3] Docket ID No. EPA-HQ-OAR-2020-0272

of 2021 or 2022 for the initial year of SNCR optimization is an exogenous input into the model. EPA finds that the three illustrative regulatory control alternatives presented in this RIA provide a reasonable approximation of the impacts of the final rule, as well as an evaluation of the relative impacts of two regulatory alternatives. This finding is supported by an analysis of the costs and impacts (but not the benefits) of the final Revised CSAPR Update emission budgets assuming 2021 for the initial year of SNCR optimization and provided in the docket for this rulemaking.

Table 4-1 reports the illustrative EGU NO_X ozone season emission budgets that are evaluated in this RIA. As described above, starting in 2021, emissions from affected EGUs in the 12 states cannot exceed the sum of emissions budgets but for the ability to use banked allowances from previous years for compliance. No further reductions in budgets occur after 2024, and budgets remain in place for future years. Furthermore, emissions from affected EGUs in a particular state are subject to the CSAPR assurance provisions, which require additional allowance surrender penalties (a total of 3 allowances per ton of emissions) on emissions that exceed a state's CSAPR NO_X ozone season assurance level, or 121 percent of the emissions budget. Similar to the approach taken in the CSAPR Update, EPA is implementing a one-time conversion of banked Group 2 allowances according to a formula. The size of the initial bank would be set at a level that would ensure that the use of these converted allowances, in addition to the allowances provided in the states' emissions budgets under the Group 3 trading program, would not authorize emissions in the trading program region in the first year of the program to exceed the sum of the states' budgets by more than the sum of the states' variability limits. The CSAPR NO_X ozone season allowance trading program is described in further detail in Section VII of the preamble.

Table 4-1. Illustrative NO_X Ozone Season Emission Budgets (Tons) Evaluated

	Revised CSAPR Update				
State	**2021**	**2022**	**2023**	**2024**	**2025**
Illinois	9,198	9,102	8,179	8,059	8,059
Indiana	13,085	12,582	12,553	9,564	9,564
Kentucky	15,307	14,051	14,051	14,051	14,051
Louisiana	15,389	14,818	14,818	14,818	14,818
Maryland	1,499	1,266	1,266	1,348	1,348
Michigan	12,732	12,290	9,975	9,786	9,786
New Jersey	1,253	1,253	1,253	1,253	1,253
New York	3,416	3,416	3,421	3,403	3,403
Ohio	9,690	9,773	9,773	9,773	9,773
Pennsylvania	8,379	8,373	8,373	8,373	8,373
Virginia	4,614	3,897	3,980	3,663	3,663
West Virginia	13,686	12,884	12,884	12,884	12,884
Total	108,248	103,703	100,525	96,974	96,974
	Less-Stringent Alternative				
State	**2021**	**2022**	**2023**	**2024**	**2025**
Illinois	9,348	9,348	8,393	8,272	8,272
Indiana	15,677	15,206	15,179	12,083	12,083
Kentucky	15,606	15,606	15,606	15,606	15,606
Louisiana	15,430	15,430	15,430	15,430	15,430
Maryland	1,501	1,267	1,267	1,350	1,350
Michigan	13,126	12,688	10,386	10,188	10,188
New Jersey	1,346	1,346	1,346	1,346	1,346
New York	3,463	3,463	3,468	3,450	3,450
Ohio	15,487	15,569	15,569	15,569	15,569
Pennsylvania	11,807	11,806	11,806	11,806	11,806
Virginia	4,661	4,270	4,357	4,021	4,021
West Virginia	15,017	15,017	15,017	15,017	15,017
Total	122,468	121,016	117,822	114,138	114,138
	More-Stringent Alternative[4]				
State	**2021**	**2022**	**2023**	**2024**	**2025**
Illinois	9,198	9,102	8,179	6,891	6,891
Indiana	13,085	12,582	12,553	8,430	8,430
Kentucky	15,307	14,051	14,051	9,775	9,775
Louisiana	15,389	14,818	14,818	12,622	12,622
Maryland	1,499	1,266	1,266	1,168	1,168
Michigan	12,732	12,290	9,975	7,344	7,344
New Jersey	1,253	1,253	1,253	1,257	1,257
New York	3,416	3,416	3,421	3,297	3,297
Ohio	9,690	9,773	9,773	9,222	9,222
Pennsylvania	8,379	8,373	8,373	7,851	7,851
Virginia	4,614	3,897	3,980	3,184	3,184
West Virginia	13,686	12,884	12,884	10,568	10,568
Total	108,248	103,703	100,525	81,609	81,609

Note that EGUs have flexibility in determining how they will comply with the allowance trading program. As discussed below, the way that they comply may differ from the methods forecast in the modeling for this RIA. See Section 4.3 for further discussion of the modeling approach used in the analysis presented below.

4.2 Power Sector Modeling Framework

IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and to examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system. EPA used IPM to project likely future electricity market conditions with and without the Revised CSAPR Update.

IPM, developed by ICF, is a multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides estimates of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints.[5] EPA has used IPM for almost three decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[6]

The model incorporates a detailed representation of the fossil-fuel supply system that is used to estimate equilibrium fuel prices. The model uses natural gas fuel supply curves and regional gas delivery costs (basis differentials) to simulate the fuel price associated with a given

[4] For the illustrative purposes in this RIA, EPA's analytical technique for assessing the more stringent alternative presents emission reduction values incremental to the final rule's stringency prior to 2025. This does not reflect a determination that new SCR controls could be installed on a fleetwide basis before the 2025 ozone season. See sections VI.B.1, C.1, and D.1 of the preamble for further discussion.

[5] Due to the compliance timing for the Revised CSAPR Update, EPA does not allow IPM to build certain new capital investments such as new, unplanned natural gas or renewable capacity or new SCR or SNCR through 2025 in response to the state emission budgets. EPA's compliance modeling does allow for new combustion controls, which represent the most likely potential capital expenditure in the 2022 analysis year.

[6] Detailed information and documentation of EPA's Baseline run using IPM (v6), including all the underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: http://www.epa.gov/airmarkets/powersectormodeling.html.

level of gas consumption within the system. These inputs are derived using ICF's Gas Market Model (GMM), a supply/demand equilibrium model of the North American gas market.[7]

IPM also endogenously models the partial equilibrium of coal supply and EGU coal demand levels throughout the contiguous U.S., taking into account assumed non-power sector demand and imports/exports. IPM reflects 36 coal supply regions, 14 coal grades, and the coal transport network, which consists of over four thousand linkages representing rail, barge, and truck and conveyer linkages. The coal supply curves in IPM were developed during a thorough bottom-up, mine-by-mine approach that depicts the coal choices and associated supply costs that power plants would face if selecting that coal over the modeling time horizon. The IPM documentation outlines the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 36 coal regions' supply curves.[8]

To estimate the annualized costs of additional capital investments in the power sector, EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the power sector's cost of capital (i.e., private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital.[9] It is important to note that there is no single CRF factor applied in the model; rather, the CRF varies across technologies, book life of the capital investments, and regions in the model in order to better simulate power sector decision-making.

EPA has used IPM extensively over the past three decades to analyze options for reducing power sector emissions. Previously, the model has been used to estimate the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule (U.S. EPA, 2005), the original Cross-State Air Pollution Rule (U.S. EPA, 2011), the Mercury and Air Toxics Standards (MATS) (U.S. EPA, 2011a), the Clean Power Plan (CPP) for Existing Power Plants (U.S. EPA, 2015), the Carbon Pollution Standards for New Power Plants (U.S. EPA, 2015), the Affordable

[7] See Chapter 8 of EPA's Baseline run using IPM v6 documentation, available at: https://www.epa.gov/airmarkets/power-sector-modeling-platform-v6-may-2019.

[8] See Chapter 7 of the IPM v.6 documentation. The documentation for EPA's Baseline run v.6 using IPM consists of a comprehensive document for the November 2018 release of IPM v. 6, and incremental update documents for subsequent releases: http://www.epa.gov/airmarkets/powersectormodeling.html.

[9] See Chapter 10 of EPA's Baseline run using IPM (v6) documentation, available at: http://www.epa.gov/airmarkets/powersectormodeling.html

Clean Energy Rule (U.S. EPA, 2019), and the Clean Power Plan Repeal (U.S. EPA, 2019). EPA has also used IPM to estimate the air pollution reductions and power sector impacts of water and waste regulations affecting EGUs, including Cooling Water Intakes (316(b)) Rule (U.S. EPA, 2014), Disposal of Coal Combustion Residuals from Electric Utilities (CCR) (U.S. EPA, 2015b) and Steam Electric Effluent Limitation Guidelines (ELG) (U.S. EPA, 2015c).

The model and EPA's input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly detailed review of key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts. For example, in October 2014 U.S. EPA commissioned a peer review[10] of EPA Baseline run version 5.13 using the Integrated Planning Model. Additionally, and in the late 1990s, the Science Advisory Board reviewed IPM as part of the CAA Amendments Section 812 prospective studies[11] that are periodically conducted. The Agency has also used the model in a number of comparative modeling exercises sponsored by Stanford University's Energy Modeling Forum over the past 15 years. IPM has also been employed by states (e.g., for the Regional Greenhouse Gas Initiative, the Western Regional Air Partnership, Ozone Transport Assessment Group), other Federal and state agencies, environmental groups, and industry.

4.3 EPA's Power Sector Modeling of the Baseline Run and Three Regulatory Control Alternatives

The IPM "baseline run" for any regulatory impact analysis is a business-as-usual scenario that represents expected behavior in the electricity sector under market and regulatory conditions in the absence of a regulatory action. As such, an IPM baseline run represents an element of the baseline for this RIA.[12] EPA frequently updates the IPM baseline run to reflect the latest

[10] See Response and Peer Review Report EPA Baseline run Version 5.13 Using IPM, available at: https://www.epa.gov/airmarkets/response-and-peer-review-report-epa-base-case-version-513-using-ipm.
[11] http://www2.epa.gov/clean-air-act-overview/benefits-and-costs-clean-air-act
[12] As described in Chapter 5 of EPA's *Guidelines for Preparing Economic Analyses*, the baseline "should incorporate assumptions about exogenous changes in the economy that may affect relevant benefits and costs (e.g.,

available electricity demand forecasts from the U.S. Energy Information Administration (EIA) as well as expected costs and availability of new and existing generating resources, fuels, emission control technologies, and regulatory requirements.

4.3.1 EPA's IPM Baseline Run v.6

For our analysis of the Revised CSAPR Update, EPA used the January 2020 release of IPM version 6 to provide power sector emissions data for air quality modeling, as well as a companion updated database of EGU units (the National Electricity Energy Data System, or NEEDS v.6 rev: 1-8-2020[13]) that is used in EPA's modeling applications of IPM. The IPM Baseline run includes both the CSAPR and CSAPR Update. EPA's Affordable Clean Energy (ACE) rule was vacated by the United States Court of Appeals for the District of Columbia Circuit on January 19, 2021. However, since the analysis for this rulemaking was far along by that date, the model includes the ACE rule's effects consistent with the RIA for the final ACE rule. Given the very modest impacts anticipated from the ACE rule on the power sector and associated emissions levels in the relevant years analyzed for this final rule, EPA does not view the vacatur of ACE as sufficiently important to warrant separate analysis. Further, since the rule is included in both the baseline run as well as the three policy alternatives, inclusion of the ACE rule is not likely to significantly affect cost and benefit estimates for this rulemaking. The baseline run includes the 2015 Effluent Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), but does not include the recently finalized 2020 ELG and CCR rules.[14] The analysis of cost and impacts presented in this chapter is based on a single IPM baseline run, and represents incremental impacts projected solely as a result of compliance with the emissions budgets presented in Table 4-1 above.

4.3.2. Methodology for Evaluating the Regulatory Control Alternatives

To estimate the costs, benefits, and economic and energy market impacts of the Revised CSAPR Update, EPA conducted quantitative analysis of the three regulatory control alternatives:

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changes in demographics, economic activity, consumer preferences, and technology), industry compliance rates, other regulations promulgated by EPA or other government entities, and behavioral responses to the rule by firms and the public." (USEPA, 2010).

[13] https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6

[14] For a full list of modeled policy parameters, please see: https://www.epa.gov/sites/production/files/2020-02/documents/incremental_documentation_for_epa_v6_january_2020_reference_case.pdf

the final Revised CSAPR Update emission budgets and a more and a less stringent alternative. Details about these regulatory control alternatives, including state-specific EGU NO_X ozone-season emissions budgets for each alternative as analyzed in this RIA, are provided above in Section 4.1.

Before undertaking power sector analysis to evaluate compliance with the regulatory control alternatives, EPA first considered available EGU NO_X mitigation strategies that could be implemented for the upcoming ozone season (i.e., the 2021 ozone season). EPA considered all widely-used EGU NO_X control strategies: optimizing NO_X removal by existing, operational selective catalytic reduction (SCRs) and turning on and optimizing existing idled SCRs; optimizing existing idled selective non-catalytic reduction (SNCRs); installation of (or upgrading to) state-of-the-art NO_X combustion controls; shifting generation to units with lower NO_X emission rates; and installing new SCRs and SNCRs. EPA determined that affected EGUs within the 12 states could implement all of these NO_X mitigation strategies, except installation of new SCRs or SNCRs and state-of-the-art combustion controls, for the 2021 ozone season.[15] After assessing the available NOx mitigation methods for complying with the annual budgets, this RIA projects that the system-wide least-cost strategies for compliance with the illustrative Revised CSAPR Update budgets presented above and the more and less stringent regulatory alternatives lead to the application of the same controls at the same sources as in the analysis used to calculate the budgets for these alternatives. As a consequence, the sectoral analyses used to establish the budgets are the same analyses used to estimate the compliance cost, benefits, and impacts of the Revised CSAPR Update and the more stringent and less stringent alternatives. In the analysis of the rule presented in this RIA, in each year of the analysis period (2021-2040) and in each of the 12 states subject to tighter seasonal NOx budgets, seasonal NOx emissions from the sources subject to the rule equal the seasonal NOx budget. For more details on these assessments, including the assessment of EGU NO_X mitigation costs and feasibility, please refer to the EGU NO_X Mitigation Strategies Final Rule TSD, in the docket for this rule.[16]

[15] The modeling presented in this RIA assumes that SNCR optimization is available starting in 2022. This choice reflects an exogenous input into the model.
[16] Docket ID No. EPA-HQ-OAR-2020-0272

These mitigation strategies are primarily captured within the model. However, due to limitations on model size, IPM v.6 does not have the ability to endogenously determine whether or not to operate existing EGU post-combustion NO_X controls (i.e., SCR or SNCR) in response to a regulatory emissions requirement.[17] The operating status of existing post-combustion NO_X controls at a particular EGU in a model scenario is determined by the model user. In order to evaluate compliance with the regulatory alternatives, EPA determined outside of IPM whether or not operation of existing controls that are idle in the baseline would be reasonably expected for compliance with each of the evaluated regulatory alternatives and for which model years they can feasibly be applied. IPM includes optimization and perfect foresight in solving for least cost dispatch. Given that the final rule will become effective soon after the start of the 2021 ozone season, to avoid overstating optimization and dispatch decisions that are not possible in that short time frame, EPA complemented the projected IPM EGU outlook with historical (e.g., engineering analytics) perspective based on historical data that only factors in known changes to the fleet. This analysis forms the basis for the benefits calculations presented in this RIA.

EPA considers a unit to have optimized use of an SCR if emissions rates are equal to (or below) the "widely achievable" rate of 0.08 lbs/MMBtu.[18] Within IPM, units with extant SCRs are defined as SCR-equipped units with ozone season NO_X emission rates less than 0.20 lbs/ MMBtu in the baseline run. These units had their emission rates lowered to the lower of their mode 4[19] NO_X rate in NEEDS and the "widely achievable" optimized emissions rate of 0.08 lbs/ MMBtu in the final Revised CSAPR Update. Units equipped with SCRs with an emissions rate exceeding 0.20 lbs/ MMBtu were considered to have idled SCRs. These units had their emission rates lowered to the lower of their mode 4 NO_X rate in NEEDS and the "widely achievable" optimized emissions rate of 0.08 lbs/ MMBtu in the Revised final Revised CSAPR Update.[20] These control options (optimizing partially operating SCR controls or turning on idled SCR

[17] EGUs with idled SCR or SNCR in the baseline run represent a small percentage (less than 10 percent) of the EGU fleet that is equipped with NO_X post-combustion controls.
[18] For details on the derivation of this standard, please see preamble Section VII.B.1.
[19] NEEDS includes four possible states of NOx control operations, designated Modes 1-4. For details, please see Chapter 3.9.3 of IPM v6 documentation available at: https://www.epa.gov/sites/production/files/2018-08/documents/epa_platform_v6_documentation_-_all_chapters_august_23_2018_updated_table_6-2.pdf.
[20] EPA updated the total emission reduction potential for each technology based on information provided by commenters where EPA determined that information to be credible. Further details are provided in the Response to Comment document included in the docket and in the Ozone Transport Policy Analysis Final Rule TSD.

controls) are achievable in 2021 and were associated with a uniform control cost of $800 per ton and $1,600 per ton respectively. No further adjustments were made to the variable and fixed operating cost of these units, and their heat rates were also not adjusted to reflect energy requirements from increasing SCR removal efficiency within IPM. Under the proposed rule, 47 units are projected to fully run existing SCR controls, while 4 units are projected to turn on idled SCR controls.

EPA considers a unit to have optimized use of an SNCR if NOx emissions rates are equal to or less than the mode 2 rate from the NEEDS database (June 2020). As described in EPA's power sector IPM Modeling Documentation (Chapter 3), these unit-specific NOx mode rates are calculated from historical data and reflect operation of existing post-combustion controls. Mode 2 for SNCR-controlled coal units is intended to reflect the operation of that unit's post combustion control based on prior years when that unit operated its control. Hence any units with existing SNCRs with NOx emission rates greater than their mode 2 rates in the 12-state region had their rates lowered to their mode 2 rates. The illustrative budgets assume these control options as being achievable in 2022 and were associated with a uniform control cost of $1,800 per ton.[21] No further adjustments were made to the variable and fixed operating cost of these units, and their heat rates were also not adjusted to reflect energy requirements from increasing SNCR removal efficiency within IPM. Units with potential SNCR optimization-based emission reductions and their corresponding emissions, heat input, and emission rate are shown in Appendix A of the Ozone Transport Policy Analysis Final Rule TSD.

Finally, unit combustion control configurations listed in NEEDS were compared against Table 3-11 in the Documentation for EPA Baseline run v.5.13 Using the Integrated Planning Model IPM v.6, which lists state-of-the-art combustion control configurations based on unit firing type. This allowed EPA to identify units that would receive state-of-the-art combustion control upgrades in IPM. EPA then followed the procedure in the EGU NOx Mitigation Strategies Final Rule TSD to calculate each of these unit's new NO_X emission rate. These upgrades were assumed to occur in 2022 and were assigned a uniform control cost of $1,600 per

[21] EPA notes that the final rule implements state emissions budgets reflecting SNCR optimization starting in 2021. The Agency conducted additional sensitivity analysis using IPM demonstrating that the 2021 implementation made no significant difference in the cost implications described in the body of the RIA. EPA provides that IPM scenario in the docket for this rulemaking.

ton. No further adjustments were made to the variable and fixed operating cost of these units, and their heat rates were also not adjusted to reflect increased energy input requirements at a given load from the use of additional combustion controls, within IPM. Under the final Revised CSAPR Update, 10 units are projected to install state-of-the-art combustion controls.

The EGU NO_X mitigation strategies that are assumed to operate or are available to reduce NO_X in response to each of the regulatory control alternatives are shown in Table 4-2; more information about the estimated costs of these controls can be found in the EGU NO_X Mitigation Strategies Final Rule TSD.

Table 4-2. NO_X Mitigation Strategies Represented in Modeling of the Regulatory Control Alternatives

Regulatory Control Alternative	NO_X Controls Implemented
Less Stringent Alternative	(1) Shift generation to minimize costs (costs estimated within IPM)
Revised CSAPR Update Rule	(All controls above) (2) Fully operating existing SCRs to achieve 0.08 lb/MMBtu NOx emission rate (costs estimated outside IPM) (3) Turn on idled SCRs (costs estimated outside IPM) and fully operate akin to (2) (4) Fully operate existing SNCRs (costs estimated outside IPM) (5) Install state-of-the-art combustion controls.
More Stringent Alternative	(All controls above) (6) In 2025, impose state emission limits commensurate with installation of new SCRs on units without such controls. However, additional SCRs controls are not a least-cost compliance strategy. (costs estimated within IPM)

For the NO_X controls identified in Table 4-2, under the final rule and the more stringent alternative, 47 units, not already doing so in 2019, are projected to fully operate existing SCRs and 4 units are projected to turn on idled SCRs. Under the less stringent alternative, no units are projected to either fully operate existing SCRs or turn on idled SCRs. Under the final rule and the more stringent alternative, 29 units are projected to fully operate existing SNCRs, and under the less stringent alternative no units are projected to fully operate SNCR controls. Under the final rule and the more stringent alternative, 10 units are projected to install state-of-the-art combustion controls, and under the less stringent alternative no units are projected to install state-of-the-art combustion controls. The book-life of the controls is assumed to be 15 years.

Under the final rule, the more stringent alternative, and the less stringent alternative, no units are projected to install new SCRs.[22] The book-life of the new SCRs is assumed to be 15 years.

In addition to the limitation on ozone season NO_X emissions required by the EGU emissions budgets for the 12 states, there are four important features of the allowance trading program represented in the model that may influence the level and location of NO_X emissions from affected EGUs, including: the ability of affected EGUs to buy and sell NO_X ozone season allowances from one another for compliance purposes; the ability of affected EGUs to bank NO_X ozone season allowances for future use; the effect of limits on the total ozone season NO_X emissions from affected EGUs in each state required by the assurance provisions; and the treatment of banked pre-2021 vintage NO_X ozone season allowances issued under the CSAPR Update program now being revised under this final rule. Each of these features of the ozone season allowance trading program is described below.

Affected EGUs are expected to choose the least-cost method of complying with the requirements of the allowance trading program, and the distribution of ozone season NO_X emissions across affected EGUs is generally governed by this cost-minimizing behavior in the analysis. The total ozone season NO_X emissions from affected EGUs in this analysis are limited to the amount allowed by the sum of the NO_X budgets across the 12 states. Furthermore, allowances may be banked for future use. The number of banked allowances is influenced by the determination, outside the model, of whether (i) existing controls that are idle in the baseline run are turned on and (ii) it is less costly to abate ozone season NO_X emissions in a current ozone season than to abate emissions in a later ozone season. Affected EGUs are expected to bank NO_X ozone season allowances in the 2021 ozone season for use in a later ozone season. The model starts with an assumed bank level in 2021 and endogenously determines the bank in each subsequent year. Based on observation, EPA believes that this is a reasonable compliance path for EGUs, even though there may be other non-economic reasons, such as being prepared for future variability in power sector operations, that can potentially influence this decision.

[22] Under the proposed rule, units were exogenously forced to install SCR controls in IPM. In the modeling for the final rule, the choice to install SCR controls was endogenous to the model, and no incremental SCR installations occurred, with the model relying on greater levels of generation shifting instead.

While there are no explicit limits on the exchange of allowances between affected EGUs and on the banking of 2021 and future-year vintage NO_X ozone season allowances, the assurance provisions limit the amount of seasonal NO_X emissions by affected EGUs in each of the 12 states. The assurance level limits affected EGU emissions over an ozone season to the state's NO_X ozone season emissions budget plus an increment equal to 21 percent of each state's emissions budget. This increment is called the variability limit. See Section VII.C.4 of the preamble for a discussion of the purpose of the assurance provision and further detail about how the variability limits and assurance levels are determined. If a state exceeds its assurance level in a given year, sources within that state are assessed a 3-to-1 allowance surrender penalty on the excess tons. Section VII.C.4 of the preamble also explains how EPA then determines which EGUs are subject to this surrender requirement. In the modeling, the assurance provisions are represented by a limit on the total ozone season NO_X emissions that may be emitted by affected EGUs in each state, and thus the modeling does not permit affected EGUs to emit beyond the assurance levels and thus incur penalties.

