Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review

EPA-452/R-21-003
October 2021

Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review

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ACKNOWLEDGEMENTS

In addition to U.S. EPA staff from the Office of Air and Radiation, personnel from SC&A contributed data and analysis to this document.

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1 EXECUTIVE SUMMARY

1.1 Introduction

This action first proposes to amend existing crude oil and natural gas new source performance standards (NSPS) under the Clean Air Act (CAA) section 111(b). Second, this action proposes new NSPS for the crude oil and natural gas source category. Third, this action proposes emissions guidelines (EG) under CAA section 111(d) which will inform states on the development, submittal, and implementation of state plans to establish performance standards for existing crude oil and natural gas sources. This proposal responds to the President's Executive Order (EO) 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." This document presents the regulatory impact analyses (RIA) for the both the NSPS and EG components of this proposed action. More detail on each of the proposed actions follows.

NSPS OOOO and NSPS OOOOa: This rulemaking proposes to implement the regulatory changes resulting from the June 30, 2021 joint resolution of disapproval of the final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review," 85 FR 57018 (September 14, 2020) (2020 Policy Rule), enacted pursuant to the Congressional Review Act (CRA), and to address other issues resulting from the final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," 85 FR 57398 (September 15, 2020) (2020 Technical Rule). The EPA is proposing amendments to its 2012 NSPS titled "Subpart OOOO-Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After August 23, 2011, and on or Before September 18, 2015" (2012 NSPS OOOO) and to its 2016 NSPS OOOOa (as amended by 2020 Technical Rule).

NSPS OOOOb: With respect to the NSPS, the EPA first is proposing the review and revision of the standards of performance for the Crude Oil and Natural Gas source category published in 2016 and amended in 2020. Based on its review, the EPA is proposing to update, strengthen, and expand the current requirements under CAA section 111(b) for methane and VOC emissions from affected sources. These proposed standards of performance will be in a new subpart

OOOOb (NSPS OOOOb). The proposal for NSPS OOOOb also includes standards for emission sources previously not regulated under the 2016 NSPS OOOOa.

EG OOOOc: Pursuant to CAA 111(d), the EPA is proposing the first nationwide emission guidelines for states to limit methane pollution from designated facilities in the crude oil and natural gas source category. These emission guidelines that are being proposed in this rulemaking will be in a new subpart, specifically 40 CFR part 60, subpart OOOOc (EG OOOOc). The emission guidelines are designed to inform states in the development, submittal, and implementation of state plans that establish standards of performance for GHGs from their designated facilities in the Crude Oil and Natural Gas source category.

1.2 Legal and economic basis for this rulemaking

In this section, we summarize the statutory requirements in the Clean Air Act that serve as the legal basis for the proposed rule and the economic theory that supports environmental regulation as a mechanism to enhance social welfare. The Clean Air Act requires the EPA to prescribe regulations for new and existing sources. In turn, those regulations attempt to address negative externalities created when private entities fail to internalize the social costs of air pollution.

1.2.1 Statutory Requirements

Clean Air Act section 111, which Congress enacted as part of the 1970 Clean Air Act Amendments, establishes mechanisms for controlling emissions of air pollutants from stationary sources. This provision requires the EPA to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds “causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.” The EPA has listed more than 60 stationary source categories under this provision. Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish “standards of performance” for emissions of air pollutants from new sources in the source categories. Under section 111(b), EPA identifies the “best system of emission reduction” (BSER) that has been adequately demonstrated to control emissions of a particular pollutant from a particular type of source and sets a standard for new sources based on the application of that BSER. These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

When the EPA establishes NSPS for sources in a source category under CAA section 111(b), the EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the NAAQS or regulated under the CAA section 112 requirements for hazardous air pollutants (HAP). CAA section 111(d)'s mechanism for regulating existing sources differs from the one that CAA section 111(b) provides for new sources because CAA section 111(d) contemplates states submitting plans that establish "standards of performance" for the affected sources and contain other measures to implement and enforce those standards.

"Standards of performance" are defined under CAA section 111(a)(1) as standards for emissions that reflect the emission limitation achievable from the "best system of emission reduction," considering costs and other factors, that "the Administrator determines has been adequately demonstrated." Under section 111(d), EPA determines the BSER, but, unlike with new sources under 111(b), the states are the entities that establish performance standards. CAA section 111(d)(1) grants states the authority, in applying a standard of performance, to take into account the source's remaining useful life and other factors.

Under CAA section 111(d), a state must submit its plan to the EPA for approval, and the EPA must approve the state plan if it is "satisfactory." If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for that state. Once a state receives the EPA's approval of its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved State Implementation Plan (SIP) under the Act.

1.2.2 Market Failure

Many regulations are promulgated to correct market failures, which otherwise lead to a suboptimal allocation of resources within the free market. Air quality and pollution control regulations address "negative externalities" whereby the market does not internalize the full opportunity cost of production borne by society as public goods such as air quality are unpriced.

While recognizing that optimal social level of pollution may not be zero, methane and VOC emissions impose costs on society, such as negative health and welfare impacts, that are not reflected in the market price of the goods produced through the polluting process. For this regulatory action the goods produced are crude oil and natural gas. If crude oil and natural gas producers pollute the atmosphere when extracting and, in the case of natural gas, processing and transporting products, the social costs will not be borne by the polluting firm but rather by society as a whole. Thus, the producer is imposing a negative externality, or a social cost of emissions, on society. The equilibrium market price of crude oil and natural gas may fail to incorporate the full opportunity cost to society of these products. Consequently, absent a regulation on emissions, producers will not internalize the social cost of emissions and social costs will be higher as a result. This regulation will work towards addressing this market failure by causing affected producers to begin internalizing the negative externality associated with methane and VOC emissions.

1.3 Baseline and Regulatory Requirements

The impacts of regulatory actions are evaluated relative to a baseline that represents the world without the regulatory action. We present results for the proposed NSPS OOOOb and EG OOOOc. Throughout this document, we focus the analysis on the proposed requirements that result in quantifiable compliance cost or emissions changes compared to the baseline. The baseline for the proposal incorporates changes to regulatory requirements induced by the Congressional Review Act (CRA) resolution that disapproved the 2020 Policy Rule. We do not analyze the regulatory impacts of all proposed requirements because we either do not have sufficient data or because it is assumed the provisions would not result in compliance cost or emissions impacts; in these instances, we qualitatively discuss the proposed requirements.

Compared to the analysis presented in the previous oil and natural gas sector NSPS RIAs, this analysis reflects updated assumptions based on new information on existing and projected source counts, model plant emissions and control costs, natural gas prices, and state and local regulations that have been promulgated. The updated baseline represents the EPA's best assessment of the current and future state of the industry absent the requirements proposed in this action.

Table 1-1 and Table 1-2 summarize the sources affected by this action and their respective regulatory requirements in the baseline. In Table 1-2, requirements in the baseline differ depending on when sources were constructed relative to previous NSPS proposal dates. We define pre- and post-KKK as having construction dates prior to and after January 20, 1984, respectively. The dividing dates for pre- and post-OOOO and pre- and post-OOOOa are August 23, 2011 and September 18, 2015, respectively.

Table 1-1 NSPS OOOOb Emissions Sources, Baseline Requirements, and Requirements under the Primary Proposed Option

Source	BSER: In the Baseline	BSER: Under the Proposal
Fugitive Emissions/Equipment Leaks		
Well Sites		
Bin 1: 0 – 3 tpy	Semiannual OGI	Verify baseline methane emissions[a]
Bin 2: 3 – 8 tpy	Semiannual OGI	Quarterly OGI[b]
Bin 3: 8+ tpy	Semiannual OGI	Quarterly OGI
Gathering and Boosting Stations	Quarterly OGI	Quarterly OGI
Transmission and Storage Compressor Stations	Quarterly OGI	Quarterly OGI
Natural gas processing plants	NSPS Subpart VVa	Bimonthly OGI
Pneumatic Pumps		
Well Sites	Route to control	Route to control
Gathering and Boosting Stations	No requirement	Route to control
Pneumatic Controllers		
Well Sites	Emissions limit	Non-emitting or emissions limit[c]
Gathering and Boosting Stations	Emissions limit	Non-emitting or emissions limit[c]
Transmission and Storage Compressor Stations	Emissions limit	Non-emitting or emissions limit[c]
Natural gas processing plants	Instrument air system	Instrument air system
Reciprocating Compressors		
Gathering and Boosting Stations	Rod-packing changeout on fixed schedule	Monitoring with replacement threshold for rod-packing
Natural gas processing plants	Rod-packing changeout on fixed schedule	Monitoring with replacement threshold for rod-packing
Transmission and Storage Compressor Stations	Rod-packing changeout on fixed schedule	Monitoring with replacement threshold for rod-packing
Centrifugal Compressors		
Gathering and Boosting Stations	No requirement	Route to control
Natural gas processing plants	Route to control	Route to control
Transmission and Storage Compressor Stations	Route to control	Route to control
Liquids Unloading		
Well Sites	No requirement	Zero emissions or best management practices[d]
Storage Vessels		
PTE ≥ 6 tpy VOC	95% control, affected facility is the tank	95% control, affected facility is the tank battery
PTE < 6 tpy VOC	No requirement	No requirement

[a] Operators are required to perform a survey to verify that actual site emissions are reflected in the baseline calculation. This survey reflects BSER but is not costed in the analysis.
[b] The proposed rule includes co-proposals for fugitive emissions monitoring frequency at well sites with calculated emissions between 3 and 8 tpy of methane. The BSER for the primary proposal, which is the central policy scenario in this analysis, is quarterly OGI. The BSER for the co-proposal is semiannual OGI.
[c] Operators of sites are required to install non-emitting systems for controllers except for sites located in Alaska where onsite power is not available. Instead, operators of those sites are prohibited from installing continuous-bleed controllers that exceed an emissions limit, except in cases where failing to do so would create a safety concern.
[d] Under the proposed regulation, liquids unloading events at well sites would be treated as modifications that would trigger the NSPS OOOOb requirements for liquids unloading only. The proposed regulation requires liquids

unloading events to be zero-emitting unless technical infeasibilities exist, in which case the regulation requires that best management practices be adopted.

Table 1-2 EG OOOOc Emissions Sources, Baseline Requirements, and Requirements under the Primary Proposed Option

	BSER	
Source	**In the Baseline**	**Under the Proposal**
Fugitive Emissions/Equipment Leaks		
Well Sites		
Bin 1: 0 – 3 tpy	Pre-OOOOa: no requirement Post-OOOOa: semiannual OGI	Verify baseline methane emissions[a]
Bin 2: 3 – 8 tpy		Quarterly OGI[b]
Bin 3: 8+ tpy		Quarterly OGI
Gathering and Boosting Stations	Pre-OOOOa: no requirement Post-OOOOa: quarterly OGI	Quarterly OGI
Transmission and Storage Compressor Stations		
Natural gas processing plants	Pre-KKK: no requirement Post-KKK and Pre-OOOO: NSPS Subpart VV Post-OOOO: NSPS Subpart VVa	Bimonthly OGI
Pneumatic Pumps		
Well Sites	Pre-OOOOa: no requirement Post-OOOOa: route to control	Route to control
Gathering and Boosting Stations	No requirement	
Pneumatic Controllers		
Well Sites	Pre-OOOO: no requirement Post-OOOO: emissions limit	Non-emitting or emissions limit[c]
Gathering and Boosting Stations		
Transmission and Storage Compressor Stations	Pre-OOOOa: no requirement Post-OOOOa: emissions limit	
Natural gas processing plants	Pre-OOOO: no requirement Post-OOOO: instrument air system	Instrument air system
Reciprocating Compressors		
Gathering and Boosting Stations	Pre-OOOO: no requirement Post-OOOO: rod-packing changeout on fixed schedule	Monitoring with replacement threshold for rod-packing
Natural gas processing plants		
Transmission and Storage Compressor Stations	Pre-OOOOa: no requirement Post-OOOOa: rod-packing changeout on fixed schedule	
Centrifugal Compressors		
Gathering and Boosting Stations	No requirement	Route to control
Natural gas processing plants	Pre-OOOO: no requirement Post-OOOO: route to control	
Transmission and Storage Compressor Stations	Pre-OOOOa: no requirement Post-OOOOa: route to control	
Storage Vessels		
PTE ≥ 20 tpy CH_4	Pre-OOOO: no requirement Post-OOOO: 95% control, affected facility is the tank[d]	95% control, affected facility is the tank battery[d]
PTE < 20 tpy CH_4 and ≥ 6 tpy VOC		No requirement
PTE < 20 tpy CH_4 and < 6 tpy VOC	No requirement	

[a] Operators are required to perform a survey to verify that actual site emissions are reflected in the baseline calculation. This survey reflects BSER but is not costed in the analysis. Post-OOOOa and pre-OOOOb well sites are subject to the NSPS OOOOa requirements as well as the EG OOOOc requirements, and so well sites in methane emissions Bin 1 would still be required to perform semiannual OGI if the proposed regulation is finalized.
[b] The proposed rule includes co-proposals for fugitive emissions monitoring frequency at well sites with calculated emissions between 3 and 8 tpy of methane. The BSER for the primary proposal, which is the central policy scenario in this analysis, is quarterly OGI. The BSER for the co-proposal is semiannual OGI.
[c] Operators of sites are required to install non-emitting systems for controllers except for sites located in Alaska where onsite power is not available. Instead, operators of those sites are prohibited from installing continuous-bleed controllers that exceed an emissions limit, except in cases where failing to do so would create a safety concern.
[d] As an example, a post-OOOO tank battery with 4 tanks each emitting 5 tons per year VOC would not be required to achieve 95 percent control in the baseline, since the affected facility is the individual tank and emissions fall below the 6 tons per year VOC threshold. Under the proposed rule, the same tank battery would be required to achieve 95 percent control, as the affected facility is the tank battery, which in this example emits 20 tons per year of VOC, exceeding the 6 tons per year VOC threshold.