As described in Section VII.D.4 of the preamble, the rule allows pre-2021 vintage NO_X ozone season allowances (that had been issued under the CSAPR Update program now being revised under this rule) to be used for compliance with this rule, following a one-time conversion that reduces the overall quantity of banked allowances from that time period. Based on EPA's expectation of the size of the NO_X allowance bank after the one-time conversion carried out pursuant to the terms of this rule, the treatment of these banked allowances is represented in the modeling as an additional 22,737 tons of NO_X allowances, the equivalent of one year of the variability limit associated with the emission budgets, that may be used by affected EGUs during the 2021 ozone season or in later ozone seasons under the final Revised CSAPR Update. Under the more stringent and less stringent alternatives an additional 22,732 tons and 25,718 tons respectively may be used by affected EGUs during the 2021 ozone season or in later ozone seasons.

4.3.3 Methodology for Estimating Compliance Costs

This section describes EPA's approach to quantify estimated compliance costs associated with the three illustrative regulatory control alternatives. These compliance costs include estimates projected directly by the model as well as calculations performed outside of the model that use IPM model inputs and methods. The model projections capture the costs associated with shifting generation to lower-NO_X emitting EGUs. The costs of increasing the use and optimizing the performance of existing and operating SCRs and SNCRs,[23] and for installing or upgrading NO_X combustion controls, were estimated outside of the model. The costs for these three NO_X mitigation strategies are calculated based on engineering analytics emissions projections and use the same NO_X control cost equations used in IPM. Therefore, this estimate is consistent with modeled projections and provides the best available quantification of the costs of these NO_X mitigation strategies.

The following steps summarize EPA's methodology for estimating the component of compliance costs that are calculated outside of the model for the final rule alternative in 2021[24]:

(1) In the model projections, identify all EGUs in the 12 states that can adopt the following NO_X mitigation strategies:

- Fully operating existing SCRs
- Fully operating existing SNCRs
- Installing state-of-the-art combustion controls

(2) Estimate the total NO_X reductions that are attributable to each of these strategies:[25]

- Fully operating existing SCRs (SCRs operating in baseline run): 7,447 tons
- Fully operating existing SCRs (SCRs not operating in baseline run): 5,870 tons
- Fully operating existing SNCRs (not available in 2021 in the illustrative scenarios modeled): 0 tons[26]
- Installing state-of-the-art combustion controls (not available in 2021): 0 tons

[23] This includes optimizing the performance of SCRs that were not operating.
[24] For more information on the derivation of costs and useful life of combustion controls, please see EGU NO_X Mitigation Strategies Final Rule TSD.
[25] For more information on how NO_X reductions were attributed to strategies, see the Ozone Transport Policy Analysis Final Rule TSD.
[26] The estimated emission reductions would be 1,163 tons if EPA had used the actual 2021 budgets. (The selection of 2022 rather than 2021 was an exogenous input to the model.)

(3) Estimate the average cost associated with each of these strategies:[27]

- Fully operating existing SCRs (SCRs operating in baseline run): $800/ton
- Fully operating existing SCRs (SCRs not operating in baseline run): $1,600/ton
- Fully operating existing SNCRs: $1,800/ton[28]
- Installing state-of-the-art combustion controls: $1,600/ton

(4) Multiply (2) by (3) to estimate the total cost associated with each of these strategies.

Table 4-3 summarizes the results of this methodology for the final rule alternative in 2021.

Table 4-3. Summary of Methodology for Calculating Compliance Costs Estimated Outside of IPM for Revised CSAPR Update Final Rule, 2021 (2016$)

NO_X Mitigation Strategy	NO_X Ozone Season Emissions (tons)	Average Cost ($/ton)	Total Cost ($MM)
Optimize existing SCRs	7,447	$800	$6
Operate existing SCRs	5,870	$1,600	$9

EPA exogenously updated the emissions rates for the identified EGUs within the 12 states consistent with the set of controls determined for 2021-2025 within IPM. The model was updated to incorporate the emissions budgets identified for each case, and the first-year bank adjustment as outlined in Section 4.3.2. The Group 2 regional trading program was updated to exclude the 12-state Group 3 regional trading program, and budgets for the remaining Group 2 states were left otherwise unchanged. The change in the reported power system production cost between this model run and the baseline run was used to capture the cost of generation shifting. The total costs of compliance with the regulatory control alternatives are estimated as the sum of the costs that are modeled within IPM and the costs that are calculated outside the model.

[27] See EGU NO_X Mitigation Strategies Final Rule TSD for derivation of cost-per-ton estimates for fully operating SCRs and upgrading to state-of-the-art combustion controls.
[28] If SNCRs were fully operated in 2021 an additional $2 million (2016$) cost would be incurred.

4.4 Estimated Impacts of the Regulatory Control Alternatives

4.4.1 Emission Reduction Assessment

As discussed in Chapter 1, EPA determined that NO_X emissions in 12 eastern states affect the ability of downwind states to attain and maintain the 2008 ozone NAAQS. For these 12 eastern states, EPA is issuing Federal Implementation Plans (FIPs) that update the existing CSAPR Update NO_X ozone-season emission budgets for EGUs and implement these budgets via the CSAPR NO_X ozone-season allowance trading program.

As indicated in Chapter 1, the NO_X emissions reductions are presented in this RIA from 2021 through 2040. The 2021 emissions estimates are based on IPM projections for 2021, and adjustments to account for historical data. For more information on these and other adjustments, see the Ozone Transport Policy Analysis Final Rule TSD.

Table 4-4 presents the estimated reduction in power sector NO_X emissions resulting from compliance with the evaluated regulatory control alternatives (i.e., emissions budgets) in the 12 states, as well as the impact on other states. The emission reductions follow an expected pattern: the less stringent alternative produces substantially smaller emissions reductions than the final rule emissions budgets, and the more stringent alternative results in slightly more NO_X emissions reductions.

Table 4-4. EGU Ozone Season NO_X Emissions and Emissions Changes (thousand tons) for the Baseline Run and the Regulatory Control Alternatives

Ozone Season NO_X (thousand tons)		Total Emissions				Change from Baseline Run		
		Baseline Run	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative
2021	12 States	124	108	122	108	-16	-2	-16
	Other States	236	236	236	236	0	0	0
	Total	360	344	358	344	-16	-2	-16
2022	12 States	123	104	121	104	-19	-2	-19
	Other States	233	233	233	233	0	0	0
	Total	355	337	354	337	-19	-2	-19
2023	12 States	119	101	118	101	-19	-2	-19
	Other States	222	222	222	222	0	0	0
	Total	341	322	340	322	-19	-2	-19
2024	12 States	116	97	114	82	-19	-2	-34
	Other States	218	218	218	218	0	0	0
	Total	334	315	332	300	-19	-2	-34
2025	12 States	116	97	114	82	-19	-2	-34
	Other States	218	218	218	218	0	0	0
	Total	334	315	332	300	-19	-2	-34
2030	12 States	91	78	89	66	-13	-2	-25
	Other States	207	207	207	207	0	0	0
	Total	298	285	297	274	-13	-2	-25
2035	12 States	90	77	89	66	-13	-2	-24
	Other States	207	207	207	207	0	0	0
	Total	298	285	296	273	-13	-2	-24
2040	12 States	90	77	88	66	-13	-2	-24
	Other States	207	207	207	207	0	0	0
	Total	298	285	296	274	-13	-2	-24

The results of EPA's analysis show that, with respect to compliance with the EGU NO_X emission budgets in 2021, maximizing the use of existing operating SCRs provides the largest amount of ozone season NO_X emission reductions (47 percent, affecting 47 units), and turning on idled SCRs produces an additional 37 percent (affecting 4 units) of the total ozone season NO_X reductions. Generation shifting primarily from coal to gas generation (16 percent) makes up the remainder of the ozone season NO_X reductions. Based on this analysis of how EGUs are expected to comply with the final Revised CSAPR Update combining IPM model projections with historical (e.g., engineering analytics) perspective based on historical data that only factors in known changes to the fleet, none of the Group 3 states are projected to hit their variability limits, nor bank or withdraw a substantial additional number of allowances above the starting bank during the analysis period (2021-2025).[29]

If EPA were to have included SNCR optimization in 2021, with respect to compliance with the EGU NO_X emission budgets in 2021, maximizing the use of existing operating SCRs provides the largest amount of ozone season NO_X emission reductions (44 percent, affecting 47 units), turning on idled SCRs produces an additional 35 percent (affecting 4 units) of the total ozone season NO_X reductions, and fully operating existing SNCRs produces an additional 6 percent of reductions (affecting 29 units). Generation shifting primarily from coal to gas generation (15 percent) makes up the remainder of the ozone season NO_X reductions.

In addition to the ozone season NO_X reductions, there will also be reductions of other air emissions associated with EGUs burning fossil fuels (i.e., co-pollutants). These other emissions include the annual total changes in emissions of NOx and CO_2 as well as partially-estimated changes in emissions for SO_2 and direct $PM_{2.5}$ emissions. EPA relied on Engineering Analysis to account for changes in NOx (annual and ozone season), SO_2, and direct PM. While this approach captures the impact of generation shifting for NOx emissions, it does not fully capture the impact of generation shifting for SO_2 and direct PM in complying with the Revised CSAPR Update budgets. EPA did not analyze changes in emissions due to generation shifting for either SO_2 or $PM_{2.5}$ because the majority of the reductions associated with this rulemaking are tied to the operation of SCR and SNCR controls (which do not affect SO_2 emission rates) and state of the art combustion controls (which have a minimal impact on SO_2 emission rates). Additionally in order to meet the court-ordered timeline for this rulemaking EPA prioritized fully capturing the impact of reductions from generation shifting on NOx and CO_2, but did not account for the relatively small amount of SO_2 and primary PM emissions reductions that would likely occur due to generation shifting. Hence total benefits could be higher than those reported in this RIA. EPA relied on IPM estimates to capture changes in CO_2 emissions, which fully account for the impact

[29] As shown in Table 4-4, in 2021 and 2025 seasonal NOx emissions from affected EGUs in the Group 3 states are projected to emit at levels equal to the seasonal budget, and therefore (i) will not bank additional allowances, or (ii) on net, use any banked allowances available at the end of the previous year or, in the case of 2021, from the starting bank.

of generation shifting. The emissions reductions are presented in Table 4-5. Consistent with the limited impact of generation shifting, there were de minimis emissions changes of CO, mercury, and HCl.

Table 4-5. EGU Annual Emissions and Emissions Changes for NO_X, SO_2, $PM_{2.5}$, and CO_2 for the Regulatory Control Alternatives

Annual NO_X (thousand tons)		Total Emissions				Change from Baseline Run		
		Baseline Run	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative
2021	12 States	291	275	289	275	-16	-2	-16
	Other States	524	524	524	524	0	0	0
	Total	815	799	814	799	-16	-2	-16
2022	12 States	287	265	285	265	-22	-2	-22
	Other States	517	517	517	517	0	0	0
	Total	804	782	802	782	-22	-2	-22
2023	12 States	280	258	278	258	-22	-2	-22
	Other States	490	490	490	490	0	0	0
	Total	769	748	768	748	-22	-2	-22
2024	12 States	271	249	269	234	-21	-2	-37
	Other States	482	482	482	482	0	0	0
	Total	753	731	751	716	-21	-2	-37
2025	12 States	271	249	269	234	-21	-2	-37
	Other States	482	482	482	482	0	0	0
	Total	753	731	751	716	-21	-2	-37
2030	12 States	209	193	207	182	-16	-2	-27
	Other States	458	458	458	458	0	0	0
	Total	666	651	665	639	-16	-2	-27
2035	12 States	207	193	206	181	-15	-2	-26
	Other States	458	458	458	458	0	0	0
	Total	665	650	663	639	-15	-2	-26
2040	12 States	207	193	205	182	-14	-2	-25
	Other States	458	458	458	458	0	0	0
	Total	665	651	663	640	-14	-2	-25

Annual SO_2* (thousand tons)		Total Emissions				Change from Baseline Run		
		Baseline Run	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative
2021	12 States	374	374	374	374	0	0	0
	Other States	556	556	556	556	0	0	0
	Total	930	930	930	930	0	0	0
2022	12 States	371	371	371	371	0	0	0
	Other States	545	545	545	545	0	0	0
	Total	916	916	916	916	0	0	0
2023	12 States	347	347	347	347	0	0	0
	Other States	528	528	528	528	0	0	0
	Total	874	874	874	874	0	0	0
2024	12 States	340	340	340	340	0	0	0
	Other States	518	518	518	518	0	0	0
	Total	858	858	858	858	0	0	0
2025	12 States	340	340	340	340	0	0	0
	Other States	518	518	518	518	0	0	0
	Total	858	858	858	858	0	0	0
2030	12 States	234	234	234	234	0	0	0
	Other States	503	503	503	503	0	0	0
	Total	737	737	737	737	0	0	0
2035	12 States	233	233	233	233	0	0	0
	Other States	503	503	503	503	0	0	0
	Total	736	736	736	736	0	0	0
2040	12 States	231	231	231	231	0	0	0
	Other States	503	503	503	503	0	0	0
	Total	734	734	734	734	0	0	0

Annual Direct $PM_{2.5}$* (thousand tons)		Total Emissions				Change from Baseline Run		
		Baseline Run	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**
2021	12 States	50	50	50	50	0	0	0
	Other States	76	76	76	76	0	0	0
	Total	126	126	126	126	0	0	0
2022	12 States	50	50	50	50	0	0	0
	Other States	76	76	76	76	0	0	0
	Total	126	126	126	126	0	0	0
2023	12 States	50	50	50	50	0	0	0
	Other States	73	73	73	73	0	0	0
	Total	122	122	122	122	0	0	0
2024	12 States	48	48	48	48	0	0	0
	Other States	72	72	72	72	0	0	0
	Total	120	120	120	120	0	0	0
2025	12 States	48	48	48	48	0	0	0
	Other States	72	72	72	72	0	0	0
	Total	120	120	120	120	0	0	0
2030	12 States	40	40	40	40	0	0	0
	Other States	70	70	70	70	0	0	0
	Total	110	110	110	110	0	0	0
2035	12 States	41	41	41	41	0	0	0
	Other States	70	70	70	70	0	0	0
	Total	111	111	111	111	0	0	0
2040	12 States	42	42	42	42	0	0	0
	Other States	70	70	70	70	0	0	0
	Total	112	112	112	112	0	0	0

Annual CO_2 (million tons)		Total Emissions				Change from Baseline Run		
		Baseline Run	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative
2021	12 States	478	478	478	478	0	0	0
	Other States	959	959	959	959	0	0	0
	Total	1,437	1,437	1,437	1,437	0	0	0
2022	12 States	507	505	505	503	-3	-2	-4
	Other States	985	986	985	986	0	0	0
	Total	1,493	1,490	1,491	1,489	-2	-2	-4
2023	12 States	537	532	533	528	-5	-4	-9
	Other States	1,011	1,012	1,011	1,012	0	0	1
	Total	1,548	1,543	1,544	1,540	-5	-4	-8
2024	12 States	532	527	528	520	-5	-4	-11
	Other States	1,004	1,004	1,004	1,005	0	0	1
	Total	1,536	1,530	1,531	1,525	-5	-4	-10
2025	12 States	526	521	523	512	-5	-4	-14
	Other States	996	996	996	998	0	0	2
	Total	1,523	1,518	1,519	1,511	-5	-4	-12
2030	12 States	534	526	528	515	-8	-6	-19
	Other States	920	922	921	925	2	2	5
	Total	1,454	1,448	1,450	1,440	-5	-4	-14
2035	12 States	504	500	502	492	-4	-3	-13
	Other States	903	903	903	903	0	0	1
	Total	1,407	1,403	1,404	1,395	-4	-3	-12
2040	12 States	512	507	508	496	-4	-3	-15
	Other States	928	928	929	931	0	0	2
	Total	1,440	1,436	1,437	1,427	-4	-3	-13

* There are no annual SO_2 and $PM_{2.5}$ emissions reductions that come from turning on SCRs and SNCRs assuming that nothing else changes, but EPA did not analyze the effects on SO_2 and direct PM that may come from shifting power generation, for example from coal-fired power plants to gas-fired or other types of power plants. EPA does expect some changes in SO_2 and $PM_{2.5}$ emissions due to shifting of power generation.

4.4.2 Impact of Emissions Reductions on Maintenance and Nonattainment Monitors

In 2021, there are two nonattainment receptors and two maintenance receptors (see section V.C of the preamble for additional discussion). EPA evaluated the air quality improvements at the four receptors for the three EGU emission control technologies that are available in the near-term and that comprise the selected control stringency of the final rule. EPA determined that the average air quality improvement at the four receptors relative to the engineering analytics baseline run was 0.165 ppb for optimization of existing SCRs and LNB upgrades, and 0.17 ppb when also including optimization of existing SNCRs (see Table VI.D.1-1 in the preamble for additional discussion). EPA found that one of the receptors (Westport, Connecticut receptor) remains nonattainment across these control stringencies in 2021, another receptor (Stratford, Connecticut receptor) switches from nonattainment to maintenance with the optimization of existing SCRs (i.e., its average design value (DV)[1] falls below the standard but its maximum DV remains above the NAAQS), while a third receptor (Houston receptor) remains maintenance across these control stringencies.[2]

EPA observes these control stringencies result in all downwind air quality problems for the 2008 ozone NAAQS being resolved after 2024 (one year earlier than the baseline run). There are also projected changes in receptor status (from projected nonattainment to maintenance-only) for the Stratford and Westport receptors (the first in 2021, the second in 2024). In addition, the Houston receptor changes from maintenance to attainment in 2023.

4.4.3 Compliance Cost Assessment

The estimates of the changes in the cost of supplying electricity for the regulatory control alternatives are presented in Table 4-6. Since the rule does not result in any additional recordkeeping, monitoring or reporting requirements, the costs associated with compliance, monitoring, recordkeeping, and reporting requirements are not included within the estimates in this table and can be found in preamble Section VII.C.6.

[1] The DV is calculated as the 3-year average of the annual 4th highest daily maximum 8-hour ozone concentration in parts per billion, with decimals truncated. The DV is a metric compared to the standard level to determine whether a monitor is violating the NAAQS.
[2] The fourth receptor was clean in the engineering baseline run, which is the starting point for a Step 3 analysis.

Table 4-6. National Compliance Cost Estimates (millions of 2016$) for the Regulatory Control Alternatives

	Revised CSAPR Update	More-Stringent Alternative	Less-Stringent Alternative
2021-2025 (Annualized)	$10.0	$41.4	$(2.9)
2021-2040 (Annualized)	$24.8	$28.5	$19.6
2021 (Annual)	$5.1	$5.2	$1.6
2022 (Annual)	$19.2	$61.5	$5.9
2023 (Annual)	$19.2	$61.5	$5.9
2024 (Annual)	$2.1	$4.5	$(14.9)
2025 (Annual)	$1.6	$4.0	$(14.9)
2030 (Annual)	$63.6	$32.3	$67.0
2035 (Annual)	$18.2	$41.2	$14.3
2040 (Annual)	$8.8	$134.0	$ 18.9

"2021-2025 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2021 through 2025 and discounted using a 4.25 real discount rate.[3] This does not include compliance costs beyond 2025. "2021-2040 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2021 through 2040 and discounted using a 4.25 real discount rate. This does not include compliance costs beyond 2040. "2021 (Annual)" through "2040 (Annual)" costs reflect annual estimates in each of those years.[4]

There are several notable aspects of the results presented in Table 4-6. The most notable result in Table 4-6 is that the estimated annual compliance costs for the less stringent alternative is negative (i.e., a cost reduction) in 2024 and 2025, although this regulatory control alternative reduces NO_X emissions by 2,000 tons as shown in Table 4-5. While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given the assumption of perfect foresight. IPM's objective function is to minimize the discounted net present value (NPV) of a stream of annual total cost of generation over a multi-decadal time period.[5] For example, with the assumption of perfect foresight it is possible that on a national basis within the model the least-cost compliance strategy may be to delay a new investment or retirement that was projected to occur sooner in the baseline run. Such a delay could result in a lowering of annual cost in an

[3] This table reports compliance costs consistent with expected electricity sector economic conditions. An NPV of costs was calculated using a 4.25% real discount rate consistent with the rate used in IPM's objective function for cost-minimization. The NPV of costs was then used to calculate the levelized annual value over a 5-year period (2021-2025) and a 20-year period (2021-2040) using the 4.25% rate as well. Tables ES-14 and 7-4 report the NPV of the annual stream of costs from 2021-2040 using 3% and 7% consistent with OMB guidance.
[4] Cost estimates include financing charges on capital expenditures that would reflect a transfer and would not typically be considered part of total social costs. Exclusion of these costs would have a minimal impact on the results.
[5] For more information, please see Chapter 2 of the IPM documentation.

early time period and increase it in later time periods. Since the less-stringent alternative is designed to include only generation shifting, it does not necessitate full operation of existing controls, nor installation of new controls, leading to a negative total cost point estimate in 2025, reflecting the decision to delay retirements until later in the forecast period. Under the final rule, fully operating existing SCR controls provides a large share of the total emissions reductions. These options are selected in 2021, while upgrading to state-of-the-art combustion controls and fully operating existing SNCRs are assumed to begin in 2022. Generation shifting costs are positive in 2021 and 2023, but negative in 2025. The result is that the costs in 2021-23 are higher than costs in 2025. Projected costs for the illustrative Revised CSAPR Update peak in 2030 at $63.6 million (2016$) and annualized costs for the 2021-40 period are $24.8 million (2016$). These trends are also consistent with IPM base case projections: total costs increase most rapidly between the 2025 and 2030 run years as the system responds to projected demand growth and baseload capacity retirements by adding capacity, shifting the generation mix and altering inter-regional transmission flows. Hence under the Revised CSAPR Update rule and the less stringent alternative, incremental costs peak in 2030, driven by IPM projected generation shifting costs. Under the more stringent scenario the tighter cap modeled results in higher costs towards the end of the analysis period as well, as the system alters generation and build patterns to accommodate the tighter modeled budgets. To put these costs into context, the incremental 2030 projected cost constitutes 0.04 percent of total projected baseline run system production costs. For comparison, the compliance cost for the Final CSAPR Update was estimated at $154 million (2016$) in 2020.

Under the more stringent alternative, while 2021 includes the same set of controls as under the Revised CSAPR Update, a wider range of technologies is considered in subsequent years. This, combined with a more stringent cap driving generation shifting costs positive in every year, results in costs that grow over the 2021-25 period.

As part of the IPM model runs, the Group 2 regional trading program was updated to exclude the 12-state Group 3 regional trading program, and budgets for the remaining Group 2 states were left otherwise unchanged. The Group 2 states did not exhibit significant changes in projected allowance prices and level and location of Group 2 NO_X emissions between the baseline and regulatory alternatives as a result of this update.

In addition to evaluating annual compliance cost impacts, EPA believes that a full understanding of these three regulatory control alternatives benefits from an evaluation of annualized costs over the 2021-2025 timeframe. Starting with the estimated annual cost time series, it is possible to estimate the net present value of that stream, and then estimate a levelized annual cost associated with compliance with each regulatory control alternative.[6] For this analysis we first calculated the NPV of the stream of costs from 2021 through 2025[7] using a 4.25 percent discount rate. EPA typically uses a 3 and a 7 percent discount rate to discount future year social benefits and social costs in regulatory impact analyses (USEPA, 2010). In this cost annualization we use a 4.25 percent discount rate, which is consistent with the rate used in IPM's objective function for minimizing the NPV of the stream of total costs of electricity generation. This discount rate is meant to capture the observed equilibrium market rate at which investors are willing to sacrifice present consumption for future consumption and is based on a Weighted Average Cost of Capital (WACC).[8] After calculating the NPV of the cost streams, the same 4.25 percent discount rate and 2021-2025 time period are used to calculate the levelized annual (i.e., annualized) cost estimates shown in Table 4-6.[9] The same approach was used to develop the annualized cost estimates for the 2021-2040 timeframe.

Additionally, note that the 2021-2025 and 2021-2040 equivalent annualized compliance cost estimates have the expected relationship to each other; the annualized costs are lowest for the less stringent alternative, and highest for the more stringent alternative.

4.4.4 Impacts on Fuel Use, Prices and Generation Mix

While the Revised CSAPR Update is expected to result in significant NO_X emissions reductions, it is estimated to result in relatively modest impacts to the power sector. While these impacts are relatively small in percentage terms, consideration of these potential impacts is an

[6] The XNPV() function in Microsoft Excel 2013 was used to calculate the NPV of the variable stream of costs, and the PMT() function in Microsoft Excel 2013 is used to calculate the level annualized cost from the estimated NPV.
[7] Consistent with the relationship between IPM run years and calendar years, EPA assigned 2023 compliance cost estimates to both 2022 and 2023 in the calculation of NPV, and 2025 compliance cost to 2024 and 2025. For more information, see Chapter 7 of the IPM Documentation.
[8] The IPM Baseline run documentation (Section 10.4.1 Introduction to Discount Rate Calculations) states "The real discount rate for all expenditures (capital, fuel, variable operations and maintenance, and fixed operations and maintenance costs) in the EPA Platform v6 is 4.25%."
[9] The PMT() function in Microsoft Excel 2013 is used to calculate the level annualized cost from the estimated NPV.

important component of assessing the relative impact of the regulatory control alternatives. In this section we discuss the estimated changes in fuel use, fuel prices, generation by fuel type, capacity by fuel type, and retail electricity prices.

Table 4-7 and Table 4-8 present the percentage changes in national coal and natural gas usage by EGUs in 2021. These fuel use estimates reflect a modest shift to natural gas from coal. The projected impacts in 2025 are similarly small.

Table 4-7. 2021 Projected U.S. Power Sector Coal Use for the Baseline Run and the Regulatory Control Alternatives

	Million Tons				Percent Change from Baseline run		
	Baseline Run	**Revised CSAPR Update**	**Less-Stringent Alt.**	**More-Stringent Alt.**	**Revised CSAPR Update**	**Less-Stringent Alt.**	**More-Stringent Alt.**
Appalachia	85	85	85	85	0.14%	0.09%	0.14%
Interior	115	115	115	115	0.01%	0.01%	0.00%
Waste Coal	0	0	0	0	0.00%	0.00%	0.00%
West	287	286	286	286	-0.07%	-0.05%	-0.09%
Total	487	487	487	487	-0.01%	-0.01%	-0.03%

Table 4-8. 2021 Projected U.S. Power Sector Natural Gas Use for the Baseline Run and the Regulatory Control Alternatives

Trillion Cubic Feet				Percent Change from Baseline run		
Baseline Run	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**
11	11	11	11	0.00%	0.00%	0.00%

Table 4-9 and Table 4-10 present the projected coal and natural gas prices in 2021, as well as the percent change from the baseline run projected as a result of the regulatory control alternatives. These minor impacts in 2021 are consistent with the small changes in fuel use summarized above. The projected impacts in 2025 are similarly very small.

Table 4-9. 2021 Projected Minemouth and Power Sector Delivered Coal Price for the Baseline Run and the Regulatory Control Alternatives

	$/MMBtu				Percent Change from Baseline run		
	Baseline Run	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative
Minemouth	1.21	1.21	1.21	1.21	0.02%	0.03%	0.06%
Delivered	1.87	1.87	1.87	1.87	-0.01%	0.01%	0.00%

Table 4-10. 2021 Projected Henry Hub and Power Sector Delivered Natural Gas Price for the Baseline Run and the Regulatory Control Alternatives

	$/MMBtu				Percent Change from Baseline run		
	Baseline Run	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative
Henry Hub	3.19	3.19	3.19	3.19	-0.02%	0.00%	-0.05%
Delivered	3.24	3.24	3.24	3.24	-0.02%	0.00%	-0.05%

Table 4-11 presents the projected percentage changes in the amount of electricity generation in 2021 by fuel type. Consistent with the fuel use projections and emissions trends above, EPA projects a small overall shift from coal to gas. The projected impact in 2025 is similarly small.

Table 4-11. 2021 Projected U.S. Generation by Fuel Type for the Baseline Run and the Regulatory Control Alternatives

	Generation (TWh)				Percent Change from Baseline run		
	Baseline Run	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative
Coal	797	797	797	797	0.00%	0.00%	0.00%
Natural Gas	1,582	1,582	1,582	1,582	0.00%	0.00%	-0.01%
Nuclear	740	740	740	740	0.00%	0.00%	0.00%
Hydro	304	304	304	304	0.00%	0.00%	0.00%
Non-Hydro RE	536	536	536	536	0.00%	0.00%	0.00%
Oil\Gas Steam	58	58	58	58	0.01%	0.00%	0.07%
Other	34	34	34	34	-0.02%	-0.03%	0.02%
Total	4,051	4,051	4,051	4,051	0.00%	0.00%	0.00%

Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind.

Table 4-12 presents the projected percentage changes in the amount of generating capacity in 2021 and 2025 by primary fuel type. As explained above, none of the regulatory control alternatives are expected to have a net impact on overall capacity by primary fuel type in 2021, and the model was specified accordingly. By 2030 the Revised CSAPR Update is projected to result in 594 MW of incremental coal retirements nationwide relative to the Baseline run, constituting a reduction of 0.4% of national coal capacity. The majority of this capacity reflects early retirement, i.e. retirement by 2025 of units that retired by 2035 in the baseline.

Table 4-12. 2021 and 2025 Projected U.S. Capacity by Fuel Type for the Baseline Run and the Regulatory Control Alternatives

	Capacity (GW)				Percent Change from Baseline run		
2021	**Baseline Run**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**
Coal	216	216	216	216	0.0%	0.0%	0.0%
Natural Gas	421	421	421	421	0.0%	0.0%	0.0%
Nuclear	94	94	94	94	0.0%	0.0%	0.0%
Hydro	107	107	107	107	0.0%	0.0%	0.0%
Non-Hydro RE	184	184	184	184	0.0%	0.0%	0.0%
Oil\Gas Steam	74	74	74	74	0.0%	0.0%	0.0%
Other	8	8	8	8	0.0%	0.0%	0.0%
Total	1,106	1,106	1,106	1,106	0.0%	0.0%	0.0%

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind

	Capacity (GW)				Percent Change from Baseline Run		
2025	**Baseline Run**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**
Coal	167	166	166	166	-0.4%	-0.3%	-0.6%
Natural Gas	418	418	418	418	0.0%	0.0%	0.1%
Nuclear	77	77	77	77	0.5%	0.4%	1.1%
Hydro	110	110	110	110	0.0%	0.0%	0.0%
Non-Hydro RE	231	231	231	231	0.0%	0.0%	0.0%
Oil\Gas Steam	67	67	67	67	0.1%	0.0%	-0.1%
Other	11	11	11	11	0.0%	0.0%	0.0%
Total	1,081	1,081	1,081	1,081	0.0%	0.0%	0.0%

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind

EPA estimated the change in the retail price of electricity (2016$) using the Retail Price Model (RPM).[10] The RPM was developed by ICF for EPA, and uses the IPM estimates of changes in the cost of generating electricity to estimate the changes in average retail electricity prices. The prices are average prices over consumer classes (i.e., consumer, commercial, and industrial) and regions, weighted by the amount of electricity used by each class and in each region. The RPM combines the IPM annual cost estimates in each of the 64 IPM regions with EIA electricity market data for each of the 22 electricity supply regions (shown in Figure 4-1) in the electricity market module of the National Energy Modeling System (NEMS).[11]

Table 4-13 and Table 4-14 present the projected percentage changes in the retail price of electricity for the three regulatory control alternatives in 2021 and 2025, respectively. Consistent with other projected impacts presented above, average retail electricity prices at both the national and regional level are projected to be small. By 2025, EPA estimates that this rule will result in a 0.02 percent increase in national average retail electricity price, or by about 0.02 mills/kWh.

Table 4-13. Average Retail Electricity Price by Region for the Baseline Run and the Regulatory Control Alternatives, 2021

All Sector	2021 Average Retail Electricity Price (2016 mills/kWh)				Percent Change from Baseline Run		
Region	**Baseline Run**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**
MROE	117	117	117	117	0%	0%	0%
NYCW	166	166	166	166	0%	0%	0%
NYLI	134	134	134	134	0%	0%	0%
NYUP	109	109	109	109	0%	0%	0%
RFCE	115	115	115	115	0%	0%	0%
RFCM	91	91	91	91	0%	0%	0%
RFCW	93	93	93	93	0%	0%	0%
SRDA	83	83	83	83	0%	0%	0%
SRGW	87	87	87	87	0%	0%	0%
SRCE	85	85	85	85	0%	0%	0%
SRVC	99	99	99	99	0%	0%	0%
SPSO	88	88	88	88	0%	0%	0%
NATIONAL	99	99	99	99	0%	0%	0%

[10] See documentation available at: https://www.epa.gov/airmarkets/retail-price-model
[11] See documentation available at:
http://www.eia.gov/forecasts/aeo/nems/documentation/electricity/pdf/m068(2014).pdf

Residential Sector	2021 Average Retail Electricity Price (2016 mills/kWh)				Percent Change from Baseline Run		
Region	Baseline Run	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative
MROE	153	153	153	153	0%	0%	0%
NYCW	401	401	401	401	0%	0%	0%
NYLI	174	174	174	174	0%	0%	0%
NYUP	137	137	137	137	0%	0%	0%
RFCE	152	152	152	153	0%	0%	1%
RFCM	146	146	146	146	0%	0%	0%
RFCW	126	126	126	126	0%	0%	0%
SRDA	97	97	97	97	0%	0%	0%
SRGW	107	107	107	107	0%	0%	0%
SRCE	97	97	97	97	0%	0%	0%
SRVC	114	114	114	114	0%	0%	0%
SPSO	103	103	103	103	0%	0%	0%
NATIONAL	122	122	122	122	0%	0%	0%

Commercial Sector	2021 Average Retail Electricity Price (2016 mills/kWh)				Percent Change from Baseline Run		
Region	Baseline Run	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative
MROE	119	119	119	119	0%	0%	0%
NYCW	105	105	105	105	0%	0%	0%
NYLI	115	115	115	115	0%	0%	0%
NYUP	98	98	98	98	0%	0%	0%
RFCE	103	103	103	103	0%	0%	0%
RFCM	70	70	70	70	0%	0%	0%
RFCW	88	88	88	88	0%	0%	0%
SRDA	81	81	81	81	0%	0%	0%
SRGW	83	83	83	83	0%	0%	0%
SRCE	81	81	81	81	0%	0%	0%
SRVC	93	93	93	93	0%	0%	0%
SPSO	85	85	85	85	0%	0%	0%
NATIONAL	93	93	93	93	0%	0%	0%

Industrial Sector	2021 Average Retail Electricity Price (2016 mills/kWh)				Percent Change from Baseline Run		
Region	Baseline Run	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative	Revised CSAPR Update	Less-Stringent Alternative	More-Stringent Alternative

MROE	86	86	86	86	0%	0%	0%
NYCW	94	94	94	94	0%	0%	0%
NYLI	53	53	53	53	0%	0%	0%
NYUP	84	84	84	84	0%	0%	0%
RFCE	72	72	72	72	0%	0%	0%
RFCM	61	61	61	61	0%	0%	0%
RFCW	68	68	68	68	0%	0%	0%
SRDA	68	68	68	68	0%	0%	0%
SRGW	54	54	54	54	0%	0%	0%
SRCE	71	71	71	71	0%	0%	0%
SRVC	83	83	83	83	0%	0%	0%
SPSO	73	73	73	73	0%	0%	0%
NATIONAL	75	75	75	75	0%	0%	0%

Table 4-14. Average Retail Electricity Price by Region for the Baseline Run and the Regulatory Control Alternatives, 2025

All Sector	2025 Average Retail Electricity Price (2016 mills/kWh)				Percent Change from Baseline Run		
Region	**Baseline Run**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**
MROE	115	115	115	115	0%	0%	0%
NYCW	198	198	198	198	0%	0%	0%
NYLI	159	159	159	159	0%	0%	0%
NYUP	135	135	134	134	0%	0%	0%
RFCE	132	132	132	132	0%	0%	0%
RFCM	105	105	105	105	0%	0%	0%
RFCW	104	104	104	104	0%	0%	0%
SRDA	83	83	83	83	0%	0%	0%
SRGW	97	97	97	97	0%	0%	0%
SRCE	83	83	83	83	0%	0%	0%
SRVC	100	100	100	101	0%	0%	0%
SPSO	93	93	93	93	0%	0%	0%
NATIONAL	105	105	105	105	0%	0%	0%

Residential Sector	2025 Average Retail Electricity Price (2016 mills/kWh)				Percent Change from Baseline Run		
Region	**Baseline Run**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**
MROE	148	148	148	148	0%	0%	0%
NYCW	477	477	477	477	0%	0%	0%
NYLI	210	210	210	210	0%	0%	0%
NYUP	172	172	172	172	0%	0%	0%

RFCE	178	178	178	178	0%	0%	0%
RFCM	171	172	172	172	0%	0%	0%
RFCW	144	144	144	144	0%	0%	0%
SRDA	97	97	97	97	0%	0%	0%
SRGW	119	119	119	119	0%	0%	0%
SRCE	95	95	95	95	0%	0%	0%
SRVC	115	115	115	115	0%	0%	0%
SPSO	108	108	108	108	0%	0%	0%
NATIONAL	130	130	130	130	0%	0%	0%

Commercial	**2025 Average Retail Electricity Price (2016 mills/kWh)**				**Percent Change from Baseline Run**		
Region	**Baseline Run**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**
MROE	117	117	117	117	0%	0%	0%
NYCW	130	130	130	130	0%	0%	0%
NYLI	138	138	138	138	0%	0%	0%
NYUP	120	120	120	120	0%	0%	0%
RFCE	116	116	116	116	0%	0%	0%
RFCM	85	85	85	85	0%	0%	1%
RFCW	101	101	101	101	0%	0%	0%
SRDA	81	81	81	81	0%	0%	0%
SRGW	94	94	94	94	0%	0%	0%
SRCE	80	80	80	80	0%	0%	0%
SRVC	95	95	95	95	0%	0%	0%
SPSO	90	90	90	90	0%	0%	0%
NATIONAL	99	99	99	99	0%	0%	0%

Industrial Sector	**2025 Average Retail Electricity Price (2016 mills/kWh)**				**Percent Change from Baseline Run**		
Region	**Baseline Run**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Revised CSAPR Update**	**Less-Stringent Alternative**	**More-Stringent Alternative**
MROE	86	86	86	86	0%	0%	0%
NYCW	119	119	119	119	0%	0%	0%
NYLI	80	80	80	80	0%	0%	0%
NYUP	106	106	106	106	0%	0%	0%
RFCE	90	89	89	90	0%	0%	0%
RFCM	68	69	69	69	0%	0%	1%
RFCW	75	75	75	76	0%	0%	0%
SRDA	68	68	68	68	0%	0%	0%
SRGW	65	65	65	65	0%	0%	0%
SRCE	70	70	70	70	0%	0%	0%
SRVC	83	83	83	83	0%	0%	0%
SPSO	77	77	77	77	0%	0%	0%

NATIONAL	80	80	80	80	0%	0%	0%

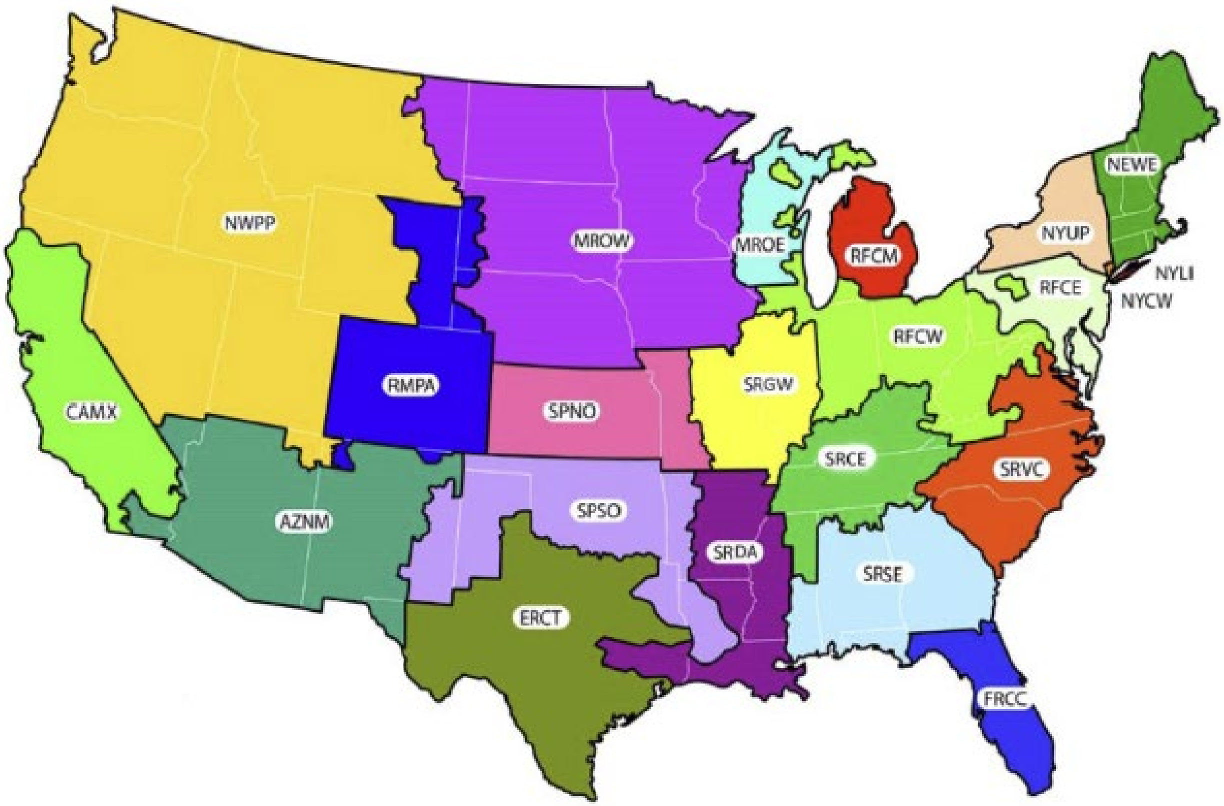

Figure 4-1. Electricity Market Module Regions

Source: EIA (http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf)

4.5 Social Costs

As discussed in EPA's *Guidelines for Preparing Economic Analyses*, social costs are the total economic burden of a regulatory action (USEPA, 2010). This burden is the sum of all opportunity costs incurred due to the regulatory action, where an opportunity cost is the value lost to society of any goods and services that will not be produced and consumed as a result of reallocating some resources towards pollution mitigation. Estimates of social costs may be compared to the social benefits expected as a result of a regulation to assess its net impact on society. The social costs of a regulatory action will not necessarily be equal to the expenditures by the electricity sector to comply with the rule. Nonetheless, here we use compliance costs as a proxy for social costs.

The compliance cost estimates for the rule and more or less stringent regulatory control alternatives presented in this chapter are the change in expenditures by the electricity generating sector required by the power sector for compliance under each alternative. The change in the expenditures required by the power sector to maintain compliance reflect the changes in electricity production costs resulting from application of NO_X control strategies, including changes in expenditures resulting from changes in the mix of fuels used for generation, necessary to comply with the emissions budgets. Ultimately, part of the compliance costs may be borne by electricity consumers through higher electricity prices. As discussed above, the electricity and fossil fuel price impacts from this rule are expected to be small.

4.6 Limitations

EPA's modeling is based on 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.

As described in the preamble at section VII.C.4.C, EPA has introduced a safety valve which gives Group 3 sources the option, in February 2022 only, to purchase additional 2021 Group 3 allowances by surrendering 18 banked 2017-2020 Group 2 allowances per Group 3 allowance. This safety valve was not implemented in the modeling presented in this RIA. However, since the analysis shows that 2021-22 costs remain modest and variability limits are not hit, inclusion of the safety valve would not have changed the modeling results because this option would not have been selected in the model.

The IPM-projected annualized cost estimates of private compliance costs provided in this analysis are meant to show the increase in production (generating) costs to the power sector in response to the rule. To estimate these annualized costs, EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital. The private compliance costs presented earlier are EPA's best estimate of the direct private compliance costs of the rule.

As discussed in section 4.3.2, IPM v6 does not have the capacity to endogenously determine whether or not to maximize the use of existing EGU post-combustion NO_X controls (i.e., SCR), or install/upgrade combustion controls in response to a regulatory control requirement. These decisions were imposed exogenously on the model, as documented in section 4.3.2 and Ozone Transport Policy Analysis Final Rule TSD. While the emissions projections reflect operation of these controls, the projected compliance costs were supplemented with exogenously estimated costs of optimizing SCR operation, optimizing SNCR operation, and installing/upgrading combustion controls (see section 4.3.3). As a result of this modeling approach, the dispatch decisions made within the model do not take into consideration the additional operating costs associated with these three types of compliance strategies (the operating costs of the units on which these strategies are imposed do not reflect the additional costs of these strategies). The effect of changes in facility and system-wide emissions from these changes in operating costs are also not accounted for in the spatial fields for the regulatory alternatives described in Chapter 3. These additional costs and their influence on projected changes in emissions and the level and location of ozone and $PM_{2.5}$ concentration patterns from the regulatory alternatives are relatively minor, and do not have a significant impact on the overall finding that the economic impacts of this rule are minimal.

Additionally, the modeling includes two emission reduction strategies that are exogenously imposed where applicable: turning on idled SCRs and SNCRs (Revised CSAPR Update and more-stringent alternative). While these strategies are exogenously imposed, the costs and emissions reductions are estimated within IPM. Since the costs of these strategies are accounted for within the model, they are able to influence the projected behavior of the EGUs within the model.

The annualized cost of the final rule, as quantified here, is EPA's best assessment of the cost of implementing the rule. These costs are generated from rigorous economic modeling of changes in the power sector due to implementation of the Revised CSAPR Update.

4.7 References

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CHAPTER 5: BENEFITS

Overview

This final action to revise the Cross-State Air Pollution Rule (CSAPR) Update reduces the emissions of nitrogen oxides (NO_X) transported from states that contribute significantly to nonattainment or interfere with maintenance of the 2008 ozone National Ambient Air Quality Standard (NAAQS) in downwind states. Implementing the Final Revised CSAPR Update is expected to reduce emissions of NO_X which will in turn reduce ozone and fine particle ($PM_{2.5}$) concentrations; the rule will also reduce carbon dioxide (CO_2) emissions. This chapter reports the estimated monetized health benefits from reducing concentrations of ozone and $PM_{2.5}$ and global climate benefits associated with emission reductions for the three regulatory control alternatives across several discount rates.

This chapter describes the methods used to estimate health benefits from reducing concentrations of ozone and $PM_{2.5}$. While the steps to performing an air pollution benefits analysis remains unchanged, both the data used to quantify each health endpoint, and the endpoints quantified, have been updated to reflect more recent scientific evidence. EPA committed to the update in the proposal Revised CASPR Update RIA; however, the timing of the final rule has prevented the peer review of the updated approach prior to EPA issuing this final RIA. Nevertheless, this update uses information from the recent $PM_{2.5}$ and ozone ISAs (U.S. EPA, 2019a, U.S. EPA, 2020b); these ISAs were reviewed by CASAC and the public. These updates are summarized below and detailed in a technical support document (TSD) for the Final Revised CSAPR for the 2008 Ozone NAAQS Update titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*. The chapter also describes the methods used to estimate the climate benefits from reductions of CO_2 emissions. Data, resource, and methodological limitations prevent EPA from monetizing health benefits of reducing direct exposure to NO_2, ecosystem effects and visibility impairment as well as benefits from reductions in other pollutants, such as hazardous air pollutants (HAP). We qualitatively discuss these unquantified benefits in this chapter.