1.4 Methodology

The net benefits analysis summarized in this RIA reflects a nationwide engineering analysis of compliance cost and emissions reductions, of which there are two main components: activity data and information on control measures. The activity data represents estimates of the counts of affected facilities over time, and the control measure information includes data on costs and control efficiencies for typical facilities. Both components are described briefly below, with more detailed information provided in Section 2.

The first component is activity data for a set of representative or model plants for each regulated facility.[1] For each regulated facility type, unique model plants are defined across each applicable industry segment and regulatory vintage.[2] Moreover, where more detailed data exists, several model plants are constructed to capture important sources of heterogeneity within a regulated facility type and segment (e.g., oil versus natural gas wells). Using a variety of data sources and some basic assumptions on retirement rates, we generate projections of counts of regulated facilities into the future.

The regulated facility projections are combined with information on control options, including capital and annual operations and maintenance costs and control efficiencies. Information on

[1] Regulated facilities include well site fugitives, gathering and boosting station fugitives, transmission and storage compressor station fugitives, natural gas processing plant equipment leaks, pneumatic pumps, pneumatic controllers, reciprocating compressors, centrifugal compressors, liquids unloading, and storage vessels.
[2] Industry segments include production, gathering and boosting, processing, transmission, and storage. Regulatory vintages include sources constructed prior to proposal dates for NSPS OOOO, after NSPS OOOO and before NSPS OOOOa, after NSPS OOOOa and before NSPS OOOOb, and after NSPS OOOOb.

control options is derived from the analysis underpinning the BSER determinations. Impacts are calculated by setting parameters on how and when affected facilities are assumed to respond to a regulatory regime, multiplying activity data by model plant cost and emissions estimates, differencing from the baseline scenario, and then summing to the desired level of aggregation. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted in production or sold. Where applicable, we present projected compliance costs with and without the projected revenues from product recovery.

For the analysis, we calculate the cost and emissions impacts of the proposed NSPS OOOOb and EG OOOOc from 2023 to 2035. The initial analysis year is 2023 as we assume the proposed rule will be finalized toward the end of 2022. The NSPS OOOOb will take effect immediately and impact sources constructed after publication of the proposed rule. We assume the EG OOOOc will take longer to go into effect as states will need to develop implementation plans in response to the rule and have them approved by the Agency. We assume that this process will take three years, and so EG OOOOc impacts will begin in 2026. The final analysis year is 2035, which allows us to present ten years of regulatory impacts after state plans under the EG OOOOc are assumed to take effect.

1.5 Summary of Key Results

A summary of the key results is shown below. All dollar estimates are in 2019 dollars. Also, all compliance costs, emissions changes, and benefits are estimated for the years 2023 to 2035 relative to a baseline without the proposed NSPS OOOOb and EG OOOOc.

Table 1-3 summarizes the emissions reductions associated with the proposed standards over the 2023 to 2035 period for the NSPS OOOOb, the EG OOOOc, and the NSPS OOOOb and EG OOOOc combined. The emissions reductions are estimated by multiplying the source-level emissions reductions associated with each applicable control and facility type by the number of affected sources of that facility type. We present methane emissions in both short tons and CO_2 equivalents (CO_2 Eq.) using a global warming potential of 25.[3]

[3] Global warming potential is a measure that allows comparisons of the global warming impacts of different greenhouse gases. Specifically, it is a measure of how much energy the emission of 1 ton of a gas will absorb over a given period of time, relative to the emission of 1 ton of carbon dioxide (CO_2).

Table 1-3 Projected Emissions Reductions under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035

Proposal	Emissions Changes			
	Methane (million short tons)	VOC (million short tons)	HAP (million short tons)	Methane (million metric tons CO_2 Eq. using GWP=25)
NSPS OOOOb	6.1	1.8	0.07	140
EG OOOOc	35	10.0	0.41	790
Total	**41**	**12**	**0.48**	**920**

Note: Totals may not sum due to independent rounding. Numbers rounded to two significant digits unless otherwise noted. To convert from short tons to metric tons, multiply the short tons by 0.907. Alternatively, to convert metric tons to short tons, multiply metric tons by 1.102.

Table 1-4, Table 1-5, and Table 1-6 present results for the primary proposal for the NSPS OOOOb, EG OOOOc, and NSPS OOOOb and EG OOOOb combined, respectively. Each table presents the present value (PV) and equivalent annual value (EAV), estimated using discount rates of 3 and 7 percent, of the changes in quantified benefits, costs, and net benefits, as well as the emissions reductions relative to the baseline. These values reflect an analytical time horizon of 2023 to 2035, are discounted to 2021, and presented in 2019 dollars. We present the total compliance costs, the value of product recovery generated by the capture of natural gas, and the net compliance costs, which treats the value of product recovery as an offset to the compliance costs.[4] The table includes consideration of the non-monetized benefits associated with the emissions reductions projected under this proposal.

[4] Under this proposal, over 90 percent of revenue from the sale of captured natural gas is projected to be earned by operators in the production and processing segments of the industry, where we assume that the operators own the natural gas and will receive the financial benefit from the captured natural gas. The remainder of the captured natural gas is captured within the transmission and storage segment, where operators do not typically own the natural gas they transport; rather, they receive payment for the transportation service they provide. In the RIA, we treat these revenues as an offset to projected compliance costs, while the revenues may also be considered as a benefit of the regulatory action. However, regardless of whether the revenue from capture of natural gas is considered a compliance cost offset or a benefit, the net benefits are equivalent.

Table 1-4 Projected Benefits, Compliance Costs, and Emissions Reductions for the Primary Proposed NSPS OOOOb Option, 2023–2035 (million 2019$)[a]

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[b]	$8,300	$780	$8,300	$780
	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Net Compliance Costs	($160)	($15)	$75	$9
Compliance Costs	$670	$63	$660	$79
Value of Product Recovery	$840	$79	$590	$70
Net Benefits	$8,400	$790	$8,200	$770
Non-Monetized Benefits	Climate and ozone health benefits from reducing 6.1 million short tons of methane from 2023 to 2035 $PM_{2.5}$ and ozone health benefits from reducing 1.8 million short tons of VOC from 2023 to 2035[c] HAP benefits from reducing 70 thousand short tons of HAP from 2023 to 2035 Visibility benefits Reduced vegetation effects			

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane ($SC-CH_4$) (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 $SC-CH_4$ at a 3 percent discount rate, but the Agency does not have a single central $SC-CH_4$ point estimate. We emphasize the importance and value of considering the benefits calculated using all four $SC-CH_4$ estimates; the present value (and equivalent annual value) of the additional benefit estimates ranges from $3.3 billion to $22 billion ($350 million to $2.1 billion) over 2023 to 2035 for the proposed option. Please see Table 3-5 and Table 3-7 for the full range of $SC-CH_4$ estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. All net benefits are calculated using climate benefits discounted at 3 percent.
[c] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix B.

Table 1-5 Projected Benefits, Compliance Costs, and Emissions Reductions for the Primary Proposed EG OOOOc Option, 2023–2035 (million 2019$)[a]

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[b]	$47,000	$4,400	$47,000	$4,400
	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Net Compliance Costs	$7,400	$690	$6,300	$750
Compliance Costs	$12,000	$1,100	$9,600	$1,100
Value of Product Recovery	$4,700	$440	$3,300	$400
Net Benefits	$40,000	$3,700	$41,000	$3,700
Non-Monetized Benefits	Climate and ozone health benefits from reducing 35 million short tons of methane from 2023 to 2035 $PM_{2.5}$ and ozone health benefits from reducing 10 million short tons of VOC from 2023 to 2035[c] HAP benefits from reducing 410 thousand short tons of HAP from 2023 to 2035 Visibility benefits Reduced vegetation effects			

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane (SC-CH_4) (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-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the present value (and equivalent annual value) of the additional benefit estimates ranges from $19 billion to $130 billion ($2.0 billion to $12 billion) over 2023 to 2035 for the proposed option. Please see Table 3-5 and Table 3-7 for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. All net benefits are calculated using climate benefits discounted at 3 percent.
[c] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix B.

Table 1-6 Projected Benefits, Compliance Costs, and Emissions Reductions for the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (million 2019$)[a]

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[b]	$55,000	$5,200	$55,000	$5,200
	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Net Compliance Costs	$7,200	$680	$6,300	$760
Compliance Costs	$13,000	$1,200	$10,000	$1,200
Value of Product Recovery	$5,500	$520	$3,900	$470
Net Benefits	$48,000	$4,500	$49,000	$4,500
Non-Monetized Benefits	Climate and ozone health benefits from reducing 41 million short tons of methane from 2023 to 2035 $PM_{2.5}$ and ozone health benefits from reducing 12 million short tons of VOC from 2023 to 2035[c] HAP benefits from reducing 480 thousand short tons of HAP from 2023 to 2035 Visibility benefits Reduced vegetation effects			

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane ($SC\text{-}CH_4$) (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 $SC\text{-}CH_4$ at a 3 percent discount rate, but the Agency does not have a single central $SC\text{-}CH_4$ point estimate. We emphasize the importance and value of considering the benefits calculated using all four $SC\text{-}CH_4$ estimates; the present value (and equivalent annual value) of the additional benefit estimates ranges from $22 billion to $150 billion ($2.4 billion to $14 billion) over 2023 to 2035 for the proposed option. Please see Table 3-5 and Table 3-7 for the full range of $SC\text{-}CH_4$ estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. All net benefits are calculated using climate benefits discounted at 3 percent.
[c] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix B of the RIA.

1.6 Organization of RIA

Section 2 describes the projected compliance cost and emissions impacts from the proposal, including the PV and EAV of the projected costs over the 2023 to 2035 period and the associated EAV. Section 3 describes the projected climate benefits resulting from this proposal, including the PV and EAV of the projected climate benefits over the 2023 to 2035 period. Section 3 additionally considers the potential beneficial climate, health, and welfare impacts that could not be quantified. Section 4 describes the economic impact and distributional analysis associated with the proposed rule. The economic impact and distributional analysis section includes analysis of oil and natural gas market impacts, environmental justice, small entities, and employment. Section 5 compares the projected benefits and compliance cost reductions of this action, as well as a summary of the net benefits with consideration of non-monetized benefits. Section 5 also highlights uncertainties and limitations of the analysis. The RIA includes three appendices, which provide further detail on the projection of affected sources, a screening analysis of monetized ozone benefits from VOC reductions, and additional information on the environmental justice analysis.

2 PROJECTED COMPLIANCE COSTS AND EMISSIONS REDUCTIONS

In this section, we present estimates of the projected engineering compliance costs and emissions reductions associated with the proposed rule for the 2023 to 2035 period. These estimates are generated by combining the model plant-level cost and emissions reductions used in the BSER analysis with activity data projections based on a combination of historical trends and third-party projections. The methods and assumptions used to construct the activity data projections are also documented in this section.

2.1 Emissions Sources and Regulatory Requirements Analyzed in this RIA

A series of emissions sources and controls were evaluated as part of the proposed NSPS OOOOb and EG OOOOc review. Section 2.1.1 provides a basic description of emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic analysis. Section 2.1.2 describes the regulatory choices within the proposed NSPS OOOOb and EG OOOOc that are examined in this RIA. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant sections within the Technical Support Document (TSD), hereafter referred to as the 2021 TSD.[5]

2.1.1 Emissions Sources

The section provides brief descriptions of the emissions sources subject to the requirements in the proposed NSPS OOOOb and EG OOOOc. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant sections within the 2021 TSD.

Fugitive Emissions: There are several potential sources of fugitive emissions throughout the crude oil and natural gas production source category. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions.

[5] U.S. EPA. 2021e. *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG)*. Available at https://www.regulations.gov/ under Docket No. EPA-HQ-OAR-2021-0317.

Poor maintenance or operating practices, such as improperly reseated pressure relief valves (PRVs) or worn gaskets on thief hatches on controlled storage vessels are also potential causes of fugitive emissions. Additional sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as PRVs, pump seals, valves or controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, insofar as the natural gas discharged from the device's vent is not considered a fugitive emissions (e.g., an intermittent pneumatic controller that is venting continuously).

Pneumatic Controllers: Pneumatic controllers are devices used to regulate a variety of physical parameters, or process variables, using air or gas pressure to control the operation of mechanical devices, such as valves. The valves, in turn, control process conditions such as levels, temperatures and pressures. When a pneumatic controller identifies the need to alter a process condition, it will open or close a control valve. In many situations across all segments of the oil and natural gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate or control the valve. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control.

Pneumatic controllers can be categorized based on the emissions pattern of the controller. Some controllers are designed to have the supply-gas provide the required pressure to power the end-device, and the excess amount of gas is emitted. The emissions of this excess gas are referred to as "bleed," and this bleed occurs continuously. Controllers that operate in this manner are referred to as "continuous bleed" pneumatic controllers. These controllers can be further categorized based on the amount of bleed they are designed to have. Those that have a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh) are referred to as "low bleed," and those with a bleed rate of greater than 6 scfh are referred to as "high bleed." Another type of controller is designed to release gas only when the process parameter needs to be adjusted by opening or closing the valve, and there is no vent or bleed of gas to the atmosphere when the valve is stationary. These types of controllers are referred to as "intermittent vent" pneumatic controllers. A third type of controller releases gas to a downstream pipeline instead of the atmosphere. These "closed loop" types of controllers can be used in applications with very low pressure.

Pneumatic Pumps: Most pneumatic pumps fall into two main types: diaphragm pumps, generally used for heat tracing and plunger/piston pumps, generally used for chemical and methanol injection. The pneumatic pump may use natural gas or another gas to drive the pump. These pumps can also be electrically powered. "Non-natural-gas driven" pneumatic pumps can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Because these devices are not natural gas-driven, they do not directly release natural gas or methane emissions. However, these systems have other energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient and reliable enough to power an air control system.