5.1 Estimated Human Health Benefits

The final rule is expected to reduce ozone season and annual NO_X emissions. In the presence of sunlight, NO_X and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions generally reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local levels of VOCs. The final rule would also reduce emissions of NO_X throughout the year. Because NO_X is also a precursor to formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects.[1] Reducing emissions of NO_X would also reduce ambient exposure to NO_2 and its associated health effects, though we do not quantify these effects due to lack of data.

In the proposed Revised CSAPR Update regulatory impact analysis (RIA) EPA committed to updating its approach for quantifying the benefits of changes in $PM_{2.5}$ and ozone in this final Revised CSAPR Update RIA (U.S. EPA 2020c). The updated approach incorporates evidence reported in the recently completed $PM_{2.5}$ and Ozone ISAs and accounts for recommendations from the Science Advisory Board (U.S. EPA 2019, U.S. EPA 2020b, U.S. EPA-SAB 2019, U.S. EPA-SAB 2020). When updating each health endpoint EPA considered: (1) the extent to which the science supports the existence of a causal relationship between that pollutant and the adverse effect; (2) whether suitable epidemiologic studies exist to support quantifying health impacts; (3) and whether robust economic approaches are available for estimating the value of the impact of reducing human exposure to the pollutant. Our approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized below. Detailed descriptions of these updates are available in the TSD for the Final Revised Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Update titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*.

EPA followed a five-step approach for updating its methodology for quantifying and monetizing ozone and $PM_{2.5}$ attributable health endpoints:

[1] This RIA does not quantify $PM_{2.5}$-related benefits associated with direct $PM_{2.5}$ and SO_2 emission reductions. As discussed in Chapter 4, EPA does not estimate significant direct $PM_{2.5}$ and SO_2 emission reductions as a result of this rule.

1. *Establish criteria for identifying studies and risk estimates most appropriate to inform a $PM_{2.5}$ and O_3 benefit analysis for an RIA.* Study criteria, such as study design, location, population characteristics, and other attributes, were used to identify the most suitable estimates. This step precedes health endpoint identification to ensure impartial health endpoint identification and prevent identification of non-quantifiable endpoints.
2. *Identify pollutant-attributable health effects for which the ISA reports strong evidence and that may be quantified in a benefits assessment.* EPA considered new evidence reported in the recent ISAs (U.S. EPA, 2019a, U.S. EPA, 2020b) and clinically significant outcomes (e.g. premature mortality and hospital admissions) for which endpoint-specific baseline incidence data is available. While ISAs form casual determinations for broad endpoint categories (e.g., respiratory effects), which are generally preferred over specific health endpoints (e.g., hay fever symptoms) for comprehensive benefits assessments, they do not make causal determinations for each specific health endpoints. Instead, the ISAs provide information on the strength and consistency of the evidence supporting more specific endpoints within each broad category. The strength and consistency of evidence supporting relationships with specific health endpoints, together with the broad category causality determinations, are used when identifying specific health endpoints for inclusion in benefits assessments. New ISA evidence was considered sufficient for inclusion in the benefits assessment if the ISA determine the broad heath endpoint category was causally related to pollutant exposure (TSD section 2.2.1.1), the ISA determined that the specific health endpoint is a biologically plausible health effect of exposure (TSD section 2.2.1.2 of TSD), and the ISA found strong and consistent support relating the specific health endpoint with pollutant exposure (TSD section 2.3).
3. *Collect baseline incidence and prevalence estimates and demographic information*. EPA develops either daily or annual baseline incidence and prevalence rates at the most geographically- and age-specific levels feasible for each health endpoint assessed. EPA uses population projections based on economic forecasting models developed by Woods and Poole, Inc. (Woods & Poole, 2015). The Woods and Poole (WP) database contains county-level projections of population by age, sex, and race out to 2050, relative to a baseline using the 2010 Decennial Census.

4. *Develop economic unit values*. To directly compare benefits estimates associated with a rulemaking to cost estimates, the number of instances of each air pollution-attributable health impact must be converted to a monetary value. This requires a valuation estimate for each unique health endpoint, and potentially also discounting if the benefits are expected to accrue over more than a single year. EPA develops valuation estimates at the most age-refined level feasible for each health endpoint assessed.
5. *Characterize uncertainty associated with quantified benefits estimates.* Building on EPA's current methods for characterizing uncertainty, these approaches will include, among others, reporting confidence intervals calculated from risk estimates and separate quantification using multiple studies and risk estimates for particularly influential endpoints (e.g., mortality risk), and approaches for aggregating and representing the results of multiple studies evaluating a particular health endpoint.[2]

The *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD provides a full discussion of the Agency's updated approach for quantifying the number and value of estimated air pollution-related impacts. In this document the reader can find the rationale for selecting health endpoints to quantify; the demographic, health and economic data used; modeling assumptions; and our techniques for quantifying uncertainty.[3]

Implementing the final rule will affect the distribution of ozone and $PM_{2.5}$ concentrations in much of the U.S.; this includes locations both meeting and exceeding the NAAQS for ozone and PM. This RIA estimates avoided ozone- and $PM_{2.5}$-related health impacts that are distinct from those reported in the RIAs for both NAAQS (U.S. EPA 2012, 2015e). The ozone and $PM_{2.5}$ NAAQS RIAs hypothesize, but do not predict, the benefits and costs of strategies that States may choose to enact when implementing a revised NAAQS; these costs and benefits are illustrative and cannot be added to the costs and benefits of policies that prescribe specific emission control measures. This RIA estimates the benefits (and costs) of specific emissions control measures.

[2] We consider study quality, inter-study heterogeneity, and redundancy where epidemiologic risk estimates are combined or aggregated.
[3] Updated information has been incorporated into BenMAP-CE version 1.5.7.0, which will be publicly released by March 15, 2021.

We project how the levels of ozone and $PM_{2.5}$ may increase and decrease over the U.S. compared to the baseline. Some portion of the air quality and health benefits from the regulatory control alternatives will occur in areas not attaining the Ozone or $PM_{2.5}$ NAAQS. However, we do not simulate how states would account for this rule when complying with the NAAQS; this affects the estimated benefits (and costs) of the final rule and more and less stringent alternatives, which introduces uncertainty in the estimated benefits (and costs).

5.2.1 Health Impact Assessment for Ozone and $PM_{2.5}$

The benefits analysis presented in this chapter incorporates an array of science-policy and technical changes that the Agency has adopted since the previous reviews of the $PM_{2.5}$ standards in 2012 and the ozone standards in 2015, as well as since publishing the most recent major benefits analysis, documented in the benefits chapter of the RIA accompanying the proposed Revised CSAPR Update (U.S. EPA, 2020c). Below we note aspects of this analysis that differ from the Revised CSAPR Update proposal RIA. The rationale for these choices is detailed in the *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD:

1. Updated mortality studies and endpoints

   a. *Removed short-term all-cause ozone mortality endpoint and include respiratory ozone mortality.* The recent ozone ISA downgraded the causal determination between short-term ozone exposure and total mortality to "suggestive of, but not sufficient to infer, a causal relationship." As the 2020 ozone ISA retained the long-term ozone respiratory determination of "likely to be causal" we selected a risk estimate for this health endpoint from Turner et al. (2016). As such, respiratory ozone mortality endpoints were added (for short-term), and all-cause (or non-accidental) ozone mortality based upon (Smith et al. 2009) was removed. Qualitatively, the updated risk estimate of long-term ozone exposure-attributable respiratory mortality is larger than the Jerrett et al. (2009) estimate used previously. The two identified risk estimates of short-term ozone exposure -attributable respiratory mortality are not directly comparable to previous estimates of short-term exposure-related total/nonaccidental mortality as the different baseline incidence rates associated with each health endpoint also impact the benefits estimates.

b. *Removed the Harvard Six Cities (HSC) $PM_{2.5}$ mortality study*. Several recent epidemiological analyses of $PM_{2.5}$ and total mortality have increased geographical coverage and better characterize recent exposures as compared to the HCS cohort, so Lepeule et al. (2012) was removed.

c. *Incorporated newer long-term exposure $PM_{2.5}$ mortality studies.* We selected risk estimates from an extended analysis of the American Cancer Society (ACS) cohort analysis Turner et al. (2016) and a recent analysis of the Medicare cohort Di et al. (2017). Compared to the ACS study it replaces (Krewski et al. 2009), Turner et al. (2016) incorporates additional years of cohort follow-up and $PM_{2.5}$ air quality data. We also selected a risk estimate from an analysis of the Medicare cohort (Di et al. 2017), which incorporates a large and representative population, improved exposure assessment methods, and recent air quality information. Qualitatively, the two updated risk estimates are both very similar to the previous Krewski et al. (2009) estimate of mortality derived from the ACS cohort.

2. <u>Updated morbidity endpoints</u>. Incorporated new $PM_{2.5}$ and ozone morbidity endpoints. Upon careful evaluation of this new literature identified in the 2019 PM ISA and 2020 Ozone ISA (U.S. EPA, 2019, U.S. EPA, 2020) we added several new morbidity endpoints to our health impact assessment. New endpoints include the association between exposure and cardiovascular emergency department visits, lung cancer, allergic rhinitis (hay fever), asthma onset, Alzheimer's disease hospital admissions, Parkinson's disease hospital admission, and stroke.

3. <u>Incorporated new demographic data</u>. We updated the baseline population demographic data to reflect an updated projection of the 2010 Census data to future years (Woods & Poole, 2015). These data replace the earlier demographic projection data from Woods & Poole (2015).

4. <u>Incorporated new valuations estimates.</u> Economic valuation estimates were developed or identified for new morbidity health endpoints.

5. <u>Incorporated updated uncertainty analyses</u>. Advancements in epidemiology allow for updated uncertainty and sensitivity analyses, such as those comparing different techniques for estimating exposure, are included in the TSD. Where possible, we quantitatively assess

uncertainties associated with $PM_{2.5}$ benefit estimates (TSD section 6.1), ozone benefit estimates (TSD section 6.2), baseline incidence rate estimates (TSD section 6.3), and economic valuation estimates (TSD section 6.4). We focus on input parameters that are likely to most greatly influence the size of the estimated health impacts, such as those related to mortality impacts. When quantitative analysis is not possible, we characterize the sensitivity of the results to alternative plausible input parameters when feasible.

6. Replaced medical charges with medical costs, when possible. Based on newly available data from the Healthcare Cost and Utilization Project (HCUP) National Inpatient Sample (NIS), we replaced several hospital admissions charge estimates with cost estimates, allowing for a more appropriate estimate of the costs borne by patients and insurance companies.[4] Using the hospital admission cost-to-charge ratio, we also developed emergency department cost estimates, which replaced emergency department charge estimates.

Estimating the health benefits of reductions in $PM_{2.5}$ and O_3 exposure begins with estimating the change in exposure for each individual and then estimating the change in each individual's risks for those health outcomes affected by exposure. The benefit of the reduction in each health risk is based on the exposed individual's WTP for the risk change, assuming that each outcome is independent of one another. The greater the magnitude of the risk reduction from a given change in concentration, the greater the individual's WTP, all else equal. The social benefit of the change in health risks equals the sum of the individual WTP estimates across all of the affected individuals.[5] We conduct this analysis by adapting primary research—specifically, air pollution epidemiology studies and economic value studies—from similar contexts. This approach is sometimes referred to as "benefits transfer." Below we describe the procedure we follow for: (1) selecting air pollution health endpoints to quantify; (2) calculating counts of air pollution effects using a health impact function; (3) specifying the health impact function with concentration-response parameters drawn from the epidemiological literature.

[4] Willingness-to-pay (WTP) is the preferred welfare estimate for avoiding the risk of health effects. However, for more endpoints WTP estimates are not available and therefore cost-of-illness (COI) estimates are used as a proxy. Usually COI estimates are an underestimate of WTP. Cost estimates are a better estimate of COI than charge estimates as they reflect the actual cost to society of providing care for these endpoints.

[5] This RIA also reports the change in the sum of the risk, or the change in the total incidence, of a health outcome across the population. If the benefit per unit of risk is invariant across individuals, the total expected change in the incidence of the health outcome across the population can be multiplied by the benefit per unit of risk to estimate the social benefit of the total expected change in the incidence of the health outcome.

5.2.1.1 Selecting Air Pollution Health Endpoints to Quantify

As a first step in quantifying ozone and $PM_{2.5}$-related human health impacts, the Agency consults the Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Ozone ISA) (U.S. EPA 2020b) and the Integrated Science Assessment for Particulate Matter (PM ISA) (U.S. EPA 2019a). These two documents synthesize the toxicological, clinical and epidemiological evidence to determine whether each pollutant is causally related to an array of adverse human health outcomes associated with either acute (i.e., hours or days-long) or chronic (i.e. years-long) exposure; for each outcome, the ISA reports this relationship to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship or not likely to be a causal relationship. The Agency estimates the incidence of air pollution effects for those health endpoints above where the ISA classified as either causal or likely-to-be-causal. In brief, the ISA for ozone found short-term (less than one month) exposures to ozone to be causally related to respiratory effects, a "likely to be causal" relationship with metabolic effects and a "suggestive of, but not sufficient to infer, a causal relationship" for central nervous system effects, cardiovascular effects, and total mortality. The ISA reported that long-term exposures (one month or longer) to ozone are "likely to be causal" for respiratory effects including respiratory mortality, and a "suggestive of, but not sufficient to infer, a causal relationship" for cardiovascular effects, reproductive effects, central nervous system effects, metabolic effects, and total mortality. The PM ISA found short-term exposure to $PM_{2.5}$ to be causally related to cardiovascular effects and mortality (i.e., premature death), respiratory effects as likely-to-be-causally related, and a suggestive relationship for metabolic effects and nervous system effects. The ISA identified cardiovascular effects and total mortality as being causally related to long-term exposure to $PM_{2.5}$. A likely-to-be-causal relationship was determined between long-term $PM_{2.5}$ exposures and respiratory effects, nervous system effects, and cancer effects were; and the evidence was suggestive of a causal relationship for male and female reproduction and fertility effects, pregnancy and birth outcomes, and metabolic effects. Table 5-1 reports the effects we quantified and those we did not quantify in this RIA. The list of benefit categories not quantified is not exhaustive. And, among the effects quantified, it might not have been possible to quantify completely either the full range of human health impacts or economic values. The table below omits health effects associated with NO_2 exposure, and any welfare effects such as acidification and nutrient enrichment; these effects are described in the Ozone and PM NAAQS RIA (U.S. EPA 2015e, 2012) and summarized later in this appendix.

Consistent with economic theory, the willingness to pay (WTP) for reductions in exposure to environmental hazard will depend on the expected impact of those reductions on human health and other outcomes. All else equal, WTP is expected to be higher when there is stronger evidence of a causal relationship between exposure to the contaminant and changes in a health outcome (McGartland et al., 2017). For example, in the case where there is no evidence of a potential relationship the WTP would be expected to be zero and the effect should be excluded from the analysis. Alternatively, when there is some evidence of a relationship between exposure and the health outcome, but that evidence is insufficient to definitively conclude that there is a causal relationship, individuals may have a positive WTP for a reduction in exposure to that hazard (U.S. EPA-SAB 2020b, Kivi and Shogren, 2010). Lastly, the WTP for reductions in exposure to pollutants with strong evidence of a relationship between exposure and effect are likely positive and larger than for endpoints where evidence is weak, all else equal. Unfortunately, the economic literature currently lacks a settled approach for accounting for how WTP may vary with uncertainty about causal relationships.

Given these challenges, the Agency draws its assessment of the strength of evidence on the relationship between exposure to $PM_{2.5}$ or O_3 and potential health endpoints from the ISAs that are developed for the NAAQS process as discussed above. The focus on categories identified as having a "causal" or "likely to be causal" relationship with the pollutant of interest is to estimate the pollutant-attributable human health benefits in which we are most confident.[6] All else equal, this approach may underestimate the benefits of $PM_{2.5}$ and O_3 exposure reductions as individuals may be WTP to avoid specific risks where the evidence is insufficient to conclude they are "likely to be caus[ed]" by exposure to these pollutants.[7] At the same time, WTP may be lower for those health outcomes for which causality has not been definitively established. This approach treats relationships with ISA causality determinations of "likely to be causal" as if they were known to be causal, and therefore benefits could be overestimated.

[6] This decision criterion for selecting health effects to quantify and monetize $PM_{2.5}$ and O_3 is only applicable to estimating the benefits of exposure of these two pollutants. This decision criterion may not be applicable or suitable for quantifying and monetizing health and ecological effects of other pollutants.

[7] EPA includes risk estimates for an example health endpoint with a causality determination of "suggestive, but not sufficient to infer" that is associated with a potentially substantial economic value in the quantitative uncertainty characterization (*Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD section 6.2.3).

Table 5-1. Health Effects of Ambient Ozone and $PM_{2.5}$

Category	Effect	Effect Quantified	Effect Monetized	More Information
Premature mortality from exposure to $PM_{2.5}$	Adult premature mortality from long-term exposure (age 65-99 or age 30-99)	✓	✓	PM ISA
	Infant mortality (age <1)	✓	✓	PM ISA
Nonfatal morbidity from exposure to $PM_{2.5}$	Heart attacks (age > 18)	✓	✓[1]	PM ISA
	Hospital admissions—cardiovascular (ages 65-99)	✓	✓	PM ISA
	Emergency department visits— cardiovascular (age 0-99)	✓	✓	PM ISA
	Hospital admissions—respiratory (ages 0-18 and 65-99)	✓	✓	PM ISA
	Emergency room visits—respiratory (all ages)	✓	✓	PM ISA
	Cardiac arrest (ages 0-99; excludes initial hospital and/or emergency department visits)	✓	✓[1]	PM ISA
	Stroke (ages 65-99)	✓	✓[1]	PM ISA
	Asthma onset (ages 0-17)	✓	✓	PM ISA
	Asthma symptoms/exacerbation (6-17)	✓	✓	PM ISA
	Lung cancer (ages 30-99)	✓	✓	PM ISA
	Allergic rhinitis (hay fever) symptoms (ages 3-17)	✓	✓	PM ISA
	Lost work days (age 18-65)	✓	✓	PM ISA
	Minor restricted-activity days (age 18-65)	✓	✓	PM ISA
	Hospital admissions—Alzheimer's disease (ages 65-99)	✓	✓	PM ISA
	Hospital admissions—Parkinson's disease (ages 65-99)	✓	✓	PM ISA
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[2]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[2]
	Other nervous system effects (e.g., autism, cognitive decline, dementia)	—	—	PM ISA[2]
	Metabolic effects (e.g., diabetes)	—	—	PM ISA[2]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)	—	—	PM ISA[2]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[2]
Mortality from exposure to ozone	Premature respiratory mortality from short-term exposure (0-99)	✓	✓	Ozone ISA
	Premature respiratory mortality from long-term exposure (age 30–99)	✓	✓	Ozone ISA
Nonfatal morbidity from exposure to ozone	Hospital admissions—respiratory (ages 65-99)	✓	✓	Ozone ISA
	Emergency department visits—respiratory (ages 0-99)	✓	✓	Ozone ISA
	Asthma onset (0-17)	✓	✓	Ozone ISA
	Asthma symptoms/exacerbation (asthmatics age 5-17)	✓	✓	Ozone ISA
	Allergic rhinitis (hay fever) symptoms (ages 3-17)	✓	✓	Ozone ISA
	Minor restricted-activity days (age 18–65)	✓	✓	Ozone ISA
	School absence days (age 5–17)	✓	✓	Ozone ISA
	Decreased outdoor worker productivity (age 18–65)	—	—	Ozone ISA[2]
	Metabolic effects (e.g., diabetes)	—	—	Ozone ISA[2]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[2]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[2]

Reproductive and developmental effects	—	—	Ozone ISA[2]

[1]Valuation estimate excludes initial hospital and/or emergency department visits.
[2] Not quantified due to data availability limitations and/or because current evidence is only suggestive of causality.

5.2.1.2 Calculating Counts of Air Pollution Effects Using the Health Impact Function

We use BenMAP-CE to quantify individual risk and counts of estimated premature deaths and illnesses attributable to photochemical modeled changes in summer season average ozone concentrations for the year 2021, and summer season average ozone concentrations and annual mean $PM_{2.5}$ for the year 2024 using a health impact function. A health impact function combines information regarding the: concentration-response relationship between air quality changes and the risk of a given adverse outcome; population exposed to the air quality change; baseline rate of death or disease in that population; and, air pollution concentration to which the population is exposed.

The following provides an example of a health impact function, in this case for $PM_{2.5}$ mortality risk. We estimate counts of $PM_{2.5}$-related total deaths (y_{ij}) during each year i (i=1,…,I where I is the total number of years analyzed) among adults aged 30 and older (a) in each county in the contiguous U.S. j (j=1,…,J where J is the total number of counties) as

$$y_{ij} = \Sigma_a \, y_{ija}$$
$$y_{ija} = mo_{ija} \times (e^{\beta \cdot \Delta C_{ij}} - 1) \times P_{ija}, \quad \text{Eq[1]}$$

where mo_{ija} is the baseline all-cause mortality rate for adults aged a=30-99 in county j in year i stratified in 10-year age groups, β is the risk coefficient for all-cause mortality for adults associated with annual average $PM_{2.5}$ exposure, C_{ij} is the annual mean $PM_{2.5}$ concentration in county j in year i, and P_{ija} is the number of county adult residents aged a=30-99 in county j in year i stratified into 5-year age groups.[8]

The BenMAP-CE tool is pre-loaded with projected population from the Woods & Poole company; cause-specific and age-stratified death rates from the Centers for Disease Control and

[8] In this illustrative example, the air quality is resolved at the county level. For this RIA, we simulate air quality concentrations at 12km by 12km grids. The BenMAP-CE tool assigns the rates of baseline death and disease stored at the county level to the 12km by 12km grid cells using an area-weighted algorithm. This approach is described in greater detail in the appendices to the BenMAP-CE user manual.

Prevention, projected to future years; recent-year baseline rates of hospital admissions, emergency department visits and other morbidity outcomes from the Healthcare Cost and Utilization Program and other sources; concentration-response parameters from the published epidemiologic literature cited in the ISAs for fine particles and ground-level ozone; and, cost of illness or WTP unit values for each endpoint. Ozone and $PM_{2.5}$ concentrations are taken from the air pollution spatial surfaces described in Chapter 3.

5.2.1.3 Quantifying Ozone-Attributable Premature Mortality

In 2008, the National Academies of Science (NRC 2008) issued a series of recommendations to EPA regarding the procedure for quantifying and valuing ozone-related mortality due to short-term exposures. Chief among these was that "…short-term exposure to ambient ozone is likely to contribute to premature deaths" and the committee recommended that "ozone-related mortality be included in future estimates of the health benefits of reducing ozone exposures…" The NAS also recommended that "…the greatest emphasis be placed on the multicity and [National Mortality and Morbidity Air Pollution Studies (NMMAPS)] …studies without exclusion of the meta-analyses" (NRC 2008). Prior to the 2015 Ozone NAAQS RIA, the Agency estimated ozone-attributable premature deaths using an NMMAPS-based analysis of total mortality (Bell et al. 2004), two multi-city studies of cardiopulmonary and total mortality (Huang et al. 2004; Schwartz 2005) and effect estimates from three meta-analyses of non-accidental mortality (Bell et al. 2005; Ito et al. 2005; Levy et al. 2005). Beginning with the 2015 Ozone NAAQS RIA, the Agency began quantifying ozone-attributable premature deaths using two newer multi-city studies of non-accidental mortality (Smith et al. 2009; Zanobetti and Schwartz 2008) and one long-term cohort study of respiratory mortality (Jerrett et al. 2009). The 2020 Ozone ISA included changes to the causality relationship determinations between short-term exposures and total mortality, as well as including more recent epidemiologic analyses of long-term exposure effects on respiratory mortality (U.E. EPA, 2020b). In this RIA, as described in the corresponding TSD, two estimates of ozone-attributable respiratory deaths from short-term exposures are estimated using the risk estimate parameters from Zanobetti et al. (2008) and Katsouyanni et al. (2009). Ozone-attributable respiratory deaths from long-term exposures are estimated using Turner et al. (2016). Due to time and resource limitations, we were unable to reflect the warm season defined by Zanobetti et al. (2008) as June-August. Instead, we apply this risk estimate to our standard warm season of May-September.

5.2.1.4 Quantifying $PM_{2.5}$-Attributable Premature Mortality

When quantifying PM-attributable cases of adult mortality, we use the effect coefficients from two epidemiology studies examining two large population cohorts: the American Cancer Society cohort (Turner et al. 2016) and the Medicare cohort (Di et al. 2017). The Integrated Science Assessment for Particulate Matter (PM ISA) (U.S. EPA 2019) concluded that the analyses of the ACS and Medicare cohorts provide strong evidence of an association between long-term $PM_{2.5}$ exposure and premature mortality with support from additional cohort studies. There are distinct attributes of both the ACS and Medicare cohort studies that make them well-suited to being used in a PM benefits assessment and so here we present $PM_{2.5}$ related effects derived using relative risk estimates from both cohorts.

The PM ISA, which was reviewed by the Clean Air Scientific Advisory Committee of EPA's Science Advisory Board (SAB-CASAC) (EPA-SAB 2020a), concluded that there is a causal relationship between mortality and both long-term and short-term exposure to $PM_{2.5}$ based on the entire body of scientific evidence. The PM ISA also concluded that the scientific literature supports the use of a no-threshold log-linear model to portray the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response relationship. The 2019 PM ISA, which informed the setting of the 2020 PM NAAQS, reviewed available studies that examined the potential for a population-level threshold to exist in the concentration-response relationship. Based on such studies, the ISA concluded that "evidence from recent studies reduce uncertainties related to potential copollutant confounding and continues to provide strong support for a linear, no-threshold concentration-response relationship" (U.S. EPA 2019) (section 11.2.7). Consistent with this evidence, the Agency historically has estimated health impacts above and below the prevailing NAAQS (U.S. EPA 2010c, 2010d, 2011c, 2011d, 2012, 2013b, 2014a, 2014b, 2014c, 2015a, 2015b, 2015c, 2015d, 2015e, 2016b).

Following this approach, we report the estimated $PM_{2.5}$-related benefits (in terms of both health impacts and monetized values) calculated using a log-linear concentration-response function that quantifies risk from the full range of simulated $PM_{2.5}$ exposures (NRC 2002; U.S. EPA 2009). When setting the 2020 PM NAAQS, the EPA noted that "…an important consideration in characterizing the potential for additional public health improvements associated with changes in $PM_{2.5}$ exposure is whether concentration- response relationships are linear across the range of concentrations or if nonlinear relationships exist along any part of this range. Several recent studies examine this issue, and continue to provide evidence of linear, no-threshold relationships between long-term $PM_{2.5}$ exposures and all-cause and cause- specific mortality (U.S. EPA, 2019, section 11.2.4). However, interpreting the shapes of these relationships, particularly at $PM_{2.5}$ concentrations near the lower end of the air quality distribution, can be complicated by relatively low data density in the lower concentration range, the possible influence of exposure measurement error, and variability among individuals with respect to air pollution health effects (85 FR 82696, December 18, 2020)." Hence, we are most confident in the size of the risks estimated from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.

Hence, we are most confident in the size of the risks estimated from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.

To give readers insight to the level of uncertainty in the estimated $PM_{2.5}$ mortality benefits at lower ambient concentrations, we report the estimated PM benefits as a distribution, identifying points along this distribution corresponding to the Lowest Reported Levels of each long-term exposure mortality study and the PM NAAQS (Figure 5-2). In addition to adult mortality discussed above, we use effect coefficients from a multi-city study to estimate PM-related infant mortality (Woodruff et al. 2008).

5.2.2 Economic Valuation Methodology for Health Benefits

We next quantify the economic value of the ozone and $PM_{2.5}$-related deaths and illnesses estimated above. Changes in ambient concentrations of air pollution generally yield small changes in the risk of future adverse health effects for a large number of people. Therefore, the appropriate economic measure is WTP for changes in risk of a health effect. For some health effects, such as hospital admissions, WTP estimates are not generally available, so we use the cost of treating or mitigating the effect. These cost-of-illness (COI) estimates are typically a lower bound estimate of the true value of reducing the risk of a health effect because they reflect the direct expenditures related to treatment, but not the value of avoided pain and suffering The unit values applied in this analysis are provided in Table 21 of the *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD.

The estimated value of avoided premature deaths account for over 95 percent of monetized ozone-related benefits and over 98 percent of monetized $PM_{2.5}$-related benefits of this rule. The economics literature concerning the appropriate method for valuing reductions in premature mortality risk is still developing. The value for the projected reduction in the risk of premature mortality is the subject of continuing discussion within the economics and public policy analysis community. Following the advice of the SAB's Environmental Economics Advisory Committee (SAB-EEAC), EPA currently uses the value of statistical life (VSL) approach in calculating estimates of mortality benefits, because we believe this calculation provides the most reasonable single estimate of an individual's willingness to trade off money for changes in the risk of death (U.S. EPA-SAB 2000a). The VSL approach is a summary measure for the value of small changes in the risk of death experienced by a large number of people.

EPA continues work to update its guidance on valuing mortality risk reductions, and the Agency consulted several times with the SAB-EEAC on this issue. Until updated guidance is available, the Agency determined that a single, peer-reviewed estimate applied consistently, best reflects the SAB-EEAC advice it has received. Therefore, EPA applies the VSL that was vetted and endorsed by the SAB in the *Guidelines for Preparing Economic Analyses* (U.S. EPA 2016a) while the Agency continues its efforts to update its guidance on this issue. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is $4.8 million (1990$). We then adjust this VSL to account for the currency year and to account for income growth from 1990 to the analysis year. Specifically, the VSLs applied in this analysis in 2016$ after adjusting for income growth is $10.5 million for 2021 and $10.7 million for 2024.

The Agency is committed to using scientifically sound, appropriately reviewed evidence in valuing changes in the risk of premature death and continues to engage with the SAB to identify scientifically sound approaches to update its mortality risk valuation estimates. In 2016, the Agency proposed new meta-analytic approaches for updating its estimates (U.S. EPA-SAB 2017), which were subsequently reviewed by the SAB-EEAC. EPA is taking the SAB's formal recommendations under advisement.

In valuing $PM_{2.5}$-related premature mortality, we discount the value of premature mortality occurring in future years using rates of 3 percent and 7 percent (U.S. Office of Management and Budget 2003). We assume that there is a multi-year "cessation" lag between changes in PM exposures and the total realization of changes in health effects. Although the structure of the lag is uncertain, EPA follows the advice of the SAB-HES to use a segmented lag structure that assumes 30 percent of premature deaths are reduced in the first year, 50 percent over years 2 to 5, and 20 percent over the years 6 to 20 after the reduction in $PM_{2.5}$ (U.S. EPA-SAB 2004). Changes in the cessation lag assumptions do not change the total number of estimated deaths but rather the timing of those deaths.

Because short-term ozone-related premature mortality occurs within the analysis year, the estimated ozone-related benefits are identical for all discount rates. When valuing changes in ozone-attributable deaths using the Turner et al. (2016) study, we follow advice provided by the Health Effects Subcommittee of the SAB, which found that "…there is no evidence in the literature to support a different cessation lag between ozone and particulate matter. The HES therefore recommends using the same cessation lag structure and assumptions as for particulate matter when utilizing cohort mortality evidence for ozone" (U.S. EPA-SAB 2010).

These estimated health benefits do not account for the influence of future changes in the climate on ambient concentrations of pollutants (USGCRP 2016). For example, recent research suggests that future changes to climate may create conditions more conducive to forming ozone;

the influence of changes in the climate on $PM_{2.5}$ concentrations are less clear (Fann et al. 2015). The estimated health benefits also do not consider the potential for climate-induced changes in temperature to modify the relationship between ozone and the risk of premature death (Jhun et al. 2014; Ren et al. 2008a, 2008b).

5.2.3 Characterizing Uncertainty in the Estimated Benefits

This analysis includes many data sources as inputs that are each subject to uncertainty. Input parameters include projected emission inventories, projected compliance methods and emissions from the electricity sector analysis, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). When compounded, even small uncertainties can greatly influence the size of the total quantified benefits.

Our estimate of the total monetized $PM_{2.5}$ and ozone-attributable benefits is based on EPA's interpretation of the best available scientific literature and methods and supported by the SAB-HES and the National Academies of Science (NRC 2002). Below are key assumptions underlying the estimates for $PM_{2.5}$-related premature mortality, followed by key uncertainties associated with estimating the number and value of ozone-related premature deaths.

We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, the PM ISA concluded that "many constituents of $PM_{2.5}$ can be linked with multiple health effects, and the evidence is not yet sufficient to allow differentiation of those constituents or sources that are more closely related to specific outcomes" (U.S. EPA 2009).

As noted above, we assume that the health impact function for fine particles is log-linear without a threshold. Thus, the estimates include health benefits from reducing fine particles in areas with different concentrations of $PM_{2.5}$, including both areas that do not meet the fine particle standard and those areas that are in attainment and reflect the full distribution of $PM_{2.5}$ air quality simulated above.

Also, as noted above, we assume that there is a "cessation" lag between the change in PM exposures and the total realization of changes in mortality effects. Specifically, we assume that some of the incidences of premature mortality related to $PM_{2.5}$ exposures occur in a distributed fashion over the 20 years following exposure based on the advice of the SAB-HES (U.S. EPA-SAB 2004), which affects the valuation of mortality benefits at different discount rates. The above assumptions are subject to uncertainty.

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies. There are uncertainties inherent in identifying any particular point at which our confidence in reported associations decreases appreciably, and the scientific evidence provides no clear dividing line. This relationship between the air quality data and our confidence in the estimated risk is represented below in Figure 5-.

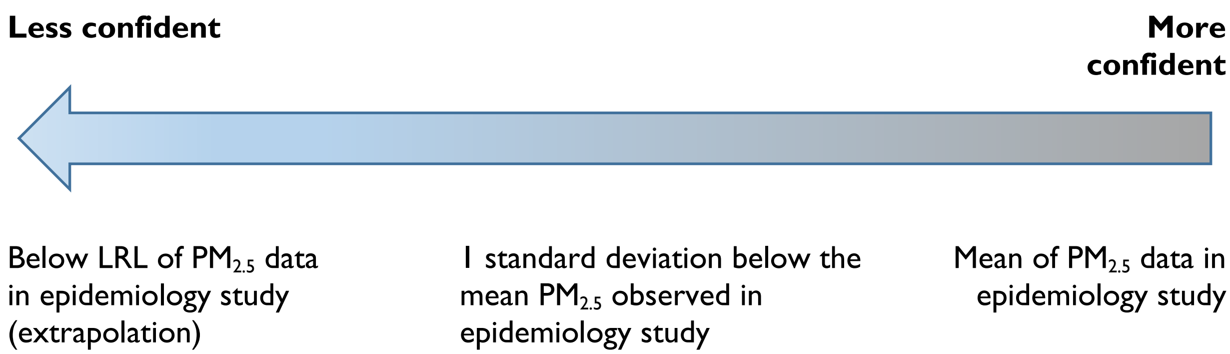

Figure 5-1. Stylized Relationship between the $PM_{2.5}$ Concentrations Considered in Epidemiology Studies and our Confidence in the Estimated PM-related Premature Deaths

In this analysis, we build upon the concentration benchmark approach (also referred to as the Lowest Reported Level (LRL) analysis) that has been featured in recent RIAs by reporting the estimated PM-related deaths according to alternative concentration cut points.

Concentration benchmark analyses allow readers to determine the portion of population exposed to annual mean $PM_{2.5}$ levels at or above different concentrations, which provides some insight into the level of uncertainty in the estimated $PM_{2.5}$ mortality benefits. EPA does not view these concentration benchmarks as concentration thresholds below which we would not quantify health benefits of air quality improvements.[9] Rather, the $PM_{2.5}$-attributable benefits estimates reported in this RIA are the most appropriate estimates because they reflect the full range of air quality concentrations associated with the emission reduction strategies being evaluated in this final rule. The 2019 PM ISA concluded that the scientific evidence collectively is sufficient to conclude that there is a causal relationship between long-term $PM_{2.5}$ exposures and mortality and that overall the studies support the use of a no-threshold log-linear model to estimate mortality attributed to long-term $PM_{2.5}$ exposure (U.S. EPA 2009).

Figure 5-2 compares the percentage of the population and PM-related deaths, to the annual mean $PM_{2.5}$ concentrations in the final policy modeling for the year 2024. The figure identifies the LRL for each of the major cohort studies and the annual mean $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$. For Turner et al. 2016, the LRL is 2.8 $\mu g/m^3$ and for Di et al. 2017, the LRL is 0.02 $\mu g/m^3$. As PM-related mortality quantified using risk estimates from the Di et al. (2017) and Turner et al. (2016) are within 5% of one another, in the interest of clarity and simplicity, we present the results estimated using the risk estimate from Turner et al. (2016) alone in Figure 5-2. Additional information on low concentration exposures in Turner et al. 2016 and Di et al. 2017 can be found in section 6.1.2.1 of the *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD. These results are sensitive to the annual mean $PM_{2.5}$ concentration the air quality model predicted in each 12km by 12km grid cell. The air quality modeling predicts $PM_{2.5}$ concentrations to be at or below the $PM_{2.5}$ NAAQS (12 $\mu g/m^3$) in nearly all locations. The photochemical modeling we employ accounts for the suite of local, state and federal policies expected to reduce $PM_{2.5}$ and $PM_{2.5}$ precursor emissions in future years, such that we project a very small number of locations exceeding the annual standard. The results should be viewed in the context of the air quality modeling technique we used to estimate $PM_{2.5}$ concentrations. We are more confident in our ability to use the air quality modeling technique described above to estimate *changes* in annual mean $PM_{2.5}$ concentrations than we are in our ability to estimate *absolute* $PM_{2.5}$ concentrations.

[9] For a summary of the scientific review statements regarding the lack of a threshold in the $PM_{2.5}$-mortality relationship, see the TSD entitled *Summary of Expert Opinions on the Existence of a Threshold in the Concentration-Response Function for $PM_{2.5}$-related Mortality* (U.S. EPA, 2010b).

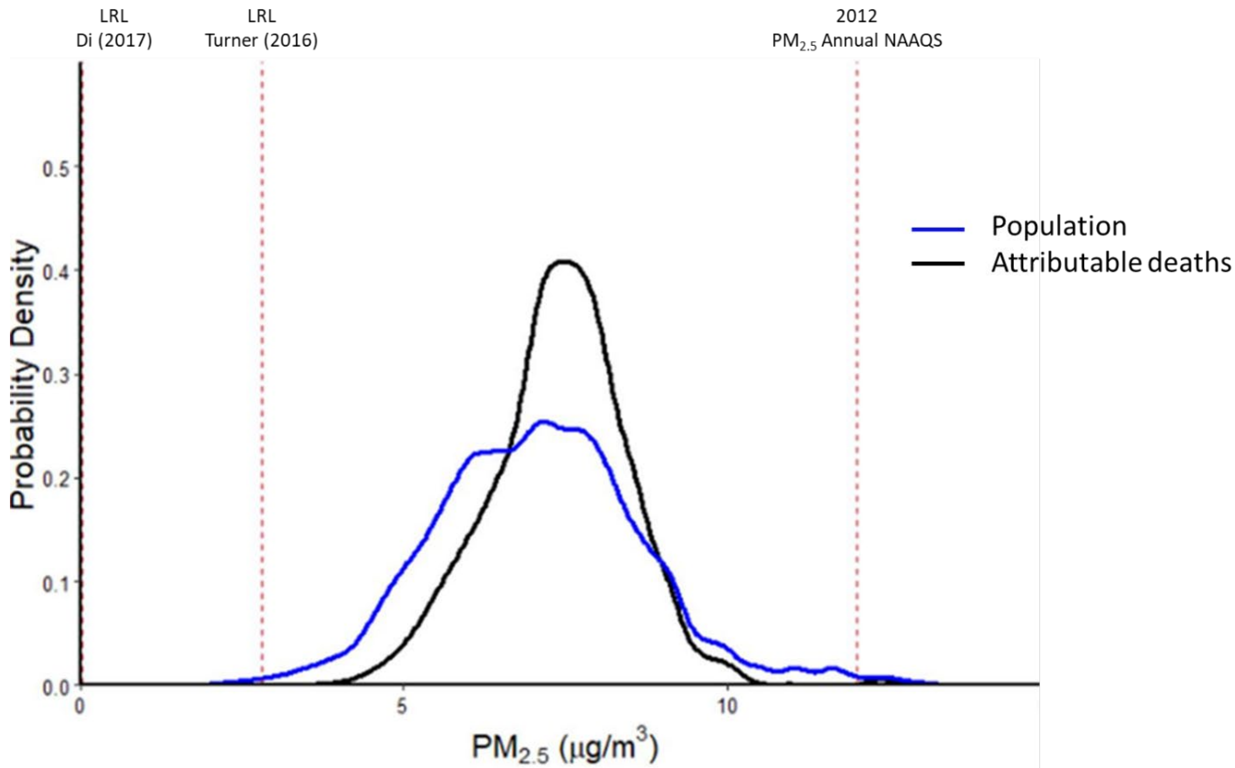

Figure 5-2. Estimated Percentage of $PM_{2.5}$-Related Deaths and Number of Individuals Exposed by Annual Mean $PM_{2.5}$ Level in 2024

The estimated number and value of avoided ozone-attributable deaths are also subject to uncertainty. When estimating the economic value of avoided premature mortality from long-term exposure to ozone, we use a 20-year segment lag (as used for $PM_{2.5}$) as there is no alternative empirical estimate of the cessation lag for long-term exposure to ozone. The 20-year segmented lag accounts for the onset of cardiovascular related mortality, an outcome which is not relevant to the long-term respiratory mortality estimated here. We use a log-linear impact function without a threshold in modeling short-term ozone-related mortality. However, we acknowledge reduced confidence in specifying the shape of the concentration-response relationship in the range of ≤ 40ppb and below (2020 Ozone ISA, section 6.2.6). Thus, the estimates include health benefits from reducing ozone in areas with varied concentrations of ozone down to the lowest modeled concentrations.

5.2.4 Estimated Number and Economic Value of Health Benefits

Below we report the estimated number of reduced premature deaths and illnesses in each year relative to the baseline along with the 95% confidence interval (Table 5-2 and Table 5-3). The number of reduced estimated deaths and illnesses from the final rule and more and less stringent alternatives are calculated from the sum of individual reduced mortality and illness risk across the population. Table 5-4 and Table 5-5 report the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95% confidence interval. In each of these tables, for each discount rate and regulatory control alternative, multiple benefits estimates are presented reflecting alternative ozone and $PM_{2.5}$ mortality risk estimates. We also report the stream of benefits from 2021 through 2040 for the final, more- and less- stringent scenarios, using the monetized sums of long-term ozone and $PM_{2.5}$ mortality and morbidity impacts (Table 5-6 and Table 5-7).[10]

[10] EPA continues to refine its approach for estimating and reporting PM-related effects at lower concentrations. The Agency acknowledges the additional uncertainty associated with effects estimated at these lower levels and seeks to develop quantitative approaches for reflecting this uncertainty in the estimated PM benefits.

Table 5-2. Estimated Avoided Ozone-Related Premature Respiratory Mortality and Illnesses for the Final and More and Less Stringent Alternatives for 2021 (95% Confidence Interval) [a,b]

		Final	More Stringent Alternative	Less Stringent Alternative
Avoided premature respiratory mortality				
Long-term exposure	Turner *et al.* (2016)[c]	190 (130 to 250)	190 (130 to 250)	18 (13 to 24)
Short-term exposure	Katsouyanni *et al.* (2009)[c,d] and Zanobetti *et al.* (2008)[d] pooled	9 (4 to 14)	9 (0 to 14)	1 (0 to 1)
	Katsouyanni *et al.* (2009)[cd]	9 (-5 to 21)	9 (-5 to 21)	1 (0 to 2)
	Zanobetti *et al.* (2008)[e]	9 (4 to 13)	9 (4 to 13)	1 (0 to 1)
Morbidity effects				
Long-term exposure	Asthma onset[e]	1,300 (1,100 to 1,500)	1,300 (1,100 to 1,500)	130 (110 to 150)
	Allergic rhinitis symptoms[g]	7,700 (4,000 to 11,000)	7,700 (4,000 to 11,000)	750 (400 to 1,100)
Short-term exposure	Hospital admissions—respiratory[d]	21 (-5 to 46)	21 (-5 to 46)	2 (-1 to 5)
	ED visits—respiratory[f]	440 (120 to 920)	440 (120 to 920)	43 (12 to 90)
	Asthma symptoms	240,000 (-30,000 to 500,000)	240,000 (-30,000 to 500,000)	24,000 (-2,900 to 49,000)
	Minor restricted-activity days[d,f]	120,000 (49,000 to 200,000)	120,000 (49,000 to 200,000)	12,000 (4,800 to 19,000)
	School absence days	91,000 (-13,000 to 190,000)	91,000 (-13,000 to 190,000)	8,900 (-1,300 to 19,000)

[a] Values rounded to two significant figures.

[b] We estimated changes in annual mean $PM_{2.5}$ and $PM_{2.5}$ -related benefits in 2024, but not 2021. As discussed in Chapter 4, in 2021, the only control measure expected to be adopted for compliance in the regulatory control alternatives analysis in this RIA is optimization of existing SCRs, and this measure will operate only during the ozone season. As discussed in Chapter 3, NOx reductions in the ozone season provide minimal $PM_{2.5}$ benefits since $PM_{2.5}$ nitrate concentrations, which result from conversion of NOx emissions to nitrate, are minimal during the warmer temperatures during the ozone season. Conversely, the conversion of nitrates to $PM_{2.5}$ is much greater in cooler (non-ozone season) months, and thus it becomes worthwhile to estimate $PM_{2.5}$ benefits from NOx reductions in those months. In 2024, the presence of additional control measures that operate year-round and other changes in market conditions as a result of the rule lead to notable NOx reductions in the winter months.

[c] Applied risk estimate derived from April-September exposures to estimates of O_3 across the standard May-September warm season.

[d] Converted O_3 risk estimate metric from MDA1 to MDA8.

[e] Applied risk estimate derived from June-August exposures to estimates of O_3 across the standard May-September warm season.

[f] Applied risk estimate derived from full year exposures to estimates of O_3 across the standard May-September warm season.

[g] Converted O_3 risk estimate metric from DA24 to MDA8.