Reciprocating Compressors: In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder.

Centrifugal Compressors: Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Some centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and adsorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process. Off gassing of entrained natural gas from wet seal centrifugal compressors is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process. Some centrifugal compressors utilize dry seal systems. Dry seal systems minimize leakage by using the opposing force created by hydrodynamic grooves and springs.

Storage vessels: Storage vessels, or storage tanks, in the oil and natural gas sector are used to hold a variety of liquids, including crude oil, condensates, and produced water. Many facilities operate a group of storage vessels, sometimes in series but most often in parallel, used to store the same oil or condensate streams. This group of tanks used to store a common fluid is typically called a tank battery.

Underground crude oil contains many light hydrocarbon gases in solution. When oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons are removed through a series of high-pressure and low-pressure separators. The oil (or condensate or water) from the separator is then directed to a tank battery where it is stored before being shipped off-site. Some light hydrocarbon gases remain dissolved in the oil, condensate, or water because the separator operates at pressures above atmospheric pressure. These dissolved hydrocarbon gases are released from the liquid as vapors, commonly referred to as flash gas, when stored at atmospheric pressures in the tank batteries. Typically, the larger the operating pressure of the separator, the more flash emissions will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions. Lighter crude oils and condensate generally flash more hydrocarbons than heavier crude oils.

In addition to flash gas losses, other hydrocarbons may be emitted from the storage vessels due to working and breathing (or standing) losses. Working losses occur when vapors are displaced due to the emptying and filling of tank batteries. When the liquid level in the tank is lowered, ambient air is drawn into the tank’s headspace. Some hydrocarbons from the liquid will volatilize into the headspace to reach equilibrium with the new headspace gas. When the liquid level in the tank is increased, it will expel the saturated headspace gas into the atmosphere. Breathing losses are the release of gas associated with daily temperature fluctuations when the liquid level remains unchanged. As temperatures drop (or atmospheric pressure increases), gas in the headspace contracts, drawing in ambient air. Again, hydrocarbons volatilize into this new gas due to equilibrium effects. As the temperature rises (or atmospheric pressure falls), the gas in the tank's headspace expands, expelling a portion of the hydrocarbon-saturated gas. Working losses increase relative to the "turnover rate" (throughput rate divided by the tank capacity) and are typically much greater than breathing losses.

Liquids Unloading: In new natural gas wells, there is generally sufficient reservoir pressure/gas velocity to facilitate the flow of water and hydrocarbon liquids through the well head and to the separator to the surface along with produced gas. In mature gas wells, the accumulation of liquids in the wellbore can occur when the bottom well pressure/gas velocity approaches the average reservoir pressure (i.e., volumetric average fluid pressure within the reservoir across the areal extent of the reservoir boundaries). This accumulation of liquids can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production (i.e., liquids loading), removal of fluids (i.e., liquids unloading) is required to maintain production. These gas wells therefore often need to remove or "unload" the accumulated liquids so that gas production is not inhibited.

The choice of what liquids unloading technique to employ is based on a well-by-well and reservoir-by-reservoir analysis. To address the complex science and engineering considerations to cover well unloading requirements, many differing technologies, techniques, and practices have been developed to address an individual well's characteristics of the well to manage liquids and maintain production of the well. At the onset of liquids loading, techniques that rely on the reservoir energy are typically used. Eventually a well's reservoir energy is not sufficient to remove the liquids from the well and it is necessary to add energy to the well to continue production. Owners and operators can choose from several techniques to remove the liquids, including manual unloading, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps, intermittent unloading, gas lift (e.g., use of a plunger lift), foam agents and wellhead compression. Each of these methods/procedures removes accumulated liquids and thereby maintains or restores gas production. Although the unloading method employed by an owner or operator can itself be a method that mitigates/eliminates venting of emissions from a liquids unloading event, dictating a particular method to meet a particular well's unloading needs is a production engineering decision.

Equipment Leaks at Gas Plants: The primary sources of equipment leak emissions from natural gas processing plants are pumps, valves, and connectors. The major cause of equipment leak emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. For pumps, emissions are often a result of a seal failure. The large number of valves, pumps, and connectors at natural gas processing plants means emissions from these components can be significant.

Common classifications of equipment at natural gas processing facilities include components in VOC service and in non-VOC service. "In VOC service" is defined as a component containing or in contact with a process fluid that is at least 10 percent VOC by weight or a component "in wet gas service," which is a component containing or in contact with field gas before extraction. "In non-VOC service" is defined as a component in methane service (at least 10 percent methane) that is not also in VOC service.

The most common technique to reduce emissions from equipment leaks is to implement a LDAR program. Implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators, decrease exposure for the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions. The effectiveness of an LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks.

2.1.2 Regulatory Requirements

Table 2-1 and Table 2-2 summarizes the sources affected by this action and their respective regulatory requirements in the baseline. Requirements in the baseline differ depending on when sources were constructed relative to previous NSPS proposal dates. We define pre- and post-KKK as dates prior to and after January 20, 1984, respectively. The dividing dates for pre- and post-OOOO and pre- and post-OOOOa are August 23, 2011 and September 18, 2015, respectively. There are a few proposed requirements that we do not attempt to quantify regulatory impacts for in the RIA, most notably emissions control requirements for piston pumps and associated gas from oil wells. We expect the impacts from those provisions to be small relative to the overall impacts of the proposal. We also do not account for instances in which all or some sources in Alaska are subject to different requirements than those in the rest of the country, both in the baseline due to previous rulemakings and in the proposal; see Section 5.2 for additional discussion.

Table 2-1 NSPS OOOOb Emissions Sources, Baseline Requirements, and Requirements under the Primary Proposed Option

Source	BSER: In the Baseline	BSER: Under the Proposal
Fugitive Emissions/Equipment Leaks		
Well Sites		
Bin 1: 0 – 3 tpy	Semiannual OGI	Verify baseline methane emissions[a]
Bin 2: 3 – 8 tpy	Semiannual OGI	Quarterly OGI[b]
Bin 3: 8+ tpy	Semiannual OGI	Quarterly OGI
Gathering and Boosting Stations	Quarterly OGI	Quarterly OGI
Transmission and Storage Compressor Stations	Quarterly OGI	Quarterly OGI
Natural gas processing plants	NSPS Subpart VVa	Bimonthly OGI
Pneumatic Pumps		
Well Sites	Route to control	Route to control
Gathering and Boosting Stations	No requirement	Route to control
Pneumatic Controllers		
Well Sites	Emissions limit	Non-emitting or emissions limit[c]
Gathering and Boosting Stations	Emissions limit	Non-emitting or emissions limit[c]
Transmission and Storage Compressor Stations	Emissions limit	Non-emitting or emissions limit[c]
Natural gas processing plants	Instrument air system	Instrument air system
Reciprocating Compressors		
Gathering and Boosting Stations	Rod-packing changeout on fixed schedule	Monitoring with replacement threshold for rod-packing
Natural gas processing plants	Rod-packing changeout on fixed schedule	Monitoring with replacement threshold for rod-packing
Transmission and Storage Compressor Stations	Rod-packing changeout on fixed schedule	Monitoring with replacement threshold for rod-packing
Centrifugal Compressors		
Gathering and Boosting Stations	No requirement	Route to control
Natural gas processing plants	Route to control	Route to control
Transmission and Storage Compressor Stations	Route to control	Route to control
Liquids Unloading		
Well Sites	No requirement	Zero emissions or best management practices[d]
Storage Vessels		
PTE $\geq$ 6 tpy VOC	95% control, affected facility is the tank	95% control, affected facility is the tank battery
PTE < 6 tpy VOC	No requirement	No requirement

[a] Operators are required to perform a survey to verify that actual site emissions are reflected in the baseline calculation. This survey reflects BSER but is not costed in the analysis.
[b] The proposed rule includes co-proposals for fugitive emissions monitoring frequency at well sites with calculated emissions between 3 and 8 tpy of methane. The BSER for the primary proposal, which is the central policy scenario in this analysis, is quarterly OGI. The BSER for the co-proposal is semiannual OGI.
[c] Operators of sites are required to install non-emitting systems for controllers except for sites located in Alaska where onsite power is not available. Instead, operators of those sites are prohibited from installing continuous-bleed controllers that exceed an emissions limit, except in cases where failing to do so would create a safety concern.
[d] Under the proposed regulation, liquids unloading events at well sites would be treated as modifications that would trigger the NSPS OOOOb requirements for liquids unloading only. The proposed regulation requires liquids

unloading events to be zero-emitting unless technical infeasibilities exist, in which case the regulation requires that best management practices be adopted.

Table 2-2 EG OOOOc Emissions Sources, Baseline Requirements, and Requirements under the Primary Proposed Option

Source	BSER: In the Baseline	BSER: Under the Proposal
Fugitive Emissions/Equipment Leaks		
Well Sites		
Bin 1: 0 – 3 tpy	Pre-OOOOa: no requirement Post-OOOOa: semiannual OGI	Verify baseline methane emissions[a]
Bin 2: 3 – 8 tpy		Quarterly OGI[b]
Bin 3: 8+ tpy		Quarterly OGI
Gathering and Boosting Stations	Pre-OOOOa: no requirement Post-OOOOa: quarterly OGI	Quarterly OGI
Transmission and Storage Compressor Stations		
Natural gas processing plants	Pre-KKK: no requirement Post-KKK and Pre-OOOO: NSPS Subpart VV Post-OOOO: NSPS Subpart VVa	Bimonthly OGI
Pneumatic Pumps		
Well Sites	Pre-OOOOa: no requirement Post-OOOOa: route to control	Route to control
Gathering and Boosting Stations	No requirement	
Pneumatic Controllers		
Well Sites	Pre-OOOO: no requirement Post-OOOO: emissions limit	Non-emitting or emissions limit[c]
Gathering and Boosting Stations		
Transmission and Storage Compressor Stations	Pre-OOOOa: no requirement Post-OOOOa: emissions limit	
Natural gas processing plants	Pre-OOOO: no requirement Post-OOOO: instrument air system	Instrument air system
Reciprocating Compressors		
Gathering and Boosting Stations	Pre-OOOO: no requirement Post-OOOO: rod-packing changeout on fixed schedule	Monitoring with replacement threshold for rod-packing
Natural gas processing plants		
Transmission and Storage Compressor Stations	Pre-OOOOa: no requirement Post-OOOOa: rod-packing changeout on fixed schedule	
Centrifugal Compressors		
Gathering and Boosting Stations	No requirement	Route to control
Natural gas processing plants	Pre-OOOO: no requirement Post-OOOO: route to control	
Transmission and Storage Compressor Stations	Pre-OOOOa: no requirement Post-OOOOa: route to control	
Storage Vessels		
PTE ≥ 20 tpy CH_4	Pre-OOOO: no requirement Post-OOOO: 95% control, affected facility is the tank[d]	95% control, affected facility is the tank battery[d]
PTE < 20 tpy CH_4 and ≥ 6 tpy VOC		No requirement
PTE < 20 tpy CH_4 and < 6 tpy VOC	No requirement	

[a] Operators are required to perform a survey to verify that actual site emissions are reflected in the baseline calculation. This survey reflects BSER but is not costed in the analysis. Post-OOOOa and pre-OOOOb well sites are subject to the NSPS OOOOa requirements as well as the EG OOOOc requirements, and so well sites in methane emissions Bin 1 would still be required to perform semiannual OGI if the proposed regulation is finalized.

[b] The proposed rule includes co-proposals for fugitive emissions monitoring frequency at well sites with calculated emissions between 3 and 8 tpy of methane. The BSER for the primary proposal, which is the central policy scenario in this analysis, is quarterly OGI. The BSER for the co-proposal is semiannual OGI.
[c] Operators of sites are required to install non-emitting systems for controllers except for sites located in Alaska where onsite power is not available. Instead, operators of those sites are prohibited from installing continuous-bleed controllers that exceed an emissions limit, except in cases where failing to do so would create a safety concern.
[d] As an example, a post-OOOO tank battery with 4 tanks each emitting 5 tons per year VOC would not be required to achieve 95 percent control in the baseline, since the affected facility is the individual tank and emissions fall below the 6 tons per year VOC threshold. Under the proposed rule, the same tank battery would be required to achieve 95 percent control, as the affected facility is the tank battery, which in this example emits 20 tons per year of VOC, exceeding the 6 tons per year VOC threshold.

2.2 Methodology

The compliance cost and emissions reductions analysis summarized in this RIA reflects a nationwide engineering analysis of which there are two main components: activity data and information on control measures. The activity data represents estimates of the counts of affected facilities over time, and the control measure information includes data on costs and control efficiencies for typical facilities.

The first component is activity data for a set of representative or model plants for each regulated facility.[6] For each regulated facility type, unique model plants are defined across each applicable industry segment and regulatory vintage.[7] Moreover, where more detailed data exists, several model plants are constructed to capture important sources of heterogeneity within a regulated facility type and segment (e.g., oil versus natural gas wells). Using a variety of data sources and some basic assumptions on retirement rates, we generate projections of counts of regulated facilities into the future.

The regulated facility projections are combined with information on control options, including capital and annual operations and maintenance costs and control efficiencies. Information on control options is derived from the analysis underpinning the BSER determinations. Impacts are calculated by setting parameters on how and when affected facilities are assumed to respond to a regulatory regime, multiplying activity data by model plant cost and emissions estimates,

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[6] Regulated facilities include well site fugitives, gathering and boosting station fugitives, transmission and storage compressor station fugitives, natural gas processing plant equipment leaks, pneumatic pumps, pneumatic controllers, reciprocating compressors, centrifugal compressors, liquids unloading, and storage vessels.
[7] Industry segments include production, gathering and boosting, processing, transmission, and storage. Regulatory vintages include sources constructed prior to proposal dates for NSPS OOOO, after NSPS OOOO and before NSPS OOOOa, after NSPS OOOOa and before NSPS OOOOb, and after NSPS OOOOb.

differencing from the baseline scenario, and then summing to the desired level of aggregation. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted in production or sold. Where applicable, we present projected compliance costs with and without the projected revenues from product recovery.

For the analysis, we calculate the cost and emissions impacts of the proposed NSPS OOOOb and EG OOOOc from 2023 to 2035. The initial analysis year is 2023 as we assume the proposed rule will be finalized towards the end of next year (2022). The NSPS OOOOb will take effect immediately and impact sources constructed after publication of the proposed rule. We assume the EG OOOOc will take longer to go into effect as states will need to develop implementation plans in response to the rule and have them approved by the Agency. We assume that this process will take three years, and so EG OOOOc impacts will begin in 2026. The final analysis year is 2035, which allows us to provide ten years of impacts after the EG OOOOc is assumed to take effect.

While it would be desirable to analyze impacts beyond 2035, limited information available to model long-term changes in practices and equipment use in the oil and natural gas industry make the choice of a longer time horizon infeasible. In a dynamic industry like oil and natural gas, technological progress is likely to change control methods to a greater extent over a longer time horizon, creating more uncertainty about impacts of the NSPS OOOOb and the EG OOOOc. For example, the current analysis does not include potential fugitive emissions controls employing remote sensing technologies currently under development.

2.2.1 Activity Data Projections

To construct the activity data projections used in this analysis, we rely on historical data from the Greenhouse Gas Inventory (GHGI),[8] information from the private firm Enverus that provides energy sector data and analytical services,[9] and projections from the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO).[10] Our projections follow a two-step

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[8] See Methodology Annexes 3.5 and 3.6 at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2019-ghg. Activity data is presented in Tables 3.5-5 and 3.6-7, respectively.
[9] Enverus: https://www.enverus.com/.
[10] EIA AEO: https://www.eia.gov/outlooks/aeo/.

procedure. First, we construct projected counts of oil and natural gas "sites," such as well sites, compressor stations, and processing plants, that contain or are themselves facilities affected by the regulations. Second, we build upon the site projections to estimate the counts of these "affected facilities." The details of these calculations are described by site/regulated facility type below.

In addition to sites and affected facilities, there is a third category of activity data that we track. When comparing a new regulatory regime, such as the proposed rule, to the baseline scenario, a subset of affected facilities is assumed to take action to comply with regulatory requirements: we refer to these facilities as "incrementally impacted facilities." In Section 2.2.1.3 below, we provide a table of incrementally impacted facility counts for the proposed rule relative to the baseline.

2.2.1.1 Projected Oil and Natural Gas Sites

There are three types of "sites" in our analysis of projected facilities: well sites, compressor stations, and natural gas processing plants. Compressor stations are further subdivided into sites located in different segments of the natural gas sector, that is, the gathering and boosting, transmission, and storage segments. For each site type, we generate annual projections of cumulative and new counts for four different "vintage" bins: the first vintage (V1) represents sites constructed prior to NSPS OOOO, the second vintage (V2) represents sites constructed after NSPS OOOO but prior to NSPS OOOOa, the third vintage (V3) represents sites constructed after NSPS OOOOa but prior to NSPS OOOOb, and the fourth vintage (V4) represents sites constructed after NSPS OOOOb.

There are two countervailing forces that impact the overall trajectory of our estimated sites beyond the base year: the rate at which new sites are constructed and the rate at which sites retire (or cease operation). In our analysis, counts of newly constructed sites are based on either historical trends from the GHGI (processing plants and compressor stations) or projections from AEO (well sites). Estimates of retirement rates are based on assumptions underlying analysis submitted in response to the 2018 NSPS OOOOa Policy Reconsideration proposal;[11] along with new site counts, those rates are summarized in Table 2-3.

Table 2-3 Assumed Retirement Rates and Annual New Site Counts by Site Type

Type of Site	New Site Counts in Each Year	Annual Retirement Rate as a Percentage of Existing Stock
Well Sites	14,000 – 31,000	5%
Compressor Stations		
Gathering and Boosting	616	4%
Transmission	106	1%
Storage	3	1%
Natural Gas Processing Plants	36	1%

Our projections of the cumulative counts of sites for each vintage are illustrated in

Figure 2-1. The projected total counts of well sites decline significantly over the analysis horizon, as smaller V1 sites are displaced by larger V3 and V4 sites. The total counts of storage compressor stations decline slightly over time, due to very few assumed annual additions. For all other site types, the total number of sites increase significantly over the analysis horizon. Below, we describe how those trajectories are generated for each site type.

[11] See page 4 of Appendix D of Docket ID No. EPA-HQ-OAR-2017-0757-0002.

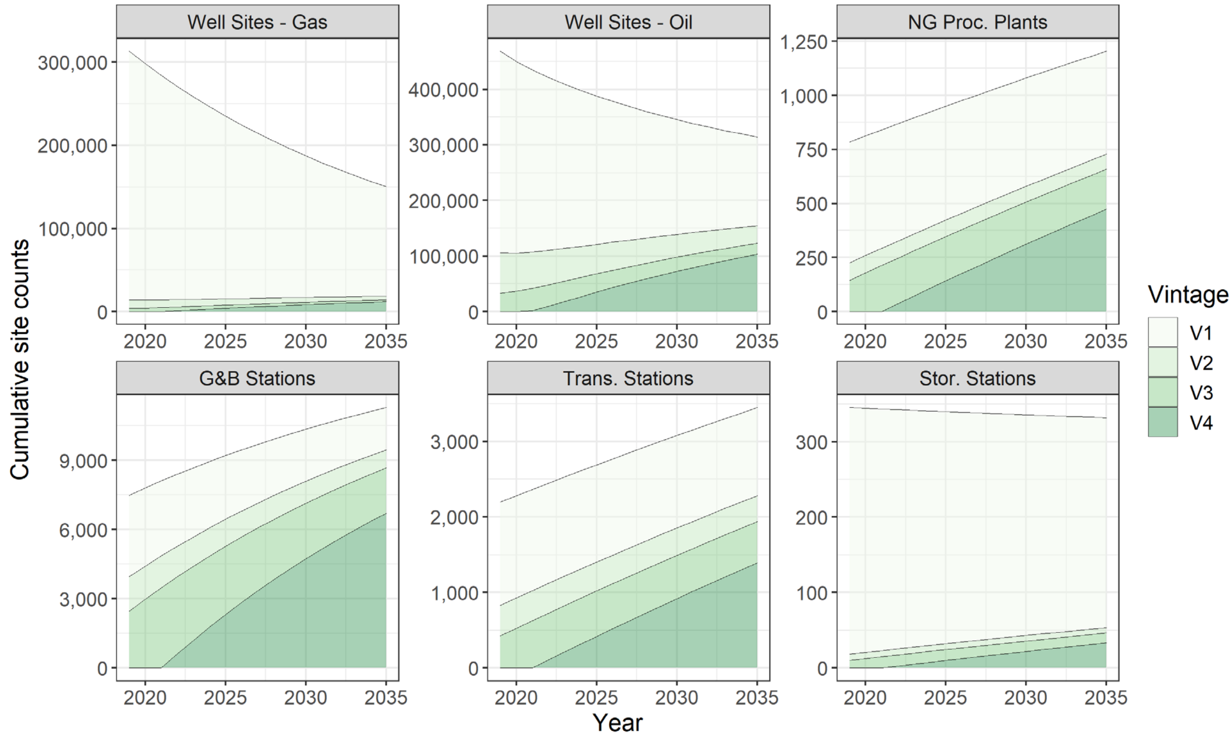

Figure 2-1 Projections of Cumulative Site Counts by Site Type and Vintage

(a) Well Sites

The dataset used to characterize the base year (2019) population of oil and natural gas well sites is developed from data provided by Enverus, a private firm focused on the energy industry that provides data and analytical services. The dataset includes two types of entities: wells and leases. Whether a well is represented as its own entity or as part of a lease depends on the state in which the well is located, as reporting requirements differ across state agencies. The columns in the dataset include entity identifiers, well site identifiers (for wells), locations, completion and initial production dates, well counts (for leases), and natural gas and liquids production levels. We restricted the dataset to onshore wells with positive production values in 2019. The base year is chosen as 2019 as we assume that it is the most recent year with comprehensive data coverage due to reporting lags.

Using the base year dataset, we generate counts of wells grouped by state, vintage, and well type (oil or natural gas). For well entities, vintages are assigned by taking the most recent of the completion date and first production date for all wells at the site; hence, all wells at a site have the same vintage. For lease entities, the process is analogous to all wells on a lease being assigned the same vintage. Likewise, all wells on a site or lease are assigned the same well type. Well type is constructed by calculating the site- or lease-wide gas-to-oil ratio (GOR); if GOR > 100,000 mcf per bbl, then the well is assumed to be a natural gas well, otherwise, it is assigned as an oil well.

To build the future projections, the base year well site dataset is merged with AEO2021 projections of new wells drilled from 2020 to 2035. As AEO2021 only publicly reports new wells at the national level and does not distinguish by geographic location or well type, the AEO2021-based projection of new wells is disaggregated across states and well types in the same proportions as the post-OOOOa wells in the base year dataset. Of the projected new wells, all the 2020 and 75 percent of the 2021 wells are assigned to vintage V3. The remainder of the 2021 wells, and all other projected future new wells are assigned to vintage V4. We recursively calculate cumulative wells in each year (starting with 2020) for each state-vintage-well type bin by adding new wells in the current year to the number of cumulative wells from the previous year less retirements.

After wells have been assigned to bins, we calculate the number of well sites in each state-vintage-well type bin as the proposed requirements for fugitive emissions apply to well sites, which have one or more co-located wells at each site. This is done by calculating the average number of wells at a well site for each bin using the base year dataset and then dividing the total number of wells in each bin (in each year) by the corresponding average. Average wells per site are calculated by determining the number of wells at each well site in the base year dataset within a bin and then taking the mean.[12] In states in which wells are only assigned to leases and no site averages can be calculated, national averages are assigned.

As a final step, we allocate wells sites into two "site equipment" categories and three "site electrification" categories, which are needed to estimate the impacts of requirements related to fugitive emissions monitoring and pneumatic controllers. The site equipment categories distinguish well sites that are wellhead only and those that possess a range of production and processing equipment. Based on information provided by the American Petroleum Institute, we

[12] We only use sites with fewer than 100 wells to calculate the average wells per site to minimize the influence of imperfections in Enverus' site grouping algorithm.

assume that 27 percent of well sites are wellhead only.[13] In the absence of more detailed information, that percentage is uniformly applied to all state-vintage-well type bins. The site electrification categories distinguish sites with access to reliable electricity and sites without. Based on requirements for pneumatic controllers at well sites in Colorado's Air Quality Control Commission Regulation Number 7,[14] we assume that 40 percent of well sites have access to reliable electricity. In addition, we assume that the remaining 60 percent of well sites can install solar photovoltaic (PV) and battery systems to power zero-emitting controllers.[15]

(b) Compressor Stations

We project compressor stations for three segments (gathering and boosting, transmission, and storage) using data from GHGI; the approach for all three segments is analogous.[16] The first step is to estimate the number of stations in the base year, 2019. We assume that the number of stations in 2011 are all V1 stations (pre-OOOO). To get the counts of V1 stations in subsequent years, including the base year, we apply the relevant annual retirement rates to the 2011 station counts. The number of V2 stations (post-OOOO, pre-OOOOa) in 2019 is estimated by subtracting the estimated number of V1 stations in 2015 from the total station counts from 2015, and then applying the retirement rates. The number of V3 stations (post-OOOOa) in 2019 is estimated by subtracting the estimated number of V1 and V2 stations in 2019 from the total number of stations.

To project the number of new stations constructed in the years after the base year, we calculate a historical average number of new stations per year over a recent period and apply it uniformly across all years. Specifically, we divide the calculated number of V3 stations in 2019 and divide it by four, as the first V3 stations are assumed to be constructed in 2016. This yields an estimate of the average number of V3 stations added per year through the base year, and we assume new stations are added at that same rate beyond the base year. New stations assumed to be

[13] Memoranda for Meetings with the American Petroleum Institute (API), September 23, 2021, located at Docket ID No. EPA–HQ– OAR–2021–0317.

[14] See the last entry in Table 1 on page 150 in 5 CCR 1001-9, found at https://cdphe.colorado.gov/aqcc-regulations.

[15] This assumption is based on analysis put forth by the New Mexico Environment Department in support of its 20.2.50 NMAC Oil and Gas Sector-Ozone Precursor Pollutants Rulemaking. See the pneumatics workbook link *Pneumatics Reductions and Costs VOC 5-27-21_erg (06-08-2021)* at https://www-archive.env.nm.gov/air-quality/ozone-precursor-rule-hearing/.

[16] Station counts are extracted from the following rows: *Yard Piping* (gathering and boosting) and *Station + Compressor Fugitive Emissions* (transmission and storage).

constructed in 2020 and 2021 are assigned to V3, while all estimated new stations beyond 2021 are assigned to V4.

Cumulative station counts in all years from the base year through 2035 are constructed in the same manner as they are for well sites. Each year, the cumulative number of sites is equal to the sum of the unretired number of sites from the previous year and the new sites in the current year. Cumulative station counts are tracked for all vintage bins. Finally, we assume that 40 percent of gathering and boosting stations and all transmission and storage compressor stations have access to reliable electricity. The remaining gathering boosting stations are assumed to be able to install solar PV and battery systems to power zero-emitting controllers.