Table 5-3. Estimated Avoided $PM_{2.5}$ and Ozone-Related Mortality and Illnesses for the Final and More and Less Stringent Alternatives for 2024 (95% Confidence Interval) [a]

			Final	More Stringent Alternative	Less Stringent Alternative
Avoided premature mortality					
$PM_{2.5}$	Long-term exposure	Turner *et al*. (2016)[b]	4 (2 to 5)	4 (2 to 5)	--
		Di *et al*. (2017)	4 (3 to 4)	4 (3 to 4)	--
Ozone	Long-term exposure	Turner *et al*. (2016)	230 (160 to 300)	410 (280 to 530)	19 (13 to 25)
	Short-term exposure	Zanobetti *et al* (2008)[c] and Katsouyanni *et al* (2009)[b,d] pooled	10 (4 to 16)	18 (7 to 29)	1 (0 to 1)
		Katsouyanni *et al* (2009)[b,d]	10 (-6 to 26)	18 (-10 to 46)	1 (-0 to 2)
		Zanobetti *et al* (2008)[c]	10 (5 to 16)	18 (8 to 28)	1 (0 to 1)
$PM_{2.5}$- related non-fatal heart attacks among adults					
Short-term exposure		Peters et al. (2001)	4 (1 to 6)	4 (1 to 6)	--
		Pooled estimate	0 (0 to 1)	0 (0 to 1)	--
Morbidity effects					
Long-term exposure		Asthma onset[b,d] ($PM_{2.5}$ & O_3)	1,600 (1,400 to 1,800)	2,900 (2,500 to 3,300)	130 (110 to 150)
		Allergic rhinitis symptoms[e] ($PM_{2.5}$ & O_3)	9,200 (4,900 to 13,000)	17,000 (8,700 to 24,000)	770 (400 to 1,100)
		Stroke ($PM_{2.5}$)	0.2 (0 to 0.3)	0.2 (0 to 0.3)	--
		Lung cancer ($PM_{2.5}$)	0.4 (0.0 to 0.7)	0.4 (0.0 to 0.7)	--
		Hospital Admissions - Alzheimer's disease ($PM_{2.5}$)	2 (1 to 2)	2 (1 to 2)	--
		Hospital Admissions- Parkinson's disease ($PM_{2.5}$)	0.2 (0.1 to 0.3)	0.2 (0.1 to 0.3)	--
Short-term exposure		Hospital admissions- cardiovascular ($PM_{2.5}$)	0.5 (0.3 to 0.6)	0.5 (0.3 to 0.6)	--
		ED visits- cardiovascular ($PM_{2.5}$)	1 (-0 to 2)	1 (0 to 2)	--
		Hospital admissions—respiratory[h] ($PM_{2.5}$ & O_3)	27 (-7 to 60)	49 (-12 to 110)	2 (-1 to 5)
		ED visits —respiratory ($PM_{2.5}$ & O_3)	530 (150 to 1,100)	950 (260 to 2,000)	44 (12 to 92)
		Asthma symptoms[f] ($PM_{2.5}$ & O_3)	290,000 (-37,000 to 610,000)	530,000 (-66,000 to 1,100,000)	25,000 (-3,000 to 51,000)

	Minor restricted-activity days ($PM_{2.5}$ & O_3)	150,000 (60,000 to 230,000)	260,000 (110,000 to 410,000)	12,000 (4,800 to 19,000)
	Cardiac arrest ($PM_{2.5}$)	0.05 (-0.02 to 0.11)	0.05 (-0.02 to 0.11)	--
	Lost work days ($PM_{2.5}$)	380 (320 to 440)	380 (320 to 440)	--
	School absence days (O_3)	110,000 (-15,000 to 230,000)	200,000 (-28,000 to 410,000)	9,100 (-1,300 to 19,000)

[a] Values rounded to two significant figures.
[b] Applied risk estimate derived from April-September exposures to estimates of O_3 across the standard May-September warm season.
[c] Converted O_3 risk estimate metric from MDA1 to MDA8
[d] Applied risk estimate derived from June-August exposures to estimates of O_3 across the standard May-September warm season.
[e] Converted O_3 risk estimate metric from DA24 to MDA8
[f] Applied risk estimate derived from full year exposures to estimates of O_3 across the standard May-September warm season.

Table 5-4. Estimated Discounted Economic Value of Ozone-Attributable Premature Mortality and Illnesses for the Final Policy Scenarios in 2021 (95% Confidence Interval; millions of 2016$)[a,b]

	Final			More Stringent Alternative			Less Stringent Alternative		
3% Discount Rate	$230 ($58 to $480)[c]	*and*	$1,900 ($210 to $5,000)[d]	$230 ($58 to $480)[c]	*and*	$1,900 ($210 to $5,000)[d]	$22 ($6 to $47)[c]	*and*	$190 ($20 to $490)[d]
7% Discount Rate	$200 ($38 to $460)[c]	*and*	$1,700 ($170 to $4,500)[d]	$200 ($38 to $460)[c]	*and*	$1,700 ($170 to $4,500)[d]	$20 ($4 to $45)[c]	*and*	$170 ($17 to $440)[d]

[a] Values rounded to two significant figures. The two benefits estimates separated by the word "and" signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated changes in annual mean $PM_{2.5}$ and $PM_{2.5}$ -related benefits in 2024, but not 2021. As discussed in Chapter 4, in 2021, the only control measure expected to be adopted for compliance in the regulatory control alternatives analysis in this RIA is optimization of existing SCRs, and this measure will operate only during the ozone season. As discussed in Chapter 3, NOx reductions in the ozone season provide minimal $PM_{2.5}$ benefits since $PM_{2.5}$ nitrate concentrations, which result from conversion of NOx emissions to nitrate, are minimal during the warmer temperatures during the ozone season. Conversely, the conversion of nitrates to $PM_{2.5}$ is much greater in cooler (non-ozone season) months, and thus it becomes worthwhile to estimate $PM_{2.5}$ benefits from NOx reductions in those months. In 2024, the presence of additional control measures that operate year-round and other changes in market conditions as a result of the rule lead to notable NOx reductions in the winter months.
[c] Sum of ozone mortality estimated using the pooled Katsouyanni et al. (2009) and Zanobetti and Schwartz (2008) short-term risk estimate and the Di et al. (2017) long-term mortality risk estimate. As PM-related mortality quantified using risk estimates from the Di et al. (2017) and Turner et al. (2016) are within 5% of one another, in the interest of clarity and simplicity, we present the results estimated using the risk estimate from Di et al. (2017) alone.
[d] Sum of ozone mortality estimated using the long-term risk estimate and the Di et al. (2017) long-term mortality risk estimate. PM-related mortality quantified using risk estimates from the Di et al. (2017) and Turner et al. (2016) are within 5% of one another. In the interest of clarity and simplicity, we present the results estimated using the risk estimate from Di et al. (2017) alone.

Table 5-5. Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illnesses for the Final Policy Scenario in 2024 (95% Confidence Interval; millions of 2016$)[a]

	Final			More Stringent Alternative			Less Stringent Alternative[b]		
3% Discount Rate	$310 ($72 to $680)[c]	*and*	$2,400 ($250 to $6,200)[d]	$530 ($130 to $1,100)[c]	*and*	$4,200 ($450 to $11,000)[d]	$22 ($6 to $47)[c]	*and*	$190 ($20 to $490)[d]
7% Discount Rate	$280 ($48 to $640)[c]	*and*	$2,100 ($210 to $5,600)[d]	$470 ($84 to $1,100)[c]	*and*	$3,800 ($370 to $9,900)[d]	$20 ($4 to $45)[c]	*and*	$170 ($17 to $440)[d]

[a] Values rounded to two significant figures. The two benefits estimates separated by the word "and" signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] No PM-attributable benefits accrue for this scenario
[c] Sum of ozone mortality estimated using the pooled Katsouyanni et al. (2009) and Zanobetti and Schwartz (2008) short-term risk estimate and the Di et al. (2017) long-term mortality risk estimate. As PM-related mortality quantified using risk estimates from the Di et al. (2017) and Turner et al. (2016) are within 5% of one another, in the interest of clarity and simplicity, we present the results estimated using the risk estimate from Di et al. (2017). alone.
[d] Sum of ozone mortality estimated using the long-term risk estimate and the Di et al. (2017) long-term mortality risk estimate. PM-related mortality quantified using risk estimates from the Di et al. (2017) and Turner et al. (2016) are within 5% of one another. In the interest of clarity and simplicity, we present the results estimated using the risk estimate from Di et al. (2017) alone.

Table 5-6. Stream of Human Health Benefits from 2021 through 2040: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality and Long-Term $PM_{2.5}$ Mortality (Discounted at 3%; 95% Confidence Interval; millions of 2016$)

	Final	More Stringent Alternative	Less Stringent Alternative
2021*	$1,900	$1,900	$190
2022	$2,000	$2,000	$190
2023	$2,000	$2,000	$200
2024*	$2,400	$4,200	$190
2025	$2,400	$4,200	$200
2026	$2,500	$4,300	$200
2027	$2,400	$4,200	$190
2028	$2,500	$4,300	$200
2029	$2,500	$4,400	$210
2030	$2,600	$4,600	$210
2031	$2,600	$4,600	$210
2032	$2,700	$4,800	$220
2033	$2,600	$4,700	$220
2034	$2,700	$4,800	$220
2035	$2,800	$4,900	$230
2036	$2,800	$5,000	$230
2037	$2,900	$5,100	$230
2038	$2,800	$5,000	$230
2039	$2,800	$5,000	$230
2040	$2,900	$5,100	$240
Net Present Value	***$37,000***	***$61,000***	***$3,100***

*Year in which air quality was simulated. Ozone air quality was simulated in 2021 and 2024 while the formation of $PM_{2.5}$ was simulated only in 2024. Health benefits for all other years were linearly extrapolated or interpolated from model-simulated air quality in these years. This method assumes that ozone and $PM_{2.5}$ formation reaches a steady state beyond 2024. Benefits calculated as value of avoided: $PM_{2.5}$-attributable deaths (quantified using a concentration-response relationship from the Di et al. 2017 study); Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2017 study); and, $PM_{2.5}$ and ozone-related morbidity effects.

Table 5-7. Stream of Human Health Benefits from 2021 through 2040: Monetized Benefits Quantified as Sum of Short-Term Ozone Mortality and Long-Term $PM_{2.5}$ Mortality (Discounted at 7%; 95% Confidence Interval; millions of 2016$)

	Final	More Stringent Alternative	Less Stringent Alternative
2021*	$200	$200	$20
2022	$210	$210	$21
2023	$210	$210	$20
2024*	$280	$470	$21
2025	$290	$490	$21
2026	$290	$500	$22
2027	$300	$520	$22
2028	$310	$530	$23
2029	$320	$550	$24
2030	$330	$560	$25
2031	$340	$580	$25
2032	$350	$600	$26
2033	$360	$620	$27
2034	$370	$630	$28
2035	$380	$650	$28
2036	$390	$670	$29
2037	$400	$690	$30
2038	$410	$710	$31
2039	$430	$730	$32
2040	$440	$750	$33
Net Present Value	***$3,200***	***$5,100***	***$250***

*Year in which air quality was simulated. Ozone air quality was simulated in 2021 and 2024 while the formation of $PM_{2.5}$ was simulated only in 2024. Health benefits for all other years were linearly extrapolated or interpolated from model-simulated air quality in these years. This method assumes that ozone and $PM_{2.5}$ formation reaches a steady state beyond 2024. Benefits calculated as value of avoided: $PM_{2.5}$-attributable deaths (quantified using a concentration-response relationship from the Di et al. 2017 study); Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2017 study); and, $PM_{2.5}$ and ozone-related morbidity effects.

5.2 Estimated Climate Benefits from Reducing CO_2

We estimate the climate benefits for this final rulemaking using a measure of the social cost of carbon (SC-CO_2). The SC-CO_2 is the monetary value of the net harm to society associated with a marginal increase in CO_2 emissions in a given year, or the benefit of avoiding that increase. In principle, SC-CO_2 includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-CO_2, therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton. The SC-CO_2 is the theoretically appropriate values to use in conducting benefit-cost analyses of policies that affect CO_2 emissions.

We estimate the global social benefits of CO_2 emission reductions expected from this final rule using the SC-CO_2 estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* (IWG 2021). These SC-CO_2 estimates are interim values developed under Executive Order (E.O.) 13990 for use in benefit-cost analyses until an improved estimate of the impacts of climate change can be developed based on the best available science and economics. These SC-CO_2 estimates are the same as those used in the 2016 Final CSAPR Update RIA.

The SC-CO_2 estimates presented here were developed over many years, using transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in 2009, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices was established to ensure that agencies were using the best available science and to promote consistency in the SC-CO_2 values used across agencies. The IWG published SC-CO_2 estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate global climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs were run using a common set of input assumptions in each model for future population, economic, and CO_2 emissions growth, as well as equilibrium climate sensitivity (ECS) – a measure of the globally averaged temperature response to increased atmospheric CO_2 concentrations. These estimates were updated in 2013 based on new versions of each IAM.[11] In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC-CO_2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-CO_2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, *Valuing Climate Damages: Updating*

[11] Dynamic Integrated Climate and Economy (DICE) 2010 (Nordhaus 2010), Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8 (Anthoff and Tol 2013a, 2013b), and Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009 (Hope 2013).

Estimation of the Social Cost of Carbon Dioxide, and recommended specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies 2017). Shortly thereafter, in March 2017, President Trump issued Executive Order 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to ensure SC-CO_2 estimates used in regulatory analyses are consistent with the guidance contained in OMB's Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). Benefit-cost analyses following E.O. 13783, including the benefit-cost analysis in the proposal RIA,[12] used SC-CO_2 estimates that attempted to focus on the domestic impacts of climate change as estimated by the models to occur within U.S. borders and were calculated using two discount rates recommended by Circular A-4, 3 percent and 7 percent. All other methodological decisions and model versions used in SC- CO_2 calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

On January 20, 2021, President Biden issued Executive Order 13990, which re-established the IWG and directed it to ensure that the U.S. Government's estimates of the social cost of carbon, methane, and nitrous oxide (collectively referred to as SC-GHG) reflect the best available science and the recommendations of the National Academies (2017). The IWG was tasked with first reviewing the SC-GHG estimates currently used in Federal analyses and publishing interim estimates within 30 days of the E.O. that reflect the full impact of GHG emissions, including by taking global damages into account. The interim SC-CO_2 estimates published in February 2021 are used here to estimate the climate benefits for this final rulemaking. The E.O. instructs the IWG to undertake a fuller update of the SC-GHG estimates by January 2022 that takes into consideration the advice of the National Academies (2017) and other recent scientific literature.

The February 2021 TSD provides a complete discussion of the IWG's initial review conducted under E.O. 13990. In particular, the IWG found that the SC-GHG estimates used since E.O. 13783 fail to reflect the full impact of GHG emissions in multiple ways. First, the IWG

[12] The values used in the proposal RIA were interim values developed under E.O. 13783 for use in regulatory analyses. EPA followed E.O. 13783 by using SC-CO2 estimates reflecting impacts occurring within U.S. borders and 3% and 7% discount rates in our central analysis for the proposal RIA.

found that a global perspective is essential for SC-GHG estimates because climate impacts occurring outside U.S. borders can directly and indirectly affect the welfare of U.S. citizens and residents. Thus, U.S. interests are affected by the climate impacts that occur outside U.S. borders. Examples of affected interests include: direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration. In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. Therefore, in this final rule EPA centers attention on a global measure of SC-GHG. This approach is the same as that taken in EPA regulatory analyses over 2009 through 2016. As noted in the February 2021 TSD, the IWG will continue to review developments in the literature, including more robust methodologies for estimating SC-GHG values based on purely domestic damages, and explore ways to better inform the public of the full range of carbon impacts, both global and domestic. As a member of the IWG, EPA will likewise continue to follow developments in the literature pertaining to this issue.

Second, the IWG found that the use of the social rate of return on capital (7 percent under current OMB Circular A-4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC-GHG. Consistent with the findings of the National Academies (2017) and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context (IWG 2010, 2013, 2016a, 2016b), and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates. As a member of the IWG involved in the development of the February 2021 TSD, EPA agrees with this assessment, and will continue to follow developments in the literature pertaining to this issue.

While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC-GHG estimates, it set the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 TSD, the IWG has determined that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values for use in benefit-cost analyses: an average value resulting from the model runs for each of three discount rates (2.5%, 3%, and 5%), plus a fourth value, selected as the 95th percentile of estimates based on a 3 percent discount rate. The fourth value was included to provide information on potentially higher-than-expected economic impacts from climate change, conditional on the 3% estimate of the discount rate. As explained in the February 2021 TSD, this update reflects the immediate need to have an operational SC-GHG for use in regulatory benefit-cost analyses and other applications that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.

Table 5-8 summarizes the interim global SC-CO_2 estimates for the years 2015 to 2050. These estimates are reported in 2016 dollars but are otherwise identical to those presented in the IWG's 2016 TSD (IWG 2016a). For purposes of capturing uncertainty around the SC-CO_2 estimates in analyses, the IWG's February 2021 TSD emphasizes the importance of considering all four of the SC-CO_2 values. The SC-CO_2 increases over time within the models – i.e., the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2025 – because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

Table 5-8. Interim Global Social Cost of Carbon Values, 2020-2050 (2016$/Metric Tonne CO_2)

Emissions Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2020	$13	$47	$71	$140
2025	$15	$52	$77	$160
2030	$18	$57	$83	$170
2035	$20	$63	$90	$190
2040	$23	$67	$95	$210
2045	$26	$73	$100	$220
2050	$29	$78	$110	$240

Note: These SC-CO_2 values are identical to those reported in the 2016 TSD (IWG 2016a) adjusted for inflation to 2016 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) NIPA Table 1.1.9 (U.S. BEA 2021). The values are stated in $/metric tonne CO_2 (1 metric tonne equals 1.102 short tons) and vary depending on the year of CO_2 emissions. This table displays the values rounded to the nearest dollar; the annual unrounded values used in the calculations in this RIA are available on OMB's website: <https://www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/>.

Source: Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021)

There are a number of limitations and uncertainties associated with the SC-CO_2 estimates presented in Table 5-8. Some uncertainties are captured within the analysis, while other areas of uncertainty have not yet been quantified in a way that can be modeled. Figure 5-3 presents the quantified sources of uncertainty in the form of frequency distributions for the SC-CO_2 estimates for emissions in 2030. The distributions of SC-CO_2 estimates reflect uncertainty in key model parameters such as the equilibrium climate sensitivity, as well as uncertainty in other parameters set by the original model developers. To highlight the difference between the impact of the discount rate and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the SC-CO_2 estimates for each discount rate. As illustrated by the figure, the assumed discount rate plays a critical role in the ultimate estimate of the SC-CO_2. This is because CO_2 emissions today continue to impact society far out into the future, so with a higher discount rate, costs that accrue to future generations are weighted less, resulting in a lower estimate. As discussed in the February 2021 TSD, there are other sources of uncertainty that have not yet been quantified and are thus not reflected in these estimates.

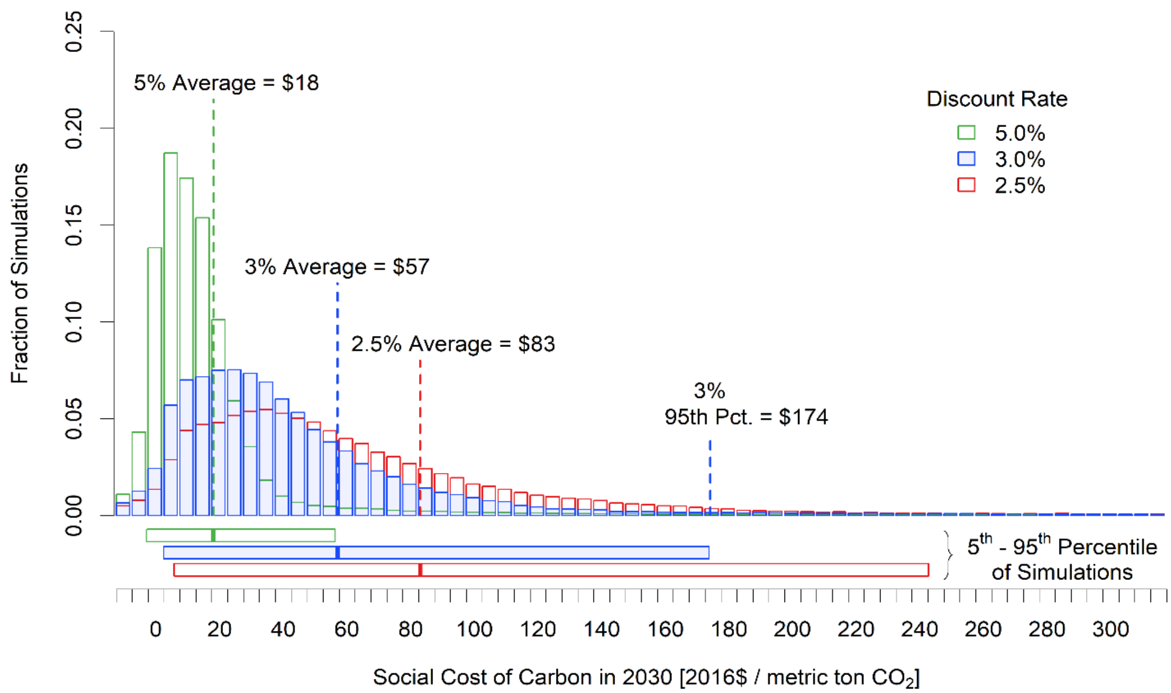

Figure 5-3. Frequency Distribution of SC-CO_2 Estimates for 2030[13]

The interim SC-CO_2 estimates presented in Table 5-8 have a number of limitations. First, the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower (IWG 2021). Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature and the science underlying their "damage functions" – i.e., the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages – lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. Likewise, the

[13] Although the distributions and numbers in Figure 5-3 are based on the full set of model results (150,000 estimates for each discount rate), for display purposes the horizontal axis is truncated with 0.78 percent of the estimates falling below the lowest bin displayed and 3.64 percent of the estimates falling above the highest bin displayed.

socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections.

The modeling limitations do not all work in the same direction in terms of their influence on the SC-CO_2 estimates. However, the IWG has recommended that, taken together, the limitations suggest that the interim SC-CO_2 estimates used in this final rule likely underestimate the damages from CO_2 emissions. In particular, the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (IPCC 2007), which was the most current IPCC assessment available at the time when the IWG decision over the ECS input was made, concluded that SC-CO_2 estimates "very likely…underestimate the damage costs" due to omitted impacts. Since then, the peer-reviewed literature has continued to support this conclusion, as noted in the IPCC's Fifth Assessment report (IPCC 2014) and other recent scientific assessments (e.g., IPCC 2018, 2019a, 2019b; U.S. Global Change Research Program (USGCRP) 2016, 2018; and National Academies 2016b, 2019). These assessments confirm and strengthen the science, updating projections of future climate change and documenting and attributing ongoing changes. For example, sea level rise projections from the IPCC's Fourth Assessment report ranged from 18 to 59 centimeters by the 2090s relative to 1980-1999, while excluding any dynamic changes in ice sheets due to the limited understanding of those processes at the time (IPCC 2007). A decade later, the Fourth National Climate Assessment projected a substantially larger sea level rise of 30 to 130 centimeters by the end of the century relative to 2000, while not ruling out even more extreme outcomes (USGCRP 2018). The February 2021 TSD briefly previews some of the recent advances in the scientific and economic literature that the IWG is actively following and that could provide guidance on, or methodologies for, addressing some of the limitations with the interim SC-CO_2 estimates. The IWG will be taking comment on how to incorporate the recommendations of the National Academies (2017) and other recent science including the advances discussed in the February 2021 TSD in the development of the fully updated SC-GHG estimates to be released by January of 2022 under E.O. 13990. To complement the IWG process, and as an active member of the IWG, the EPA will also be soliciting comment in forthcoming proposed rules that use the interim SC-CO_2 presented in this RIA.

Table 5-9 shows the estimated monetary value of the estimated changes in CO_2 emissions expected to occur over 2021-2040 for the Revised CSAPR Update, the more-stringent alternative, and the less-stringent alternative. EPA estimated the dollar value of the CO_2-related effects for each analysis year between 2021 and 2040 by applying the SC-CO_2 estimates, shown in Table 5-8, to the estimated changes in CO_2 emissions in the corresponding year under the regulatory options.[14] EPA then calculated the present value and annualized benefits from the perspective of 2020 by discounting each year-specific value to the year 2020 using the same discount rate used to calculate the SC-CO_2.[15]

Table 5-9. Estimated Global Climate Benefits from Changes in CO_2 Emissions 2021 - 2040 (Millions of 2016$)[a]

		Discount Rate and Statistic			
Regulatory Alternative	**Year**	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
Finalized Option	2021	0	1	1	2
	2022	46	143	206	434
	2023	94	290	417	882
	2024	102	311	444	946
	2025	109	331	473	1,011
	2030	128	373	525	1,146
	2035	98	273	380	838
	2040	127	340	467	1,043
More-Stringent Alternative	2021	1	2	3	7
	2022	76	237	341	720
	2023	156	480	689	1,460
	2024	204	623	892	1,898
	2025	254	771	1,100	2,350
	2030	323	939	1,322	2,885
	2035	316	878	1,222	2,698
	2040	383	1,025	1,410	3,146
	2021	0	1	1	3

[14] Under the baseline, CO_2 emissions are projected to rise through 2025 and then taper off through 2035 and rise during the rest of the period, reflecting increasing demand growth, changing generation mix patterns and the impact of retiring capacity. CO_2 emissions reductions as a result of the modeled policies follow a similar trend, which causes total climate benefit estimates to oscillate over time.