(c)　Natural Gas Processing Plants

To construct base year activity data counts for natural gas processing plants, we leverage data from both the GHGI and Enverus. The estimates of the counts of V1 and V2 plants are generated using the same process as for compressor stations: the 2011 count of plants are assigned to V1, and the V2 count of plants in 2015 is estimated to be the 2015 count from the GHGI minus the estimated count of V1 plants in 2015 after the annual retirement rates are applied. Our 2019 total plant count is based on midstream data from Enverus rather than GHGI since plant counts have been fixed in the GHGI in recent years due to lack of data.[17] Estimates for the counts of V1, V2, and V3 plants in the base year are then calculated using the 2019 total plant estimate as described above for compressor stations, as is the estimated number of new plants in each year beyond the base year. Cumulative plant counts for the base year through 2035 are also generated analogously to compressor stations. Finally, unlike well sites and compressor stations, we assume that all processing plants have access to reliable electricity.

2.2.1.2 Affected Facilities

In most cases, estimates of projected affected facility counts are generated by assuming fixed proportional relationships with the site counts. This means that as site counts are projected to expand (construction of new sources) or contract (retirement of existing sources), the counts of

[17] The Enverus processing plant data is restricted to the following entries in the Type column: Cryogenic, Cryogenic/Fractionator, Cryogenic/Refrigerator, Fractionator, Gas Plant Sweet, Processing Plant, and Processing Plant/Fractionator. Additionally, non-fractionator plants with unknown capacities and capacities less than 10 million cubic feet per day are removed from the dataset.

affected facilities expand and contract as well such that the ratio of facilities to sites remains constant. Details for each affected facility type are provided below.

(a) Fugitives and Leaks

The proposed rule features different monitoring frequency requirements for well sites depending on baseline emissions calculations. In the analysis of the primary proposed option, wellhead-only sites and sites with 0–3 tons per year of methane emissions are assumed to be exempted from monitoring, sites with 3 or more tons per year of methane emissions are assumed to perform quarterly monitoring. In the analysis of the co-proposed option, the requirements are the same except for sites with 3–8 tons per year of methane emissions, which are assumed to perform semiannual monitoring. To calculate impacts for the fugitive monitoring requirements at well sites, we allocate the total number of non-wellhead-only sites to the fugitive emissions bins.

The proportions of sites in each monitoring bin are presented in Table 2-4. Proportions differ across oil and natural gas sites, pre-OOOO and post-OOOO sites, and sites with and without non-emitting controllers. Details on the data and methodology used to develop those proportions are provided in Appendix A. We apply the same proportions to cumulative and new well site counts in all analysis years.

Table 2-4 Distribution of Well Sites and Well Site Emissions in Regulatory Bins

Site Bin	Proportion	Methane emissions (short tons per year per site)
Natural Gas		
Pre-OOOO		
0-3 tpy	0.15	2.2
3-8 tpy	0.44	5.0
8+ tpy	0.41	18
Post-OOOO		
0-3 tpy	0.32	2.2
3-8 tpy	0.46	4.8
8+ tpy	0.22	13
Oil		
Pre-OOOO		
0-3 tpy	0.48	1.9
3-8 tpy	0.43	4.8
8+ tpy	0.09	10
Post-OOOO		
0-3 tpy	0.53	1.9
3-8 tpy	0.40	4.8
8+ tpy	0.07	10

Note: The proportion of sites in each bin are conditional on the well sites not being assumed to be categorized as wellhead only.

Affected facility counts for compressor station fugitives are equal to the compressor station counts detailed in the previous section. As such, compressor station fugitives affected facility counts are binned according to segment, vintage, and year.

There are two affected facility types associated with natural gas processing plant leaks: the collection of VOC service components and the collection of non-VOC service components. In each case, the number of affected facilities is equal to the number of processing plants, and so the total number of affected facilities is twice the number of processing plants. For the purposes of calculating impacts associated with LDAR at processing plants, we assume that 80 percent of plants are "large" and 20 percent are "small."[18]

(b) Pneumatic Pumps

The GHGI provides information on the number of pneumatic pumps in the production and gathering and boosting segments. To project the number of pumps in production, we first divide the number of diaphragm pumps in 2019 by the number of non-wellhead-only oil and natural gas wells in 2019. Likewise, we divide the GHGI estimate of pumps in gathering and boosting by the number of stations. As the GHGI only provides counts of chemical injection pumps, we assume that 50.2 percent are diaphragm pumps in both segments.[19] We then apply the per-site proportions uniformly across all vintages and years to estimate the number of total pumps in each year for each bin. As a final step, we assume that 75 percent of pumps are at sites with existing combustion devices and 25 percent are at sites without them.[20] This distinction is necessary because the proposed rule exempts pumps at sites without existing controls from the regulation for both the NSPS OOOOb and the EG OOOOc.

(c) Pneumatic Controllers

The affected facility for pneumatic controllers is the site, such that any well site, compressor station, or processing plant with pneumatic controllers is treated as a single affected facility, no matter how many controllers are on the site. Using information from the GHGI, we project the

[18] See page 6 of Chapter 10 of the 2021 TSD.
[19] See page 14 of Volume 13: Chemical Injection Pumps of GRI/EPA (1996).
[20] See page 151 of the TSD for the finalized 2016 NSPS OOOOa, Docket ID No. EPA-HQ-OAR-2010-0505-7631 (U.S. EPA, 2016).

composition of pneumatic controllers at sites for all segments, assuming uniformity in the total number of controllers within a site type (e.g., oil or natural gas well, transmission compressor station).

For all site types except processing plants, pneumatic controllers are divided into three types in the GHGI: high-bleed, intermittent bleed, and low-bleed. To calculate the number of pneumatic controllers per site, we sum the 2019 values from the GHGI across controller types and divide by the number of sites in 2019. In the case of production, we perform separate calculations for oil and natural gas wells to calculate the number of pneumatic controllers per well (excluding wells on wellhead-only sites). We then multiply by the state/vintage/well type-specific average number of wells per site to estimate the number of controllers per site.

After calculating the number of pneumatic controllers per site, we apply those ratios to the projected site counts and divide the totals within each site into the three pneumatic controller types. To account for requirements promulgated in the NSPS OOOO and OOOOa, we assign all high-bleed controllers to sites in vintage bin V1 (for production and gathering and boosting) or V1 and V2 (for transmission and storage). If the ratio of high-bleed controllers to sites in 2019 is less than one, we assume that proportion of sites have one high-bleed controller. If the ratio exceeds one, we assume that all sites have that number of high-bleed controllers. We then calculate the number of intermittent bleed pneumatic controllers at each site such that the ratio of intermittent to non-high-bleed pneumatic controllers matches the 2019 values from the GHGI for each site type. All remaining unassigned controllers are assumed to be low-bleed.

After determining the distribution of controller types across and within sites, we have counts, by site, of low-, intermittent, and high-bleed controllers. Well sites and gathering and boosting compressor stations constructed prior to NSPS OOOO, and transmission and storage compressor stations constructed prior to NSPS OOOOa, are divided into sites with high-bleed controllers and those without, while the more recently constructed sites are assumed to only have intermittent and low-bleed controllers. Sites are further divided into those assumed to have access to reliable electricity and those assumed to not have access, as discussed in the previous section.

Pneumatic controllers at processing plants are treated differently than they are for the other segments. We assume that all plants have access to reliable electricity and that half of the processing plants have or will, regardless of NSPS OOOOb regulatory requirements, install compressed air systems in the baseline.[21] To conform to the model plant BSER analysis, controllers are not broken out by type; instead, the cost and emissions estimates of the proposed option are applied based on the number of controllers assumed to be at the processing plant. Consistent with the NSPS OOOO RIA, we assume that there are fifteen pneumatic controllers at all sites (U.S. EPA, 2012a).

(d) Reciprocating Compressors

The GHGI contains estimates of the number of reciprocating compressors in the gathering and boosting, processing, transmission, and storage segments. In all cases, we calculate the number of reciprocating compressors per site using the 2019 values from the GHGI and apply those ratios to the cumulative and new station counts for all vintages and years. In the case of gathering and boosting stations, the GHGI only includes a total count of compressors; we assume that 89 percent of those are reciprocating.[22]

(e) Centrifugal Compressors

The GHGI contains estimates of the number of wet-seal centrifugal compressors in the gathering and boosting, processing, and transmission segments. In all cases, we calculate the number of wet-seal centrifugal compressors per site using the 2019 values from the GHGI and apply those ratios to the cumulative and new station counts for all vintages and years. In the case of gathering and boosting stations, the GHGI only includes a total count of compressors; we assume that 3 percent of those are centrifugal,[23] and that the proportion of wet-seal to dry-seal centrifugal compressors is the same as it is in the transmission segment.

(f) Liquids Unloading

For the purposes of the RIA, liquids unloading affected facilities are defined at the event level and apply only to natural gas well sites. To estimate impacts more accurately, we divide natural gas wells into two categories: those with plunger lifts and those without plunger lifts. The GHGI contains activity data for the number of wells in each category that perform liquids unloading

[21] An identical assumption was made in the analysis supporting the proposed 2011 NSPS OOOO. See page 5-9 of the TSD for that proposal, Docket ID No. EPA-HQ-OAR-2010-0505-0045 (U.S. EPA, 2011a).
[22] This assumption is based on data summarized on page 28 of Zimmerle et al. (2019).
[23] Ibid.

events, so we divide that number by the total number of natural gas wells in the inventory in 2019 to generate fractions of wells performing liquids unloading for each category. Those fractions are applied to our projections of cumulative and new wells for all years and vintages. In the case of wells with plunger lifts, we assume that 76 percent of wells perform manual unloading.[24] Finally, we convert from wells to events by multiplying by events per well values from the BSER analysis.[25]

(g) Storage Vessels

Storage vessel affected facility projections are constructed by combining data from the storage vessels analysis presented in the 2021 TSD, GHGI data on storage vessels, and the well drilling projections from AEO2021. First, we calculate the ratio of tank batteries per million barrels (MMBbl) throughput for oil and natural gas wells separately by dividing a historical year estimate (1992 for natural gas, 2006 for oil) of tank batteries from the 2021 TSD by the throughput estimate for the corresponding year from the GHGI.[26] Then we apply those ratios to throughput values from the GHGI for 2011, 2015, and 2019 to estimate counts of tank batteries in vintages V1-V3, using an analogous process to the one described for compressor stations in the previous section. This produces base year (2019) estimates of cumulative tank battery counts for oil and natural gas by vintage.

To project new and cumulative tank battery counts beyond the base year, we apply ratios of tank batteries per well to the AEO2021 well drilling projections, after the drilling counts have been apportioned between oil and natural gas wells based on the estimates of V3 wells from the Enverus data. The ratios, separately calculated for oil and natural gas wells, are calculated by multiplying the historical year ratio of tank batteries per MMBbl throughput by the GHGI estimates of throughput in 2019 to get an estimate of tank batteries in the base year, and then dividing by the estimates of wells in 2019 from the GHGI. New tank batteries assumed to be constructed in 2020 and 2021 are assigned to V3, while all estimated new stations beyond 2021

[24] Memorandum. *Analysis of Greenhouse Gas Reporting Program Liquids Unloading Data*. Prepared by SC&A Incorporated for Amy Hambrick, SPPD/OAQPS/EPA. October 14, 2021. As summarized in the memo, which is available in the docket, analysis of well-level data from the GHGRP for reporting years 2015–2019 suggested that 76% of plunger lifts were manually operated.

[25] See page 12 of Chapter 11 of the 2021 TSD. We assume that wells without plunger lifts have 5.6 events per year, and wells with manually operated plunger lifts have 7.7 events per year.

[26] See pages 9–10 of Chapter 6 in the 2021 TSD.

are assigned to V4. Cumulative tank battery counts in all years beyond the base year are estimated using base year counts and new counts in the same manner as they are for sites, with the retirement rate assumed to be the same as the well site rate.

2.2.1.3 Incrementally Impacted Facilities

Estimates of incrementally impacted facility counts by year and regulated facility for the proposed rule are presented in Table 2-5. The counts for well sites and compressor stations represent fugitives requirements at those sites and the counts for natural gas processing plants represent VOC and non-VOC service. The counts for pneumatic controllers represent the number of sites, rather than the number of controllers, since the model plant is defined as the site.

Table 2-5 Projection of Incrementally Impacted Affected Facilities under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023 to 2035

Year	Well Sites	Gathering and Boosting Stations	Transmission and Storage Compressor Stations	Natural Gas Processing Plants	Pneumatic Pumps	Pneumatic Controllers	Reciprocating Compressors	Centrifugal Compressors	Liquids Unloading	Storage Vessels
2023	13,000	0	0	130	910	14,000	3,800	30	4,000	280
2024	19,000	0	0	190	1,300	21,000	5,600	44	5,800	410
2025	24,000	0	0	250	1,700	27,000	7,300	57	7,700	560
2026	280,000	3,700	1,900	1,700	33,000	420,000	36,000	1,100	190,000	920
2027	270,000	3,500	1,800	1,800	32,000	410,000	37,000	1,100	180,000	1,000
2028	260,000	3,400	1,800	1,800	31,000	400,000	38,000	1,100	180,000	1,200
2029	260,000	3,200	1,800	1,900	30,000	390,000	38,000	1,100	170,000	1,300
2030	250,000	3,100	1,800	1,900	29,000	370,000	39,000	1,100	160,000	1,400
2031	240,000	3,000	1,800	2,000	28,000	360,000	40,000	1,000	160,000	1,500
2032	240,000	2,900	1,800	2,000	27,000	350,000	41,000	1,000	150,000	1,600
2033	230,000	2,700	1,700	2,100	27,000	340,000	42,000	1,000	150,000	1,700
2034	230,000	2,600	1,700	2,100	26,000	340,000	42,000	1,000	140,000	1,700
2035	230,000	2,500	1,700	2,100	25,000	330,000	43,000	1,000	140,000	1,800

2.2.2 Model Plant Compliance Cost and Emissions Reductions

The cost and emissions characteristics of the model plants used to estimate the impacts of the proposed rule are derived from the technical analyses underpinning the BSER determination. In most cases, we define the model plant for our affected facilities to be identical to the model plants found in the 2021 TSD, and so the cost and emissions estimates can be directly applied. In a few cases, however, our model plants leverage the underlying data from the 2021 TSD to better fit the activity data.

We use cost and emissions information without modification from the 2021 TSD for the following affected facilities: compressor station fugitives, natural gas processing plant leaks, pneumatic pumps, reciprocating compressors, and wet-seal centrifugal compressors. Compressor station fugitives are represented by a single model plant for each of the gathering and boosting, transmission, and storage segments.[27] Processing plant leaks are divided into four different model plants: all combinations of large and small plants, and VOC and non-VOC service.[28] Pneumatic pumps are represented by a single model plant that is assumed to be identical across the production and gathering and boosting segments.[29] Reciprocating compressors are represented by a single model plant for each of the gathering and boosting, processing, transmission, and storage segments.[30] Wet-seal centrifugal compressors are represented by a single model plant for each of the gathering and boosting, processing, and transmission segments.[31]

Well site fugitives are represented by separate model plants for all combinations of the following elements: oil or natural gas; wellhead-only and non-wellhead only, with the latter split into the

[27] See Chapter 12 of the 2021 TSD for details on costs and emissions reductions associated with quarterly OGI monitoring, which represents the proposed BSER for compressor station fugitives in both the NSPS OOOOb and EG OOOOc.

[28] See Chapter 10 of the 2021 TSD for details on costs and emissions reductions associated with NSPS VV Method 21 (the BSER established in NSPS KKK), NSPS VVa Method 21 (the BSER established in NSPS OOOO), and bimonthly OGI (the BSER proposed in NSPS OOOOb and EG OOOOc).

[29] See Chapter 9 of the 2021 TSD for details on costs and emissions reductions associated with routing pneumatic pump emissions to an existing control device, which represents the proposed BSER for compressor station fugitives in both the NSPS OOOOb and EG OOOOc.

[30] See Chapter 7 of the 2021 TSD for details on costs and emissions reductions associated with rod-packing replacement on a fixed schedule (the BSER established in NSPS OOOO and NSPS OOOOa) and rod-packing replacement based on emissions monitoring (the BSER proposed in NSPS OOOOb and EG OOOOc).

[31] See Chapter 7 of the 2021 TSD for details on costs and emissions reductions associated with routing wet-seal centrifugal compressor emissions to a new control device, which is the compliance option we assume for this analysis. The BSER also allows for routing to an existing control device or to a process.

three fugitive emissions bins described in the previous section; and pre-OOOO and post-OOOO. Model plant emissions associated with fugitives are calculated through the Monte Carlo simulation procedure described in Appendix A. Model plant costs are independent of emissions levels and are taken directly from the 2021 TSD.[32]

Pneumatic controllers are represented by many different model plant configurations. In the production segment, there are different model plants for all combinations of oil and natural gas well sites and high-bleed controller status (i.e., is there a high bleed controller on site?). Moreover, each combination of well site and high-bleed controller status has a separate model plant for each state and vintage, since the number of controllers is tied to the number of wells at a site, and the average wells per site varies by state and vintage. There are two model plants each for gathering and boosting, transmission, and storage compressor stations, one for each high-bleed controller status. There is a single model plant for pneumatic controllers at natural gas processing plants.

For all segments except processing, model plants are characterized by the number of pneumatic controllers at the site and how they are distributed across low-, intermittent, and high-bleed controller types.[33] Emissions for the model plant are calculated by multiplying the counts of controller types by respective emissions factors and summing to the site level.[34] Costs for the model plant are calculated by adding a component that is invariant to the number of controllers at the site to a component that is scaled by the total number of controllers at the site.[35] In the

[32] See Chapter 12 of the 2021 TSD for details on costs and emissions reductions associated with semiannual, quarterly, and monthly OGI monitoring at well sites. Semiannual OGI was established as BSER at well sites with equipment in NSPS OOOOa. Quarterly OGI is proposed as BSER at well sites with baseline methane emissions greater than 3 tpy in NSPS OOOOb and EG OOOOc.

[33] See Chapter 8 of the 2021 TSD for details on costs and emissions reductions associated with replacing high bleed with low bleed pneumatic controllers (the BSER established in NSPS OOOO for well sites and gathering and boosting stations and NSPS OOOOa for transmission and storage compressor stations) and installing zero-bleed controllers (the BSER established in NSPS OOOO for processing plants and proposed in NSPS OOOOb and EG OOOOc for all other segments unless infeasible).

[34] While the BSER analysis uses emissions factors for controllers at production sites based on an API study, in the RIA we use the GHGRP subpart W emissions factors referenced on page 8 of Chapter 8 of the 2021 TSD.

[35] For example, the BSER analysis estimates electronic system costs of \$4,000 for a control panel and \$4,000 per controller plus 20% of total equipment costs for installation and engineering. For the RIA analysis, this translates into, for a model plant with 6 controllers (a configuration that does not exist in the BSER analysis), total cost estimates of $(1 + 0.20) \times (\$4,000 + \$4,000 \times 6) = \$33,600$.

processing segment, costs and emissions are taken directly from the 2021 TSD as we assume the same model plant configuration for our analysis.

We define two model plants for liquids unloading: events at wells without plunger lifts and manual unloading events at wells with plunger lifts. In both cases, the costs per event are taken directly out of the 2021 TSD. However, whereas the BSER analysis evaluates a range of emissions reductions levels associated with the proposed option, this analysis assumes emissions reductions of 29 percent and 36 percent for events at wells without plunger lifts and manual unloading events at wells with plunger lifts, respectively.[36]

Finally, we define four model plants for storage vessels. One model plant is defined for each combination of the following: tank batteries at oil and natural gas sites, and pre-OOOO and post-OOOO. The analysis in the 2021 TSD is comprised of 80 model plants: four different tank size configurations, each of which has ten possible emissions profiles, for both oil and natural gas sites. Tanks are distributed to tank size configurations based on estimated distributions of tank size; tanks are distributed to pre-OOOO and post-OOOO based on estimated proportions of new tank batteries relative to existing tank batteries. Pre-OOOO and post-OOOO tank batteries are distributed to tank size configurations in the same proportion. Our analysis assumes that the distribution of 2021 TSD model plants within the oil and natural gas distinction is fixed, and so we create two aggregate model plants that weight the costs and emissions associated with the 40 underlying model plants for both pre-OOOO and post-OOOO tanks.[37]

2.2.3 State Programs

The oil and natural gas industry is subject to numerous state and local requirements. These requirements differ greatly in scope and stringency across states. Given the difficulty in

[36] See Chapter 11 of the 2021 TSD for details on costs associated with best management practices during liquids unloading events, which is the compliance option we assume for this analysis. Additionally, see the memo titled "Analysis of Greenhouse Gas Reporting Program Liquids Unloading Data," available in the docket, for details on the emissions reductions assumptions used in the RIA.

[37] See Chapter 6 of the 2021 TSD for details on costs and emissions reductions associated with routing storage vessel emissions to combustion devices or vapor recovery units, which are acceptable compliance options under the proposed BSER for the NSPS OOOOb and EG OOOOc. The cost estimates used for the RIA model plants reflect the same underlying model plants used in the BSER analysis, and the same assumed distributions of compliance options (50 percent routing to combustion devices and 50 percent routing to vapor recovery units; see page 27 in the TSD chapter).

attempting to incorporate the myriad of state regulations in the baseline, we have chosen to incorporate state actions into the baseline for California and Colorado. Both states have comprehensive regulatory programs for the oil and natural gas industry and contribute significantly to national production levels.

Specifically, we assume that California and Colorado have requirements at least as stringent as those in the proposed rule for well site and compressor station fugitives; natural gas processing plant leaks; pneumatic controllers; pneumatic pumps in the production, gathering and boosting, and processing segments; pre-OOOO reciprocating and wet-seal centrifugal compressors in the gathering and boosting and processing segments; and storage vessels. In addition, we assume California has requirements at least as stringent as those in the proposed rule for pneumatic pumps in the transmission and storage segments; pre-OOOO reciprocating and wet-seal centrifugal compressors in the transmission and storage segments; and post-OOOO reciprocating and wet-seal centrifugal compressors in all segments. Finally, we assume that Colorado has requirements at least as stringent as those in the proposed rule for liquids unloading.

To incorporate the California and Colorado rules in the baseline, our activity data projections for sites and affected facilities need to estimate the counts for those states. For the production segment, the processes described in Section 2.2.1.1 already account for state level activity counts. For the other segments, midstream data from Enverus was used to calculate the proportions of natural gas processing plants and compressor stations in California and Colorado. We assume that those proportions hold fixed in all analysis years, and that affected facilities are also distributed according to those proportions.

2.3 Emissions Reductions

Table 2-6 summarizes the emissions reductions associated with the proposed standards. The emissions reductions are estimated by multiplying the source-level emissions reductions associated with each applicable control and facility type by the number of affected sources of that facility type. We present methane emissions in both short tons and CO_2 Eq. using a global warming potential of 25.

Table 2-6 Projected Emissions Reductions under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035

	Emissions Changes			
Year	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO_2 Eq. using GWP=25)**
2023	130,000	39,000	1,500	3,100,000
2024	200,000	57,000	2,200	4,500,000
2025	260,000	75,000	2,800	5,900,000
2026	4,500,000	1,400,000	54,000	100,000,000
2027	4,400,000	1,300,000	52,000	100,000,000
2028	4,300,000	1,300,000	51,000	97,000,000
2029	4,200,000	1,200,000	49,000	94,000,000
2030	4,000,000	1,200,000	48,000	92,000,000
2031	3,900,000	1,200,000	46,000	89,000,000
2032	3,800,000	1,100,000	45,000	87,000,000
2033	3,700,000	1,100,000	44,000	85,000,000
2034	3,700,000	1,100,000	43,000	83,000,000
2035	3,600,000	1,000,000	42,000	81,000,000
Total	**41,000,000**	**12,000,000**	**480,000**	**920,000,000**

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

2.4 Product Recovery

The projected compliance costs presented below include the revenue from natural gas recovery projected under the proposed standards. Requirements for fugitive emissions monitoring, equipment leaks at processing plants, reciprocating compressors, pneumatic controllers, liquids unloading events, and storage vessels are assumed to increase the capture of methane and VOC emissions that would otherwise be vented to the atmosphere, and we assume that a large proportion of the averted methane emissions can be directed into natural gas production streams and sold; see Chapters 6–8 and 10–12 of the 2021 TSD for details on the proportion of recovered emissions associated with the compliance options.

Table 2-7 summarizes the increase in natural gas recovery and the associated revenue. The AEO2021 projects Henry Hub natural gas prices rising from $2.99/MMBtu in 2023 to $3.53/MMBtu in 2035 in 2020 dollars.[38] To be consistent with other financial estimates in the RIA, we adjust the projected prices in AEO2021 from 2020 dollars to 2019 dollars using the

[38] Available at: https://www.eia.gov/outlooks/aeo/excel/aeotab_13.xlsx. Accessed October 7, 2021.

GDP-Implicit Price Deflator. We also adjust prices for the wellhead using an EIA study that indicated that the Henry Hub price is, on average, about 11 percent higher than the wellhead price (Budzik, 2002). Finally, we use a conversion factor of 1.037 MMBtu equals 1 Mcf.[39] Incorporating these adjustments, wellhead natural gas prices are assumed to rise from 3.03/Mcf in 2023 to $3.58/Mcf in 2035.

Table 2-7 Projected Increase in Natural Gas Recovery under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035

Year	Increase in Gas Recovery (Bcf)	Increased Revenue (millions 2019$)
2023	7.3	$22
2024	11	$30
2025	14	$41
2026	240	$730
2027	240	$730
2028	230	$740
2029	220	$740
2030	220	$730
2031	210	$720
2032	200	$710
2033	200	$700
2034	190	$690
2035	190	$680

Note: Values rounded to two significant figures.

Operators in the transmission and storage segment of the industry do not typically own the natural gas they transport; rather, they receive payment for the transportation service they provide. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in a national-level analysis. An economic argument can be made that, in the long run, no single entity bears the entire burden of compliance costs or fully appropriates the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is likely to be spread across different market participants. Therefore, the simplest and most transparent option for allocating these

[39] For MMbtu-Mcf conversion factor, see https://www.eia.gov/outlooks/aeo/data/browser/#/?id=20-AEO2021&cases=ref2021&sourcekey=0. Accessed October 7, 2021.

revenues would be to keep the compliance costs and revenues within a given source category and not make assumptions regarding the allocation of costs and revenues across agents.

2.5 Compliance Costs

Table 2-8 summarizes the compliance costs and revenue from product recovery for the evaluated emissions sources and points. Total costs consist of capital costs, annual operating and maintenance costs, and revenue from product recovery. Capital costs include the capital costs from the requirements on newly affected pumps, controllers, compressors, and storage vessels, as well as the planning costs associated with monitoring requirements for fugitive emissions at well sites and compressor stations and equipment leaks at processing plants; these costs are reincurred as operators are assumed to have to renew survey monitoring plans or purchase new capital equipment at the end of its useful life. The annual operating and maintenance costs are due to requirements on fugitive emissions and equipment leaks, controllers at gas processing plants, compressors, liquids unloading events, and storage vessels. The negative annual operating and maintenance costs in the first three analysis years are due to improved flexibility of the equipment leak survey requirements at natural gas processing plants and reduced regulatory burden in the fugitive emissions monitoring program for low emitting well sites relative to the baseline.