[15] According to OMB's Circular A-4 (2003), an "analysis should focus on benefits and costs that accrue to citizens and residents of the United States", and international effects should be reported separately. To correctly assess the total climate damages to U.S. citizens and residents, an analysis must account for impacts that occur within U.S. borders, climate impacts occurring outside U.S. borders that directly and indirectly affect the welfare of U.S. citizens and residents, and spillover effects from climate action elsewhere. The SC-CO_2 estimates used in regulatory analysis under revoked E.O. 13783, including in the RIA for the proposed rule, were an approximation of the climate damages occurring within U.S. borders only (e.g., $7/mt$CO_2$ (2016 dollars) and $9/mt$CO_2$ using a 3% discount rate for emissions occurring in 2021 and 2040, respectively). Applying the same estimate (based on a 3% discount rate) to the CO_2 emission reduction expected under the finalized option in this final rule would yield benefits from climate impacts within U.S borders of $0.1 million in 2021, increasing to $39.8 million in 2040. However, as discussed at length in the IWG's February 2021 TSD, estimates focusing on the climate impacts occurring solely within U.S. borders are an underestimate of the benefits of CO_2 mitigation accruing to U.S. citizens and residents, as well as being subject to a considerable degree of uncertainty due to the manner in which they are derived.

Less-Stringent Alternative	2022	39	122	176	371
	2023	80	248	356	754
	2024	81	248	355	755
	2025	82	248	353	755
	2030	93	271	381	831
	2035	73	203	282	623
	2040	91	242	333	743

[a] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

5.3 Total Benefits

Tables 5-10 through 5-12 present the total health and climate benefits for the final rule and the more and less stringent alternatives for 2021, 2025, and 2030. In each of these tables, for each discount rate and regulatory control alternative, multiple benefits estimates are presented reflecting alternative ozone and $PM_{2.5}$ mortality risk estimates.

Table 5-10. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2021 (millions of 2016$)[a]

SC-CO_2 Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only[b]
	3%	7%	
Final Rule			
5% (average)	$230 and $1,900	$200 and $1,700	$0
3% (average)	$230 and $1,900	$200 and $1,700	$1
2.5% (average)	$230 and $1,900	$200 and $1,700	$1
3% (95th percentile)	$230 and $1,900	$200 and $1,700	$2
More Stringent Alternative			
5% (average)	$260 and $1,900	$200 and $1,700	$1
3% (average)	$260 and $1,900	$200 and $1,700	$2
2.5% (average)	$260 and $1,900	$200 and $1,700	$3
3% (95th percentile)	$270 and $1,900	$210 and $1,700	$7
Less Stringent Alternative			
5% (average)	$20 and $190	$20 and $170	$0
3% (average)	$20 and $190	$20 and $170	$1
2.5% (average)	$20 and $190	$20 and $170	$1

3% (95th percentile)	$20 and $190	$20 and $170	$3

[a] The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates; the additional benefit estimates range from $0.24 million to $2.31 million in 2021 for the finalized option. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

Table 5-11. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2025 (millions of 2016$)[a]

SC-CO_2 Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only[b]
	3%	7%	
Final Rule			
5% (average)	$430 and $2,500	$400 and $2,300	$110
3% (average)	$650 and $2,700	$620 and $2,500	$330
2.5% (average)	$790 and $2,900	$760 and $2,700	$470
3% (95th percentile)	$1,300 and $3,400	$1,300 and $3,200	$1,000
More Stringent Alternative			
5% (average)	$790 and $4,500	$740 and $4,000	$250
3% (average)	$1,300 and $5,000	$1,300 and $4,600	$770
2.5% (average)	$1,600 and $5,300	$1,600 and $4,900	$1,100
3% (95th percentile)	$2,900 and $6,600	$2,900 and $6,200	$2,400
Less Stringent Alternative			
5% (average)	$100 and $280	$100 and $250	$80
3% (average)	$270 and $450	$270 and $420	$250
2.5% (average)	$370 and $550	$370 and $520	$350
3% (95th percentile)	$780 and $960	$780 and $930	$760

[a] The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates; the additional benefit estimates range from $109 million to $1,011 million in 2025 for the finalized option. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

Table 5-12. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2030 (millions of 2016$)[a]

$SC\text{-}CO_2$ Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only[b]
	3%	7%	
Final Rule			
5% (average)	$470 and $2,700	$460 and $2,600	$130
3% (average)	$710 and $3,000	$700 and $2,900	$370
2.5% (average)	$870 and $3,100	$860 and $3,000	$530
3% (95th percentile)	$1,400 and $3,700	$1430 and $3,600	$1,100
More Stringent Alternative			
5% (average)	$910 and $4,900	$880 and $4,200	$320
3% (average)	$1,500 and $5,500	$1,500 and $4,800	$940
2.5% (average)	$1,900 and $5,900	$1,900 and $5,200	$1,300
3% (95th percentile)	$3,500 and $7,500	$3,500 and $6,800	$2,900
Less Stringent Alternative			
5% (average)	$120 and $300	$110 and $270	$90
3% (average)	$300 and $480	$290 and $450	$270
2.5% (average)	$410 and $590	$400 and $560	$380
3% (95th percentile)	$860 and $1,040	$850 and $1,010	$830

[a] The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon ($SC\text{-}CO_2$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four $SC\text{-}CO_2$ estimates; the additional benefit estimates range from $128 million to $1,146 million in 2030 for the finalized option. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

5.4 Unquantified Benefits

In the presence of sunlight, NO_X and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions generally reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local levels of VOCs as discussed in Chapter 3. The final rule would also reduce emissions of NO_X throughout the year. Because NO_X is also a precursor to formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would thus reduce the incidence of $PM_{2.5}$-

attributable health effects.[16] Reducing emissions of NO_X would also reduce ambient exposure to NO_2 and its associated health effects.

Data, time, and resource limitations prevented EPA from quantifying the estimated impacts or monetizing estimated benefits associated with exposure to NO_2 (independent of the role NO_2 plays as precursors to $PM_{2.5}$), as well as ecosystem effects, and visibility impairment due to the absence of air quality modeling data for these pollutants in this analysis. Lack of quantification does not imply that there are no additional benefits associated with reductions in exposures to ozone, $PM_{2.5}$, or NO_2. In this section, we provide a qualitative description of these benefits, which are listed in Table 5-13.

Table 5-13. Unquantified Health and Welfare Benefits Categories

Category	Effect	Effect Quantified	Effect Monetized	More Information
Improved Human Health				
Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions	—	—	NO_2 ISA[2]
	Chronic lung disease hospital admissions	—	—	NO_2 ISA[2]
	Respiratory emergency department visits	—	—	NO_2 ISA[2]
	Asthma exacerbation	—	—	NO_2 ISA[2]
	Acute respiratory symptoms	—	—	NO_2 ISA[2]
	Premature mortality	—	—	NO_2 ISA[2,3,4]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO_2 ISA[3,4]
Improved Environment				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[2]
	Visibility in residential areas	—	—	PM ISA[2]
Reduced effects on materials	Household soiling	—	—	PM ISA[2,3]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[3]
Reduced effects from PM deposition (metals and organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[3]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[2]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[2]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[2]
	Damage to urban ornamental plants	—	—	Ozone ISA[3]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[2]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[3]
	Other non-use effects			Ozone ISA[3]

[16] This RIA does not quantify $PM_{2.5}$-related benefits associated with direct $PM_{2.5}$ and SO_2 emission reductions. As discussed in Chapter 4, EPA does not estimate significant direct $PM_{2.5}$ and SO_2 emission reductions as a result of this rule.

	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[3]
Reduced effects from acid deposition	Recreational fishing	—	—	NO_x SO_x ISA[2]
	Tree mortality and decline	—	—	NO_x SO_x ISA[3]
	Commercial fishing and forestry effects	—	—	NO_x SO_x ISA[3]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO_x SO_x ISA[3]
	Other non-use effects			NO_x SO_x ISA[3]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO_x SO_x ISA[3]
Reduced effects from nutrient enrichment	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[3]
	Coastal eutrophication	—	—	NO_x SO_x ISA[3]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[3]
	Other non-use effects			NO_x SO_x ISA[3]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NO_x SO_x ISA[3]
Reduced vegetation effects from ambient exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NO_x SO_x ISA[3]
	Injury to vegetation from NO_x exposure	—	—	NO_x SO_x ISA[3]

[1] These endpoints are generally quantified and monetized when EPA quantitatively characterizes the benefits of changes in $PM_{2.5}$ and Ozone.

[2] We assess these benefits qualitatively due to data and resource limitations for this RIA.

[3] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.

[4] We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

5.4.1 NO_2 Health Benefits

In addition to being a precursor to $PM_{2.5}$ and ozone, NOx emissions are also linked to a variety of adverse health effects associated with direct exposure. We were unable to estimate the health benefits associated with reduced NO_2 exposure in this analysis. Following a comprehensive review of health evidence from epidemiologic and laboratory studies, the Integrated Science Assessment for Oxides of Nitrogen —Health Criteria (NOx ISA) (U.S. EPA, 2016c) concluded that there is a likely causal relationship between respiratory health effects and short-term exposure to NO_2. These epidemiologic and experimental studies encompass a number of endpoints including emergency department visits and hospitalizations, respiratory symptoms, airway hyperresponsiveness, airway inflammation, and lung function. The NOx ISA also concluded that the relationship between short-term NO_2 exposure and premature mortality was "suggestive but not sufficient to infer a causal relationship," because it is difficult to attribute the mortality risk effects to NO_2 alone. Although the NOx ISA stated that studies consistently reported a relationship between NO_2 exposure and mortality, the effect was generally smaller than that for other pollutants such as PM.

5.4.2 Ozone Welfare Benefits

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2020b). Sensitivity to ozone is highly variable across species, with over 65 plant species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced yield and quality of crops, visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services.

5.4.3 NO_2 Welfare Benefits

As described in the Integrated Science Assessment for Oxides of Nitrogen and Sulfur — Ecological Criteria (NOx/SOx ISA) (U.S. EPA, 2008b), NOx emissions also contribute to a variety of adverse welfare effects, including those associated with acidic deposition, visibility impairment, and nutrient enrichment. Deposition of nitrogen causes acidification, which can cause a loss of biodiversity of fishes, zooplankton, and macro invertebrates in aquatic ecosystems, as well as a decline in sensitive tree species, such as red spruce (*Picea rubens*) and sugar maple (*Acer saccharum*) in terrestrial ecosystems. In the northeastern U.S., the surface waters affected by acidification are a source of food for some recreational and subsistence fishermen and for other consumers and support several cultural services, including aesthetic and educational services and recreational fishing. Biological effects of acidification in terrestrial ecosystems are generally linked to aluminum toxicity, which can cause reduced root growth, restricting the ability of the plant to take up water and nutrients. These direct effects can, in turn, increase the sensitivity of these plants to stresses, such as droughts, cold temperatures, insect pests, and disease leading to increased mortality of canopy trees. Terrestrial acidification affects several important ecological services, including declines in habitat for threatened and endangered species (cultural), declines in forest aesthetics (cultural), declines in forest productivity (provisioning), and increases in forest soil erosion and reductions in water retention (cultural and regulating). (U.S. EPA, 2008b)

Deposition of nitrogen is also associated with aquatic and terrestrial nutrient enrichment. In estuarine waters, excess nutrient enrichment can lead to eutrophication. Eutrophication of estuaries can disrupt an important source of food production, particularly fish and shellfish production, and a variety of cultural ecosystem services, including water-based recreational and aesthetic services. Terrestrial nutrient enrichment is associated with changes in the types and number of species and biodiversity in terrestrial systems. Excessive nitrogen deposition upsets the balance between native and nonnative plants, changing the ability of an area to support biodiversity. When the composition of species changes, then fire frequency and intensity can also change, as nonnative grasses fuel more frequent and more intense wildfires. (U.S. EPA, 2008b)

5.4.4 Visibility Impairment Benefits

Reducing secondary formation of $PM_{2.5}$ would improve levels of visibility in the U.S. because suspended particles and gases degrade visibility by scattering and absorbing light (U.S. EPA, 2009). Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Particulate sulfate is the dominant source of regional haze in the eastern U.S. and particulate nitrate is an important contributor to light extinction in California and the upper Midwestern U.S., particularly during winter (U.S. EPA, 2009). Previous analyses (U.S. EPA, 2011a) show that visibility benefits can be a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility-related benefits, and we are also unable to determine whether the emission reductions associated with the final emission guidelines would be likely to have a significant impact on visibility in urban areas or Class I areas.

Reductions in emissions of NO_2 will improve the level of visibility throughout the United States because these gases (and the particles of nitrate and sulfate formed from these gases) impair visibility by scattering and absorbing light (U.S. EPA, 2009). Visibility is also referred to as visual air quality (VAQ), and it directly affects people's enjoyment of a variety of daily activities (U.S. EPA, 2009). Good visibility increases quality of life where individuals live and work, and where they travel for recreational activities, including sites of unique public value, such as the Great Smoky Mountains National Park (U. S. EPA, 2009).

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CHAPTER 6: STATUTORY AND EXECUTIVE ORDER REVIEWS

Overview

This chapter presents the statutory and executive orders applicable to EPA rules, and discusses EPA's actions taken pursuant to these orders.

6.1 Executive Order 12866: Regulatory Planning and Review

This action is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. EPA prepared an analysis of the potential costs and benefits associated with this final action.

6.2 Paperwork Reduction Act

This final action will not impose any new information collection burden under the PRA. This final action relocates certain existing information collection requirements for certain sources from subpart EEEEE of 40 CFR part 97 to a new subpart GGGGG of 40 CFR part 97, but neither changes the inventory of sources subject to information collection requirements nor changes any existing information collection requirements for any source. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060-0667.

6.3 Regulatory Flexibility Act

EPA certifies that this action will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (RFA). The small entities subject to the requirements of this action are small businesses, small organizations, and small governmental jurisdictions. EPA has determined that no small entities potentially affected by the rule will have compliance costs greater than 1 percent of annual revenues in 2021. Details of this analysis are presented below.

The Regulatory Flexibility Act (5 U.S.C. 601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104-121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed 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.

EPA conducted regulatory flexibility analysis at the ultimate (i.e., highest) level of ownership, evaluating parent entities with the largest share of ownership in at least one potentially-affected EGU included in EPA's base case using the IPM v.6, used in this RIA.[1] This analysis draws on the "parsed" unit-level estimates using IPM results for 2021, as well as ownership, employment, and financial information for the potentially affected small entities drawn from other resources described in more detail below. This analysis is focused on estimating impacts in 2021 because implementation of the illustrative EGU controls occurs in the 2021 ozone season.

EPA identified the size of ultimate parent entities by using the Small Business Administration (SBA) size standard guidelines.[2] The criteria for size determination vary by the organization/operation category of the ultimate parent entity, as follows:

- Privately-owned (non-government) entities (see Table 6-1)
    - Privately-owned entities include investor-owned utilities, non-utility entities, and entities with a primary business other than electric power generation.
    - For entities with electric power generation as a primary business, small entities are those with less than the threshold number of employees specified by SBA for each of the relevant North American Industry Classification System (NAICS) sectors (NAICS 2211).

[1] Detailed documentation for IPM v.6 is available at: http://www.epa.gov/airmarkets/powersectormodeling.html.
[2] U.S. Small Business Administration (SBA). 2019. Small Business Size Standards, effective as of August 19, 2019 and available at the following link: https://www.sba.gov/sites/default/files/2019-08/SBA%20Table%20of%20Size%20Standards_Effective%20Aug%2019%2C%202019.pdf.

    - For entities with a primary business other than electric power generation, the relevant size criteria are based on revenue, assets, or number of employees by NAICS sector.[3]
- Publicly-owned entities
    - Publicly-owned entities include federal, state, municipal, and other political subdivision entities.
    - The federal and state governments are considered to be large. Municipalities and other political units with populations fewer than 50,000 ae considered to be small.
- Rural Electric Cooperatives
    - Small entities are those with fewer than the threshold level of employees or revenue specified by SBA for each of the relevant NAICS sectors.

6.3.1 Identification of Small Entities

In this analysis, EPA considered EGUs that meet the following five criteria: 1) EGU is represented in NEEDS v6; 2) EGU is fossil fuel-fired; 3) EGU is located in a state covered by this rule; 4) EGU is neither a cogeneration unit nor solid waste incineration unit; and 5) EGU capacity is 25 MW or larger. EPA next refined this list of EGUs, narrowing it to those that exhibit at least one of the following changes, in comparison to the baseline.

- Summer fuel use (BTUs) changes by +/- 1 percent or more
- Summer generation (GWh) changes by +/- 1 percent or more
- NOx summer emissions (tons) changes by +/- 1 percent or more

Based on these criteria, EPA identified a total of 97 potentially affected EGUs warranting examination in this RFA analysis. Next, we determined power plant ownership information, including the name of associated owning entities, ownership shares, and each entity's type of ownership. We primarily used data from Ventyx, supplemented by limited research using

[3] Certain affected EGUs are owned by ultimate parent entities whose primary business is not electric power generation.

publicly available data.[4] Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types.[5] 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, EPA used both the D&B Hoover's online database and the Ventyx database to identify the ultimate owners of power plant owners identified in the Ventyx database. This was necessary, as many majority owners of power plants (listed in Ventyx) are themselves owned by other ultimate parent entities (listed in D&B Hoover's).[6] In these cases, the ultimate parent entity was identified via D&B Hoover's, whether domestically or internationally owned.

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

[4] The Ventyx Energy Velocity Suite database consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: www.ventyx.com.
[5] Throughout this analysis, EPA refers to the owner with the largest ownership share as the "majority owner" even when the ownership share is less than 51 percent.
[6] 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/products/marketing-sales/dnb-hoovers.html.

below which an entity is considered small. SBA guidelines list all industries, along with their associated NAICS code 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 6-1. 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 EPA's IPM base case.

Table 6-1. SBA Size Standards by NAICS Code

NAICS Codes	NAICS U.S. Industry Title	Size Standards (millions of dollars)	Size Standards (number of employees)
221111	Hydroelectric Power Generation		500
221112	Fossil Fuel Electric Power Generation		750
221113	Nuclear Electric Power Generation		750
221114	Solar Electric Power Generation		250
221115	Wind Electric Power Generation		250
221116	Geothermal Electric Power Generation		250
221117	Biomass Electric Power Generation		250
221118	Other Electric Power Generation		250
221121	Electric Bulk Power Transmission and Control		500
221122	Electric Power Distribution		1000
221210	Natural Gas Distribution		1000
221310	Water Supply and Irrigation Systems	$30	
221320	Sewage Treatment Facilities	$22	
221330	Steam and Air-Conditioning Supply	$16	

Note: Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective August 19, 2019. Available at the following link: https://www.sba.gov/document/support--table-size-standards).
Source: SBA, 2019

EPA compared the relevant entity size criterion for each ultimate parent entity to the SBA size standard noted in Table 6-1. 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**: EPA used the D&B Hoover's database as the primary source for information on ultimate parent entity employee numbers, revenue, and assets.[7] In parallel, EPA also considered estimated revenues from affected EGUs based on analysis of parsed-file estimates for the rule. 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.

[7] Estimates of sales were used in lieu of revenue estimates when revenue data was unavailable.

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

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. In total EPA identified 89 potentially affected EGUs, owned by 15 entities. Of these, EPA identified 7 potentially affected EGUs owned by 2 small entities[8] included in EPA's Base Case.

6.3.2 Overview of Analysis and Results

This section presents the methodology and results for estimating the impact of the Revised CSAPR Update on small entities in 2021 based on the following endpoints:

- annual economic impacts of the Revised CSAPR Update on small entities, and
- ratio of small entity impacts to revenues from electricity generation.

6.3.2.1 Methodology for Estimating Impacts of the Revised CSAPR Update on Small Entities

An entity can comply with the Revised CSAPR Update through some combination of the following: optimizing existing SCRs, turning on idled SCR controls, optimizing existing SNCR controls, using allocated allowances, purchasing allowances, or reducing emissions through a reduction in generation. Additionally, units with more allowances than needed can sell these allowances in the market. The chosen compliance strategy will be primarily a function of the unit's marginal control costs and its position relative to the marginal control costs of other units.

To attempt to account for each potential control strategy, EPA estimates compliance costs as follows:

$$C_{Compliance} = \Delta\ C_{Operating+Retrofit} + \Delta\ C_{Fuel} + \Delta\ C_{Allowances} + \Delta\ C_{Transaction} + \Delta\ R$$

[8] Both of these small entities are in NAICS 221118, which is defined as establishments primarily engaged in operating electric power generation facilities (except hydroelectric, fossil fuel, nuclear, solar, wind, geothermal, biomass). These facilities convert other forms of energy, such as tidal power, into electric energy.

where C represents a component of cost as labeled, and Δ R represents the value of foregone electricity generation, calculated as the difference in revenues between the base case and the Revised CSAPR Update in 2021.

Realistically, compliance choices and market conditions can combine such that an entity may actually experience a savings in any of the individual components of cost. Under the Revised CSAPR Update, some units will forgo some level of electricity generation (and thus revenues) to comply and this impact will be lessened on these entities by the projected increase in electricity prices under the Revised CSAPR Update. On the other hand, those increasing generation levels will see an increase in electricity revenues and as a result, lower net compliance costs. If entities are able to increase revenue more than an increase in fuel cost and other operating costs, ultimately, they will have negative net compliance costs (or savings). Overall, small entities are not projected to install relatively costly emissions control retrofits but may choose to do so in some instances. Because this analysis evaluates the total costs along each of the compliance strategies laid out above for each entity, it inevitably captures savings or gains such as those described. As a result, what we describe as cost is really more of a measure of the net economic impact of the rule on small entities.

For this analysis, EPA used IPM-parsed output to estimate costs based on the parameters above, at the unit level. These impacts were then summed for each small entity, adjusting for ownership share. Net impact estimates were based on the following: operating and retrofit costs, sale or purchase of allowances, and the change in fuel costs or electricity generation revenues under the Revised CSAPR Update relative to the base case. These individual components of compliance cost were estimated as follows:

(1) **Operating and retrofit costs:** Using engineering analytics, EPA identified which compliance option was selected by each EGU in 2021 (i.e., SCR optimization or turning on existing SCR controls) and applied the appropriate cost to this choice. EPA assumes that state of the art combustion controls may be installed in 2022 and are not part of the controls available in 2021. As part of the illustrative emission budgets modeled for this rule, SNCR optimization was included from 2022 forward.

(2) **Sale or purchase of allowances:** To estimate the value of allowances holdings, allocated allowances were subtracted from projected emissions, and the difference was then multiplied by $1,600 (2016$) per ton, which is the marginal cost of NO_X reductions used to set the modeled budgets in the Revised CSAPR Update. While this is a reasonable approximation, it is possible that the actual allowance price could be lower. Units were assumed to purchase or sell allowances to exactly cover their projected emissions under the Revised CSAPR Update.

(3) **Fuel costs:** The change in fuel expenditures under the Revised CSAPR Update was estimated by taking the difference in projected fuel expenditures between the IPM estimates for the Revised CSAPR Update and the base case.

(4) **Value of electricity generated:** To estimate the value of electricity generated, the projected level of electricity generation is multiplied by the regional-adjusted retail electricity price ($/MWh) estimate, for all entities except those categorized as private in Ventyx. For private entities, EPA used the wholesale electricity price instead of the retail electricity price because most of the private entities are independent power producers (IPP). IPPs sell their electricity to wholesale purchasers and do not own transmission facilities. Thus, their revenue was estimated with wholesale electricity prices.