Table 2-8 Projected Compliance Costs under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions 2019$)

Year	Compliance Costs				
	Capital Costs	Operating and Maintenance Costs	Annualized Costs	Increased Revenue from Product Recovery	Annualized Cost (with Increased Revenue from Product Recovery)
2023	$150	($3.7)	$27	$22	$4.8
2024	$170	($5.0)	$40	$30	$9.4
2025	$180	($6.5)	$52	$41	$11
2026	$780	$1,200	$2,200	$730	$1,500
2027	$760	$1,100	$2,100	$730	$1,400
2028	$740	$1,100	$2,000	$740	$1,300
2029	$730	$1,000	$2,000	$740	$1,200
2030	$710	$990	$1,900	$730	$1,100
2031	$700	$940	$1,800	$720	$1,100
2032	$680	$900	$1,700	$710	$1,000
2033	$670	$860	$1,700	$700	$980
2034	$660	$820	$1,600	$690	$930
2035	$650	$780	$1,600	$680	$890

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

The expected lifetimes that capital and planning costs are incurred over differs across affected facilities. The cost of designing, or redesigning, fugitive emissions monitoring programs at well sites and compressor stations are assumed to occur every eight years, while the planning cost associated with equipment leak surveys at processing plants are assumed to occur every five years. Equipment associated with routing pneumatic pump and wet-seal centrifugal compressor emissions is assumed to have a lifetime of 10 years. Pneumatic controllers and equipment associated with routing storage vessel emissions are assumed to have a lifetime of 15 years. Rod-packing replacement at reciprocating compressors is assumed to happen about every 3.3 years in the processing segment, 3.8 years in the gathering and boosting and transmission segments, and 4.4 years in the storage segment.[40] The capital costs in each year outlined in Table 2-8 includes the estimated costs for newly affected sources in that year, plus the costs for sources affected previously that have reached the end of their assumed economic lifetime.

[40] For the purposes of assigning unannualized capital costs of subsequent replacements to years, we round the lifetimes for rod-packing to the nearest whole number.

The calculation of total annualized costs proceeds as follows. Capital and planning costs are annualized over their requisite expected lifetimes at an interest rate of 7 percent. These annualized capital costs are then added to the annual operating and maintenance costs of the requirements to get the total annualized costs without product recovery in each year.

The value of product recovery is then subtracted to get the total annualized costs with product recovery in each year. Under this proposal, over 90 percent of revenue from the sale of captured natural gas is projected to be earned by operators in the production and processing segments of the industry, where we assume that the operators own the natural gas and will receive the financial benefit from the captured natural gas. The remainder of the captured natural gas is captured within the transmission and storage segment, where operators do not typically own the natural gas they transport; rather, they receive payment for the transportation service they provide. In the RIA, we treat these revenues as an offset to projected compliance costs, while the revenues may also be considered as a benefit of the regulatory action. However, regardless of whether the revenue from capture of natural gas is considered a compliance cost offset or a benefit, the net benefits are equivalent.

We now present the compliance costs of the proposed NSPS OOOOb and EG OOOOc in a PV framework. The stream of the estimated costs for each year from 2023 through 2035 is discounted back to 2021 using 3 and 7 percent discount rates and summed to get the PV of the costs. The PV is then used to estimate the EAV of the estimated costs. The EAV is the single annual value which, if summed in PV terms across years in the analytical time frame, equals the PV of the original (i.e., likely time-varying) stream of costs. In other words, the EAV takes the potentially “lumpy” stream of costs and converts them into a single value that, when discounted and added together over each period in the analysis time frame, equals the original stream of values in PV terms.

Table 2-9 shows the undiscounted stream of costs for each year from 2023 through 2035 due to the proposed standards. Capital costs are the projected capital and planning costs expected to be incurred. Total costs are the sum of the capital costs and annual operating costs. The revenue from the increase in product recovery is estimated using the AEO2021 natural gas price projections, as described earlier. Total costs with revenue from product recovery equal the total anticipated costs minus the revenue.

Table 2-9 Undiscounted Projected Compliance Costs under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions 2019$)

Year	Capital Costs	Annual Operating Costs	Total Costs (w/o Revenue)	Revenue from Product Recovery	Total Costs (with Revenue)
2023	$150	($3.7)	$150	$22	$130
2024	$170	($5.0)	$160	$30	$130
2025	$180	($6.5)	$180	$41	$130
2026	$780	$1,200	$2,000	$730	$1,200
2027	$760	$1,100	$1,900	$730	$1,200
2028	$740	$1,100	$1,800	$740	$1,100
2029	$730	$1,000	$1,800	$740	$1,000
2030	$710	$990	$1,700	$730	$970
2031	$700	$940	$1,600	$720	$920
2032	$680	$900	$1,600	$710	$870
2033	$670	$860	$1,500	$700	$820
2034	$660	$820	$1,500	$690	$780
2035	$650	$780	$1,400	$680	$750

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

Table 2-10 shows the discounted stream of costs discounted to 2021 using a 3 and 7 percent discount rate. The PV of the stream of costs discounted to 2021 using a 3 percent discount rate is $13 billion, with an EAV of $1.2 billion per year. The PV of the stream of costs discounted to 2021 using a 7 percent discount rate is $10 billion, with an EAV of $1.2 billion per year.

Table 2-10 Discounted Projected Costs under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions 2019$)

Year	3 Percent			7 Percent		
	Total Annual Cost (w/o Product Recovery Revenue)	Revenue from Product Recovery	Total Annual Costs (w/ Product Recovery Revenue)	Total Annual Cost (w/o Product Recovery Revenue)	Revenue from Product Recovery	Total Annual Cost (w/ Product Recovery Revenue)
2023	$18	$21	($2.6)	$24	$19	$4.2
2024	$26	$28	($1.5)	$32	$25	$7.7
2025	$34	$36	($2.8)	$40	$31	$8.7
2026	$1,700	$630	$1,100	$1,600	$520	$1,000
2027	$1,600	$610	$970	$1,400	$480	$920
2028	$1,500	$600	$880	$1,300	$460	$810
2029	$1,400	$580	$790	$1,100	$430	$710
2030	$1,300	$560	$720	$1,000	$400	$630
2031	$1,200	$530	$670	$920	$360	$560
2032	$1,100	$510	$610	$830	$340	$490
2033	$1,000	$490	$550	$750	$310	$430
2034	$980	$470	$510	$670	$290	$390
2035	$920	$450	$470	$610	$260	$340
PV	**$13,000**	**$5,500**	**$7,200**	**$10,000**	**$3,900**	**$6,300**
EAV	**$1,200**	**$520**	**$680**	**$1,200**	**$470**	**$760**

Note: Values rounded to two significant figures. Sums may not appear to add correctly due to rounding. Costs and revenue from product recovery in each year are discounted to 2021.

2.6 Detailed Impacts Table

The following table shows the total emissions reductions and the PV and EAV of net compliance costs over the 2023 to 2035 period. The projected net compliance costs for two of the affected source types, natural gas processing plants and reciprocating compressors, are negative. The net compliance costs for leak detection at natural gas processing plants is primarily because OGI surveys under this proposal can be conducted much more quickly and at approximately half the cost of EPA Method 21 surveys under the current requirements in NSPS VVa, so the increased flexibility under the proposal is likely cost saving for affected facilities. Additionally, both EPA Method 21 and OGI LDAR programs reduce loss of product. Therefore, the costs of the LDAR programs are offset to some degree to the emissions reduced.

For reciprocating compressors, the projected revenue from product recovery exceeds the projected cost reductions. This observation may typically support an assumption that operators would continue to perform the emissions abatement activity, regardless of whether a requirement is in place, because it is in their private self-interest. However, many of the reciprocating compressors are in the transmission and storage segment. As discussed in previous oil and natural gas NSPS RIAs, operators in the transmission and storage segment of the industry do not typically own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, financial incentives to reduce emissions may be minimal because operators are not able to recoup the financial value of captured natural gas that may otherwise be emitted. Alternatively, there may also be an opportunity cost associated with the installation of environmental controls (for purposes of mitigating the emission of pollutants) that is not reflected in the control costs. In the event that the environmental investment displaces investment in productive capital, the difference between the rate of return on the marginal investment displaced by the mandatory environmental investment is a measure of the opportunity cost of the environmental requirement to the regulated entity. However, if firms are not capital constrained, then there may not be any displacement of investment, and the rate of return on other investments in the industry would not be relevant as a measure of opportunity cost. If firms should face higher borrowing costs as they take on more debt, there may be an additional opportunity cost to the firm**.** To the extent that any opportunity costs are not added to the control costs, the compliance cost reductions presented above may be underestimated.

Table 2-11 Projected Emissions Reductions and Compliance Costs for Incrementally Affected Sources (millions 2019$) under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023 to 2035

	Nationwide Emissions Reductions				Net Compliance Cost	
Source	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO2e)**	**PV**	**EAV**
Well Site Fugitives	13,000,000	3,700,000	140,000	300,000,000	$2,600	$320
Gathering and Boosting Station Fugitives	410,000	110,000	4,300	9,200,000	$180	$22
Transmission and Storage Compressor Station Fugitives	810,000	22,000	660	18,000,000	$120	$15
Natural Gas Processing Plant Equipment Leaks	240,000	23,000	840	5,400,000	-$67	-$8
Pneumatic Pumps	970,000	270,000	10,000	22,000,000	$140	$17
Pneumatic Controllers	19,000,000	5,200,000	190,000	440,000,000	$2,400	$280
Reciprocating Compressors	3,500,000	620,000	23,000	78,000,000	-$81	-$10
Centrifugal Compressors	1,700,000	250,000	36,000	38,000,000	$740	$88
Liquids Unloading	160,000	45,000	1,700	3,700,000	$41	$5
Storage Vessels	400,000	1,800,000	69,000	9,100,000	$260	$31

Note: Values rounded to two significant figures.

2.7 Comparison of Regulatory Alternatives

In this section, we compare the compliance cost and emissions impacts projected under the primary proposal with the results of the co-proposed option and the impacts of two alternative regulatory scenarios, one less stringent and one more stringent than the proposed rule. The alternative scenarios focus on the sources that account for the largest number of estimated emissions reductions of methane and/or VOC for the proposed rule: well site fugitives, pneumatic controllers at well sites, and storage vessels.

The alternative scenarios are summarized in Table 2-12. In the less stringent scenario, well site fugitives monitoring frequency for the highest emitting bin is reduced to semiannual (as opposed to quarterly) for both the NSPS OOOOb and EG OOOOc, which matches the current NSPS OOOOa for that bin. In the more stringent scenario, the lowest emitting bin is also required to perform semiannual monitoring, while the monitoring frequency for the highest emitting bin is increased to monthly. For pneumatic controllers, the less stringent alternative simply extends the current NSPS of an emissions limit for continuous-bleed controllers to pre-OOOO (for well sites and gathering and boosting stations) or pre-OOOOa (for transmission and storage compressor stations) sources. The proposed options and more stringent alternative require zero-emitting controllers. Finally, for storage vessels, the less stringent alternative assumes a 50 tpy methane (instead of 20 tpy) threshold for pre-OOOO sources, while the proposed options and more stringent alternative assume a 20 tpy methane threshold.

Table 2-12 Summary of Regulatory Alternatives

Source	BSER				
	Baseline	**Less Stringent**	**Co-Proposal**	**Primary Proposal**	**More Stringent**
Fugitive Emissions at Well Sites					
Bin 1: 0 – 3 tpy	Semiannual OGI	Verify baseline methane emissions	Verify baseline methane emissions	Verify baseline methane emissions	Semiannual OGI
Bin 2: 3 – 8 tpy	Semiannual OGI	Semiannual OGI	Semiannual OGI	Quarterly OGI	Quarterly OGI
Bin 3: 8+ tpy	Semiannual OGI	Semiannual OGI	Quarterly OGI	Quarterly OGI	Monthly OGI
Pneumatic Controllers					
Well Sites and Gathering and Boosting Stations					
Pre-OOOO	No requirement	Emissions limit	Non-emitting	Non-emitting	Non-emitting
Post-OOOO	Emissions limit	Emissions limit	Non-emitting	Non-emitting	Non-emitting
Transmission and Storage Compressor Stations					
Pre-OOOOa	No requirement	Emissions limit	Non-emitting	Non-emitting	Non-emitting
Post-OOOOa	Emissions limit	Emissions limit	Non-emitting	Non-emitting	Non-emitting
Storage Vessels					
Pre-OOOO	No requirement	95% control if PTE > 50 tpy CH_4	95% control if PTE > 20 tpy CH_4	95% control if PTE > 20 tpy CH_4	95% control if PTE > 20 tpy CH_4

A comparison of estimated costs and emissions reductions is presented in Table 2-13 for three years: 2023 (first year of NSPS OOOOb impacts), 2026 (first year of EG OOOOc impacts), and 2035 (last year of analysis). Overall, the table demonstrates that we estimate the impacts of the EG OOOOc to be much greater than those of the NSPS OOOOb for all regulatory alternatives. By the time the EG OOOOc is assumed to begin having an effect in 2026, we estimate that the less stringent option would result in more than one-quarter fewer methane and VOC emissions reductions than the co-proposed options, while reducing costs in the neighborhood of five to ten percent, depending on whether revenue from gas recovery is taken into account. On the other hand, we estimate that the more stringent option would result in around 7–11 percent more methane and VOC emissions reductions than the co-proposed options, while increasing costs by a substantially greater proportion, regardless of whether revenue from gas recovery is taken into account.