(5) **Administrative costs:** Because most affected units are already monitored as a result of other regulatory requirements, EPA considered the primary administrative cost to be transaction costs related to purchasing or selling allowances. EPA assumed that transaction costs were equal to 1.5 percent of the total absolute value of the difference between a unit's allocation and projected NO_X emissions. This assumption is based on market research by ICF.

6.3.2.2 Results

The potential impacts of the Revised CSAPR Update on small entities are summarized in Table 6-2. All costs are presented in 2016$. EPA estimated the annual net compliance cost to small entities to be approximately $0.04 million in 2021.

Table 6-2. Projected Impact of the Revised CSAPR Update on Small Entities in 2021

EGU Ownership Type	Number of Potentially Affected Entities	Total Net Compliance Cost ($2016 millions)	Number of Small Entities with Compliance Costs >1% of Generation Revenues	Number of Small Entities with Compliance Costs >3% of Generation Revenues
Cooperative	1	0.04	0	0
Private	1	0.00	0	0
Total	2	0.04	0	0

Source: IPM analysis

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. Although this metric is commonly used in EPA impact analyses, it makes the most sense when as a general matter an analysis is looking at small businesses that operate in competitive environments.[9] However, small businesses in the electric power industry often operate in a price-regulated environment where they are able to recover expenses through rate increases. Given this, EPA considers the 1 percent measure in this case a crude measure of the price increases these small entities will be asking of rate commissions or making at publicly owned companies. Of the 2 small entities considered in this analysis, neither is projected to experience compliance costs greater than 1 percent of generation revenues in 2021. EPA has concluded that there is no significant economic impact on a substantial number of small entities (no SISNOSE) for this rule.

The separate components of annual costs to small entities under the Revised CSAPR Update are summarized in Table 6-3. The most significant components of incremental cost to the cooperative category under the Revised CSAPR Update are due to higher operating costs (reflecting the cost of controls). Among the private category, however, reduced generation is the key driver. Total impacts to the private category are well below $10,000.

[9] U.S. EPA. EPA's Action Development Process. Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as Amended by the Small Business Regulatory Enforcement Fairness Act. September 2006. Available at https://www.epa.gov/sites/production/files/2015-06/documents/guidance-regflexact.pdf.

Table 6-3. Incremental Annual Costs under the Revised CSAPR Update Summarized by Ownership Group and Cost Category in 2021 (2016$ millions)

EGU Ownership Type	Operating Cost	Net Purchase of Allowances	Fuel Cost	Lost Electricity Revenue	Administrative Cost
Cooperative	0.06	0.00	-0.02	0.00	0.00
Private	0.00	0.00	0.00	0.00	0.00

Source: IPM analysis

6.3.3 Summary of Small Entity Impacts

EPA examined the potential economic impacts to small entities associated with this rule based on assumptions of how the affected states will implement control measures to meet their emissions. To summarize, of the 2 small entities potentially affected, none are projected to experience compliance costs in excess of 1 percent of revenues in 2021, based on assumptions of how the affected states implement control measures to meet their emissions budgets as set forth in this rule.

EPA has lessened the impacts for small entities by excluding all units smaller than 25 MW. This exclusion, in addition to the exemptions for cogeneration units and solid waste incineration units, eliminates the burden of higher costs for a substantial number of small entities located in the 12 states for which EPA is promulgating FIPs.

6.4 Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Public Law 104-4) (UMRA) establishes requirements for federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that includes any Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year. A Federal mandate is defined under section 421(6) of the UMRA, 2 U.S.C. 658(6), to be either a Federal intergovernmental mandate or a Federal private sector mandate, as defined by the UMRA. A Federal intergovernmental mandate, in turn, is defined to include a regulation that would impose an enforceable duty upon State, Local, or Tribal governments, UMRA section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is a condition of Federal assistance, UMRA section 421(5)(A)(i)(I). A Federal private sector mandate includes a regulation that would impose an enforceable duty upon the private sector, with certain exceptions, UMRA section 421(7)(A), 2 U.S.C. 658(7)(A).

This final action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and will not significantly or uniquely affect small governments. Note that EPA expects the final rule to potentially have an impact on only one category of government-owned entities (municipality-owned entities). This analysis does not examine potential indirect economic impacts associated with the final rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on government entities.

6.5 Executive Order 13132: Federalism

This final action does not have federalism implications. As finalized, this final action will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

6.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law.

This final action implements EGU NO_X ozone season emission reductions in 12 eastern states (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia.). However, at this time, none of the existing or planned EGUs affected by this rule are owned by tribes or located in Indian country. This action may have tribal implications if a new affected EGU is built in Indian country. Additionally, tribes have a vested interest in how this rule affects air quality.

In developing the CSAPR, which was promulgated on July 6, 2011, to address interstate transport of ozone pollution under the 1997 ozone NAAQS, EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing that regulation to allow for meaningful and timely tribal input into its development. A summary of that consultation is provided at 76 FR 48346.

In that rulemaking, EPA received comments from several tribal commenters regarding the availability of the CSAPR allowance allocations to new units in Indian country. EPA responded to these comments by instituting Indian country new unit set-asides in the final CSAPR. In order to protect tribal sovereignty, these set-asides are managed and distributed by the federal government regardless of whether the CSAPR in the adjoining or surrounding state is implemented through a FIP or SIP. While there are no existing affected EGUs in Indian country covered by this action, the Indian country set-asides will ensure that any future new units built in Indian country will be able to obtain the necessary allowances. This rule maintains the Indian country new unit set-aside and adjusts the amounts of allowances in each set-aside according to the same methodology of the CSAPR and the CSAPR Update.

EPA consulted with tribal officials early in the process of developing this rule in accordance with the EPA Policy on Consultation and Coordination with Indian Tribes (May 2011). Before proposing this rule, EPA informed tribes of the rule's development on a National Tribal Air Association (NTAA) monthly air policy conference call that took place on June 25, 2020. In a separate NTAA call on October 20, 2020, EPA gave an overview of the proposed rule. In order to permit tribes to have meaningful and timely input into the development of the final rule, EPA offered consultation to tribal leaders. On October 30, 2020, EPA sent out letters via electronic mail to all 574 federally recognized tribes informing them of this action, offering consultation and requesting comment on this rulemaking. Courtesy copies of the letters were also sent via email to tribal air staff and tribal environmental professionals. EPA also sent courtesy copies to EPA's Regional Tribal Air Coordinators for notification to their tribes. To further provide tribes with the resources that they might require to engage in effective consultation, EPA also held an informational webinar on the rule on November 9, 2020. EPA did not receive any requests for consultation on this rule.

6.7 Executive Order 13045: Protection of Children from Environmental Health & Safety Risks

EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2-202 of the Executive Order. This action is not subject to Executive Order 13045 because it implements a previously promulgated health-based federal standard. This action's health and risk assessments are contained in Chapter 5 of the accompanying RIA. EPA believes that the ozone reductions, $PM_{2.5}$ reductions, and CO_2 reductions from this final rule will further improve children's health.

6.8 Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. EPA has prepared a Statement of Energy Effects for the regulatory control alternative as follows. The Agency estimates a much less than 1 percent change in retail electricity prices on average across the contiguous U.S. in 2021, and a much less than 1 percent reduction in coal-fired electricity generation in 2021 as a result of this rule. EPA projects that utility power sector delivered natural gas prices will change by less than 1 percent in 2021. For more information on the estimated energy effects, please see Chapter 4 of this RIA.

6.9 National Technology Transfer and Advancement Act

The rulemaking does not involve technical standards.

6.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Because of the need to meet the court-ordered signature deadline on this action, EPA did not have sufficient time to undertake a definitive assessment of the impacts of this final rule on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). EPA does not have information at this time that would suggest that this rule has the potential to result in disproportionately high and adverse human health or environmental impacts on vulnerable populations or overburdened communities; however, EPA is also not currently in a position to make a determination to this effect. For a longer discussion of a framework for assessing potential EJ concerns for future rulemakings, please see Section X.J. of the final rule preamble.

Ozone pollution from power plants has both local and regional components: part of the pollution in a given location—even in locations near emission sources—is due to emissions from nearby sources and part is due to emissions that are transported in the atmosphere over large distances and mix with emissions from other sources. Undertaken to implement CAA section 110(a)(2)(D), this action addresses that “significant” portion of contribution from upwind states to a nonattainment or maintenance receptor. As a result, the rule will reduce exposures to ozone in areas that are struggling to attain or maintain the 2008 ozone NAAQS. By addressing maintenance receptors, this rule reduces the likelihood that areas close to the level of the standard will exceed the current health-based standards in the future. The rule will result in incidental reductions in ozone in other areas, as well as reducing emissions of PM and other pollutants from EGUs that have both localized and distant impacts.

At the same time, this action alone cannot fully resolve any disproportionate impacts of ozone levels in downwind areas. Rather, it eliminates upwind state “significant contribution,” thus ameliorating those conditions and improving downwind air quality. While this rule is expected to reduce interstate ozone transport and thus to yield overall health and environmental benefits, further analysis would be required to assess potential environmental justice concerns – including, for example, whether the downwind air quality benefits are equitably distributed.[10]

It is important to note that nothing in this final rule allows sources to violate their title V permit or any other federal, state, or local emissions or air quality requirements. Moreover, CAA section 110(a)(2)(D) addresses transport of criteria pollutants between states and is only one of many provisions of the CAA that provide EPA, states, and local governments with authorities to reduce exposure to ozone in communities. These legal authorities work together to reduce

[10] A potential environmental justice concern is “the actual or potential lack of fair treatment or meaningful involvement of minority populations, low-income populations, tribes, and indigenous peoples in the development, implementation and enforcement of environmental laws, regulations and policies” EPA, Guidance on Considering Environmental Justice During the Development of Regulatory Actions (May 2015).

exposure to these pollutants in communities, including for minority, low-income, and tribal populations, and provide substantial health benefits to both the general public and sensitive sub-populations.

EPA informed tribal communities of its development of this rule on a National Tribal Air Association – EPA air policy conference call on June 25, 2020. EPA also held two informational webinars for tribes and environmental justice communities on November 9, 2020 and November 10, 2020, respectively, where EPA presented an overview of the rule and provided tribes and communities with resources that they might require to engage in the public comment process.

CHAPTER 7: COMPARISON OF BENEFITS AND COSTS

Overview

EPA performed an analysis to estimate the costs and benefits of compliance with the Revised CSAPR Update and more and less stringent alternatives. EPA is promulgating electric generating unit (EGU) oxides of nitrogen (NO_X) ozone season emissions budgets for 12 states.[1] This action finds that for these states, their projected 2021 ozone season NOx emissions significantly contribute to downwind states' nonattainment and/or maintenance problems for the 2008 ozone national ambient air quality standards (NAAQS). For these 12 states, EPA amends their federal implementation plans (FIPs) to revise the existing Cross-State Air Pollution Rule (CSAPR) NOx Ozone Season Group 2 emissions budgets for EGUs and implement the revised budgets beginning in the 2021 ozone season (May 1, 2021 - September 30, 2021) via a new CSAPR NOx Ozone Season Group 3 Trading Program.

The Revised CSAPR Update state budgets reflect the optimization of existing selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR) controls and installation of state-of-the-art NO_X combustion controls, at an estimated representative cost of $1,800 per ton (2016$). For the RIA, in order to implement the OMB Circular A-4 requirement for fulfilling Executive Order (E.O.) 12866 to assess one less stringent and one more stringent alternative to the rule, EPA is also analyzing EGU NO_X ozone season emissions budgets reflecting NO_X reduction strategies that are widely available at a uniform cost of $9,600 per ton (2016$) and strategies that are widely available at a uniform cost of $500 per ton (2016$). These alternatives are used to illustrate the monetized cost and benefit impacts of varying program stringency. They are designed to show the effects of more stringent and less stringent NOx reduction requirements in a regulatory structure that is otherwise the same as the final NOx emissions budgets. We show the results for 2021 to reflect the year in which implementation of this rule begins, for 2025 to reflect full implementation of the rule, and 2030 to show the continued costs and benefits of the rule. This RIA evaluates how the EGUs covered by the rule are expected to reduce their emissions in response to the requirements and flexibilities provided by the remedy implemented

[1] The 12 states are Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia.

by the Revised CSAPR Update and the benefits, costs and impacts of their expected compliance behavior. This chapter summarizes these results.

7.1 Results

The rule and regulatory control alternatives' compliance costs are estimated using the IPM model and an evaluation of control technologies evaluated outside of IPM. As shown in Chapter 4, the estimated annual compliance costs to implement the rule, as described in this document, are approximately $5 million in 2021 and $2 million in 2025 (2016$). As described in Section 4.5, this RIA uses compliance costs as a proxy for social costs. As shown in Chapter 5, the estimated monetized health benefits from implementation of the rule are approximately $230 and $1,900 million in 2021 (2016$, based on a real discount rate of 3 percent). For 2025, the estimated monetized health benefits from implementation of the rule are approximately $320 and $2,400 million (2016$, based on a real discount rate of 3 percent). The two estimates of the benefits and net-benefits for each discount rate reflect alternative ozone and $PM_{2.5}$ mortality risk estimates. The estimated monetized climate benefits are $1 million in 2021 (using a 3 percent discount rate) and $330 million in 2025 (using a 3 percent discount rate). We present the costs and benefits for the years 2021 through 2040 at real discount rates of 3 and 7 percent in Table 7-4.

EPA calculates the net benefits of the rule by subtracting the estimated compliance costs from the estimated benefits in 2021, 2025, and 2030. The benefits include those to public health and climate. The annual net benefits of the rule in 2021 (in 2016$) are approximately $230 and $1,900 million using a 3 percent real discount rate. The annual net benefits of the rule in 2025 are approximately $650 and $2,700 using a 3 percent real discount rate. The annual net benefits of the rule in 2030 are approximately $650 and $2,900 million using a 3 percent real discount rate. Table 7-1 presents a summary of the health benefits, climate benefits, costs, and net benefits of the rule and the more and less stringent alternatives for 2021. Table 7-2 presents a summary of these impacts for the Revised CSAPR Update and the more and less stringent alternatives for 2025. Table 7-3 presents a summary of these impacts for the rule and the more and less stringent alternatives for 2030.

Table 7-1. Benefits, Costs, and Net Benefits of the Final Rule and More and Less Stringent Alternatives for 2021 for the U.S. (millions of 2016$) [a,b,c]

	Final Rule	More Stringent Alternative	Less Stringent Alternative
Health Benefits (3%)	$230 and $1,900	$260 and $1,900	$20 and $190
Climate Benefits (3%)	$1	$2	$1
Total Benefits	$230 and $1,900	$260 and $1,900	$20 and $190
Costs	$5	$5	$2
Net Benefits	**$230 and $1,900**	**$260 and $1,900**	**$20 and $190**
Health Benefits (7%)	$200 and $1,700	$200 and $1,700	$20 and $170
Climate Benefits (3%)	$1	$2	$1
Total Benefits	$200 and $1,700	$200 and $1,700	$20 and $170
Costs	$5	$5	$2
Net Benefits	**$200 and $1,700**	**$200 and $1,700**	**$20 and $170**

[a] We focus results to provide a snapshot of costs and benefits in 2021, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Benefits include those related to public health and climate. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CO_2 at a 3 percent discount rate, but the Agency does not have a single central SC-CO_2 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates; the additional benefit estimates range from $0.24 million to $2.31 million in 2021 for the finalized option. Please see Table 5-9 for the full range of SC-CO_2 estimates. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. The costs presented in this table are 2021 annual estimates for each alternative analyzed.
[c] Rows may not appear to add correctly due to rounding.

Table 7-2. Benefits, Costs, and Net Benefits of the Final Rule and More and Less Stringent Alternatives for 2025 for the U.S. (millions of 2016$) [a,b,c]

	Final Rule	More Stringent Alternative	Less Stringent Alternative
Health Benefits (3%)	$320 and $2,400	$540 and $4,200	$20 and $200
Climate Benefits (3%)	$330	$770	$250
Total Benefits	$650 and $2,700	$1,300 and $5,000	$270 and $450
Costs	$2	$4	-$15
Net Benefits	**$650 and $2,700**	**$1,300 and $5,000**	**$280 and $460**
Health Benefits (7%)	$290 and $2,200	$490 and $3,800	$20 and $170
Climate Benefits (3%)	$330	$770	$250
Total Benefits	$620 and $2,500	$1,300 and $4,600	$270 and $420
Costs	$2	$4	-$15
Net Benefits	**$620 and $2,500**	**$1,300 and $4,500**	**$280 and $430**

[a] We focus results to provide a snapshot of costs and benefits in 2025, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Benefits include those related to public health and climate. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon ($SC\text{-}CO_2$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95^{th} percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average $SC\text{-}CO_2$ at a 3 percent discount rate, but the Agency does not have a single central $SC\text{-}CO_2$ point estimate. We emphasize the importance and value of considering the benefits calculated using all four $SC\text{-}CO_2$ estimates; the additional benefit estimates range from $109 million to $1,011 million in 2025 for the finalized option. Please see Table 5-9 for the full range of $SC\text{-}CO_2$ estimates. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. The costs presented in this table are 2025 annual estimates for each alternative analyzed.
[c] Rows may not appear to add correctly due to rounding.

Table 7-3. Benefits, Costs, and Net Benefits of the Final Rule and More and Less Stringent Alternatives for 2030 for the U.S. (millions of 2016$) [a,b,c]

	Final Rule	More Stringent Alternative	Less Stringent Alternative
Health Benefits (3%)	$340 and $2,600	$590 and $4,600	$30 and $210
Climate Benefits (3%)	$370	$940	$270
Total Benefits	$710 and $3,000	$1,500 and $5,500	$300 and $480
Costs	$64	$32	$67
Net Benefits	**$650 and $2,900**	**$1,500 and $5,500**	**$230 and $410**
Health Benefits (7%)	$330 and $2,500	$560 and $3,900	$20 and $180
Climate Benefits (3%)	$370	$940	$270
Total Benefits	$700 and $2,900	$1500 and $4,800	$290 and $450
Costs	$64	$32	$67
Net Benefits	**$640 and $2,800**	**$1,500 and $4,800**	**$220 and $380**

[a] We focus results to provide a snapshot of costs and benefits in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] Benefits include those related to public health and climate. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon ($SC\text{-}CO_2$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average $SC\text{-}CO_2$ at a 3 percent discount rate, but the Agency does not have a single central $SC\text{-}CO_2$ point estimate. We emphasize the importance and value of considering the benefits calculated using all four $SC\text{-}CO_2$ estimates; the additional benefit estimates range from $128 million to $1,146 million in 2030 for the finalized option. Please see Table 5-9 for the full range of $SC\text{-}CO_2$ estimates. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. The costs presented in this table are 2030 annual estimates for each alternative analyzed.
[c] Rows may not appear to add correctly due to rounding.

As part of fulfilling analytical guidance with respect to E.O. 12866, EPA presents estimates of the present value (PV) of the benefits and costs over the twenty-year period 2021 to 2040. To calculate the present value of the social net-benefits of the Revised CSAPR Update, annual benefits and costs are discounted to 2021 at 3 percent and 7 discount rates as directed by OMB's Circular A-4. The EPA also presents the equivalent annualized value (EAV), which represents a flow of constant annual values that, had they occurred in each year from 2021 to 2040, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates mentioned earlier in the RIA.

For the twenty-year period of 2021 to 2040, the PV of the net benefits, in 2016$ and discounted to 2021, is $8,800 and $41,000 million when using a 3 percent discount rate and $7,300 and $29,000 million when using a 7 percent discount rate. The EAV is $590 and $2,800 million per year when using a 3 percent discount rate and $570 and $2,700 million when using a 7 percent discount rate. The comparison of benefits and costs in PV and EAV terms for the rule can be found in Table 7-4. Estimates in the table are presented as rounded values and based on air quality simulations run for years 2021 and 2024.

Table 7-4. Summary of Annual Values, Present Values and Equivalent Annualized Values for the 2021-2040 Timeframe for Estimated Compliance Costs, Benefits, and Net Benefits for the Final Rule (millions of 2016$, discounted to 2021)[a,b]

	Health Benefits		Climate Benefits[c]	Cost[d]		Net Benefits	
	3%	7%	3%	3%	7%	3%	7%
2021*	$230 and $1,900	$200 and $1,700	$1	$5		$230 and $1,900	$200 and $1,700
2022	$230 and $2,000	$210 and $1,600	$140	$19		$350 and $2,100	$330 and $1,700
2023	$230 and $2,000	$210 and $1,600	$290	$19		$500 and $2,300	$480 and $1,900
2024*	$310 and $2,400	$280 and $2,100	$310	$2		$620 and $2,700	$590 and $2,400
2025	$320 and $2,400	$290 and $2,200	$330	$2		$650 and $2,700	$620 and $2,500
2026	$330 and $2,500	$290 and $2,200	$340	$1		$670 and $2,800	$630 and $2,500
2027	$320 and $2,400	$300 and $2,300	$350	$0		$670 and $2,800	$650 and $2,700
2028	$330 and $2,500	$310 and $2,400	$360	$66		$620 and $2,800	$600 and $2,700
2029	$330 and $2,500	$320 and $2,400	$360	$65		$630 and $2,800	$620 and $2,700
2030	$340 and $2,600	$330 and $2,500	$370	$64		$650 and $2,900	$640 and $2,800
2031	$350 and $2,600	$340 and $2,600	$350	$64		$640 and $2,900	$630 and $2,900
2032	$360 and $2,700	$350 and $2,600	$330	$63		$630 and $3,000	$620 and $2,900
2033	$350 and $2,600	$360 and $2,700	$310	$18		$640 and $2,900	$650 and $3,000
2034	$360 and $2,700	$370 and $2,800	$290	$18		$630 and $3,000	$640 and $3,100
2035	$370 and $2,800	$380 and $2,800	$270	$18		$620 and $3,100	$630 and $3,100
2036	$370 and $2,800	$390 and $2,900	$290	$18		$640 and $3,100	$660 and $3,200
2037	$380 and $2,900	$400 and $3,000	$300	$18		$660 and $3,200	$680 and $3,300
2038	$370 and $2,800	$410 and $3,100	$310	$9		$670 and $3,100	$710 and $3,400
2039	$380 and $2,800	$430 and $3,200	$330	$9		$700 and $3,100	$750 and $3,500
2040	$380 and $2,900	$440 and $3,200	$340	$9		$710 and $3,200	$770 and $3,500
PV 2021-2040	**$4,800 and $37,000**	**$3,200 and $25,000**	**$4,400**	**$370**	**$260**	**$8,800 and $41,000**	**$7,300 and $29,000**
EAV 2021 - 2040	**$320 and $2,500**	**$300 and $2,400**	**$290**	**$25**	**$25**	**$590 and $2,800**	**$570 and $2,700**

[a] Rows may not appear to add correctly due to rounding. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] The annualized present value of costs and benefits are calculated over a 20-year period from 2021 to 2040.
[c] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the social cost of carbon (SC-CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For purposes of this table, we show the benefits

associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CO_2 estimates. As discussed in Chapter 5, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

[d] The costs presented in this table are consistent with the costs presented in Chapter 4, Table 4-6. To estimate these annualized costs, EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. Annual costs were calculated using a 4.25% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

*Year in which air quality was simulated. Ozone air quality was simulated in 2021 and 2024 while the formation of $PM_{2.5}$ was simulated only in 2024. Health benefits for all other years were linearly extrapolated or interpolated from model-simulated air quality in these years. This method assumes that ozone and $PM_{2.5}$ formation reaches a steady state beyond 2024 and may create increasing uncertainty in the benefits estimates the farther into the future estimates are extrapolated. Benefits calculated as value of avoided: $PM_{2.5}$-attributable deaths (quantified using a concentration-response relationship from the Di et al. 2017 study); Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2017 study); and $PM_{2.5}$ and ozone-related morbidity effects.

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