Table 2-13 Comparison of Regulatory Alternatives in 2023, 2026, and 2035 for the Proposed NSPS OOOOb and EG OOOOc (millions 2019$)

	Regulatory Alternative			
	Less Stringent	Co-Proposal	Primary Proposal	More Stringent
		Total Impacts, 2023		
Emissions reductions				
Methane (short tons)	23,000	130,000	130,000	140,000
VOC (short tons)	9,000	38,000	39,000	42,000
Costs				
Annualized Costs without Product Recovery (3%)	$7.70	$13	$19	$46
Annualized Costs with Product Recovery (3%)	$5.00	($7.80)	($2.80)	$22
		Total Impacts, 2026		
Emissions reductions				
Methane (short tons)	3,100,000	4,300,000	4,500,000	4,800,000
VOC (short tons)	950,000	1,300,000	1,400,000	1,400,000
Costs				
Annualized Costs without Product Recovery (3%)	$1,700	$1,800	$2,000	$2,700
Annualized Costs with Product Recovery (3%)	$1,200	$1,100	$1,200	$2,000
		Total Impacts, 2035		
Emissions reductions				
Methane (short tons)	2,200,000	3,400,000	3,600,000	3,800,000
VOC (short tons)	650,000	1,000,000	1,000,000	1,100,000
Costs				
Annualized Costs without Product Recovery (3%)	$1,200	$1,200	$1,400	$2,000
Annualized Costs with Product Recovery (3%)	$770	$590	$710	$1,300

3 BENEFITS

The proposed NSPS OOOOb and EG OOOOc are projected to reduce methane, VOC, and HAP emissions.[41] The total emissions reductions over the 2023–2035 period are estimated to be about 41 million short tons of methane, 12 million tons of VOC, and 0.48 million tons of HAP. The decrease in methane emissions in CO_2-equivalent (CO_2 Eq.) terms is estimated to be about 920 million metric tons using a global warming potential of 25.

We monetize the impacts of methane reductions in this RIA. We estimate the climate benefits under the proposal using an interim global measure of the social cost of methane (SC-CH_4), as presented in Section 3.2.

In addition to presenting monetized estimates of impacts from methane reductions, we also provide a qualitative discussion of potential climate, human health, and welfare impacts of emissions reductions we are unable to quantify and monetize. Table 3-1 summarizes the quantified and unquantified benefits in this analysis. We also present a supplemental illustrative screening analysis of quantified and monetized ozone-related health impacts of VOC reductions based on a national benefit-per-ton methodology in Appendix B.

[41] Some control techniques of the proposed action, such as routing emission to combustion devices, are also anticipated to have minor disbenefits resulting from secondary emissions of carbon dioxide (CO_2), nitrogen oxides (NO_X), PM, carbon monoxide (CO), and total hydrocarbons (THC).

Table 3-1 Climate and Human Health Effects of the Projected Emissions Reductions from this Proposal

Category	Effect	Effect Quantified	Effect Monetized	More Information
Environment				
Climate effects	Climate impacts from methane (CH_4)	—[a]	✓	Section 3.3
	Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts)	—	—	IPCC, Ozone ISA, PM ISA
Human Health				
Mortality from exposure to ozone[42]	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[43]	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[b]
	Metabolic effects (e.g., diabetes)	—	—	Ozone ISA[b]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[b]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[b]
	Reproductive and developmental effects	—	—	Ozone ISA[b]
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

[42] We present a supplemental illustrative analysis of quantified and monetized ozone-related health impacts of VOC reductions based on a national benefit-per-ton methodology in Appendix B.

[43] Ibid.

Category	Effect	Effect Quantified	Effect Monetized	More Information
Nonfatal morbidity from exposure to $PM_{2.5}$	Heart attacks (age > 18)	—	—	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)	—	—	PM ISA
	Stroke (ages 65-99)	—	—	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[b]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[b]
	Other nervous system effects (e.g., autism, cognitive decline, dementia)	—	—	PM ISA[b]
	Metabolic effects (e.g., diabetes)	—	—	PM ISA[b]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)	—	—	PM ISA[b]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[b]

Category	Effect	Effect Quantified	Effect Monetized	More Information
Incidence of morbidity from exposure to HAP	Effects associated with exposure to hazardous air pollutants such as benzene	—	—	ATSDR, IRIS[c,d]

[a] The global climate and related impacts of CH_4 emissions changes, such as sea level rise, are estimated within each integrated assessment model as part of the calculation of the SC-CH_4. The resulting monetized damages, which are relevant for conducting the benefit-cost analysis, are used in this RIA to estimate the welfare effects of quantified changes in methane emissions.
[b] Not quantified due to data availability limitations and/or because current evidence is only suggestive of causality.
[c] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.
[d] We assess these benefits qualitatively due to data limitations for this analysis, but we have quantified them in other analyses.

3.1 Emissions Reductions

Oil and natural gas operations in the U.S. include a variety of emission sources for methane, VOC, and HAP, including wells, well sites, processing plants, compressor stations, storage equipment, and natural gas transmission and distribution lines. These emission points are located throughout much of the country, though many of these emissions sources are concentrated in particular geographic regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas natural gas compressor stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

Table 3-2 shows the emissions reductions projected under the proposed NSPS OOOOb and EG OOOOc over the 2023–2035 period. We present methane emissions in both short tons and CO_2 Eq. using a global warming potential of 25. The impacts of these pollutants accrue at different spatial scales. HAP emissions increase exposure to carcinogens and other toxic pollutants primarily near the emission source. VOC emissions are precursors to secondary formation of $PM_{2.5}$ and ozone on a broader regional scale. Climate effects associated with long-lived greenhouse gases like methane generally do not depend on the location of the emission of the gas and have global impacts. Methane is also a precursor to global background concentrations of ozone.

Table 3-2 Projected Annual Reductions of Methane, VOC, and HAP Emissions under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035

Year	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)
2023	130,000	39,000	1,500	3,100,000
2024	200,000	57,000	2,200	4,500,000
2025	260,000	75,000	2,800	5,900,000
2026	4,500,000	1,400,000	54,000	100,000,000
2027	4,400,000	1,300,000	52,000	100,000,000
2028	4,300,000	1,300,000	51,000	97,000,000
2029	4,200,000	1,200,000	49,000	94,000,000
2030	4,000,000	1,200,000	48,000	92,000,000
2031	3,900,000	1,200,000	46,000	89,000,000
2032	3,800,000	1,100,000	45,000	87,000,000
2033	3,700,000	1,100,000	44,000	85,000,000
2034	3,700,000	1,100,000	43,000	83,000,000
2035	3,600,000	1,000,000	42,000	81,000,000
Total	**41,000,000**	**12,000,000**	**480,000**	**920,000,000**

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

3.2 Methane Climate Effects and Valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone, which also impacts global temperatures. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice sheets, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

According to the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (IPCC, 2021), radiative forcing due to methane relative to 1750 was 0.54 W/m^2 in 2019, which is about 16 percent of all global forcing due to increases in anthropogenic GHG concentrations, and which makes methane the second leading long-lived climate forcer after CO_2.[44] After accounting

[44] Increased concentrations of methane and other well mixed greenhouse gases in the atmosphere absorb thermal infrared emission energy, reducing the rate at which the Earth can cool through radiating heat to space. Radiative forcing, measured as watts per square meter (W/m^2), is a measure of the climate impact of greenhouse gases and other human activities.

for changes in other greenhouse substances such as ozone and stratospheric water vapor due to chemical reactions of methane in the atmosphere, historical methane emissions account for about 0.5 degrees of warming today, or about one third of the total warming resulting from historical emissions of well-mixed GHGs.

The oil and natural gas sector emits significant quantities of methane. The U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990–2019 (published 2021) estimates 2019 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries, petroleum transportation, and natural gas distribution) to be 187 million metric tons CO_2 Eq. In 2019, total methane emissions from the oil and natural gas industry represented 27 percent of the total methane emissions from all sources and account for about 3 percent of all CO_2 Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2021d).

We estimate the global social benefits of CH_4 emissions reductions expected from this proposed rule using the SC-CH_4 estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* published in February 2021 by the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) (IWG, 2021). The SC-CH_4 is the monetary value of the net harm to society associated with a marginal increase in emissions in a given year, or the benefit of avoiding that increase. In principle, SC-CH_4 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-CH_4 therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton. The SC-CH_4 is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CH_4 emissions. As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, the EPA agrees that the interim SC-GHG estimates represent the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the latest, peer-reviewed science.

The $SC\text{-}CH_4$ 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 social cost of carbon ($SC\text{-}CO_2$) values used across agencies. The IWG published $SC\text{-}CO_2$ 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.[45] In August 2016 the IWG published estimates of the social cost of methane ($SC\text{-}CH_4$) and nitrous oxide ($SC\text{-}N_2O$) using methodologies that are consistent with the methodology underlying the $SC\text{-}CO_2$ estimates. The modeling approach that extends the IWG $SC\text{-}CO_2$ methodology to non-CO_2 GHGs has undergone multiple stages of peer review. The $SC\text{-}CH_4$ and $SC\text{-}N_2O$ estimates were developed by Marten et al. (2015) and underwent a standard double-blind peer review process prior to journal publication. The EPA then sought additional external peer review of technical issues associated with its application to regulatory analysis. Following the completion of the independent external peer review of the application of the Marten et al. (2015) estimates, the EPA began using the estimates in the primary benefit-cost analysis calculations and tables for a number of proposed rulemakings in 2015. The EPA considered and responded to public comments received for the proposed rulemakings before using the estimates in final regulatory analyses in 2016.[46] In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the $SC\text{-}CO_2$ estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the $SC\text{-}CO_2$ estimates to offer advice on how

[45] 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).

[46] See IWG (2016b) for more discussion of the $SC\text{-}CH_4$ and $SC\text{-}N_2O$ and the peer review and public comment processes accompanying their development.

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). Shortly thereafter, in March 2017, President Trump issued EO 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" (EO 13783, Section 5(c)). Benefit-cost analyses following EO 13783, including the benefit-cost analysis in the Safer Affordable Fuel-Efficient (SAFE) rule RIA,[47] 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 EO 13990, which re-established the IWG and directed it to ensure that the U.S. Government's estimates of the social cost of carbon and other greenhouse gases reflect the best available science and the recommendations of 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 EO that reflect the full impact of GHG emissions, including by taking global damages into account. The interim SC-GHG estimates published in February 2021, specifically the SC-CH_4 estimates, are used here to estimate the climate benefits for this proposed rulemaking. The EO instructs the IWG to undertake a fuller update of the SC-GHG estimates by January 2022 that takes into consideration the advice of National Academies (2017) and other recent scientific literature.

[47] The values used in the SAFE rule RIA were interim values developed under EO 13783 for use in regulatory analyses. EPA followed EO 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.

The February 2021 SC-GHG TSD provides a complete discussion of the IWG's initial review conducted under EO 13990. In particular, the IWG found that the SC-GHG estimates used under EO 13783 fail to reflect the full impact of GHG emissions in multiple ways. First, the IWG 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. As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, EPA agrees with this assessment and, therefore, in this proposed rule the EPA centers attention on a global measure of SC-CH_4. This approach is the same as that taken in EPA regulatory analyses over 2009 through 2016. As noted in the February 2021 SC-GHG 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, the EPA will 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 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; IWG, 2013; IWG, 2016a; IWG, 2016b), and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates.[48] As a

[48] GHG emissions are stock pollutants, with damages associated with what has accumulated in the atmosphere over time, and they are long lived such that subsequent damages resulting from emissions today occur over many

member of the IWG involved in the development of the February 2021 SC-GHG TSD, the 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 SC-GHG 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 percent, 3 percent, and 5 percent), 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 percent estimate of the discount rate. As explained in the February 2021 SC-GHG TSD, and EPA agrees, 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 3-3 summarizes the interim global SC-CH_4 estimates across all the model runs for each discount rate for emissions occurring in 2023 to 2035. These estimates are reported in 2019 dollars but are otherwise identical to those presented in the IWG's 2016 TSD (IWG 2016b). For

decades or centuries depending on the specific greenhouse gas under consideration. In calculating the SC-GHG, the stream of future damages to agriculture, human health, and other market and non-market sectors from an additional unit of emissions are estimated in terms of reduced consumption (or consumption equivalents). Then that stream of future damages is discounted to its present value in the year when the additional unit of emissions was released. Given the long time horizon over which the damages are expected to occur, the discount rate has a large influence on the present value of future damages.

purposes of capturing uncertainty around the SC-CH_4 estimates in analyses, the IWG's February 2021 SC-GHG TSD emphasizes the importance of considering all four of the SC-CH_4 values. The SC-CH_4 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. There are a number of limitations and uncertainties associated with the SC-CH_4 estimates presented in Table 3-3. Some uncertainties are captured within the analysis, while other areas of uncertainty have not yet been quantified in a way that can be modeled.

Table 3-3 Interim Global Social Cost of CH_4, 2023–2035 (in 2019$ per metric ton CH_4)

Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2023	$750	$1,600	$2,100	$4,300
2024	$770	$1,700	$2,200	$4,400
2025	$800	$1,700	$2,200	$4,500
2026	$830	$1,800	$2,300	$4,700
2027	$860	$1,800	$2,300	$4,800
2028	$880	$1,900	$2,400	$4,900
2029	$910	$1,900	$2,500	$5,100
2030	$940	$2,000	$2,500	$5,200
2031	$970	$2,000	$2,600	$5,300
2032	$1,000	$2,100	$2,600	$5,500
2033	$1,000	$2,100	$2,700	$5,700
2034	$1,100	$2,200	$2,800	$5,800
2035	$1,100	$2,200	$2,800	$6,000

Source: Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990 (IWG, 2021).
Note: These SC-CH_4 values are identical to those reported in the 2016 TSD (IWG, 2016b) adjusted for inflation to 2019 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 CH_4 and vary depending on the year of CH_4 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/.

Figure 3-1 presents the quantified sources of uncertainty in the form of frequency distributions for the SC-CH_4 estimates for emissions in 2030. The distribution of SC-CH_4 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-CH_4 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-CH_4. This is because GHG 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.

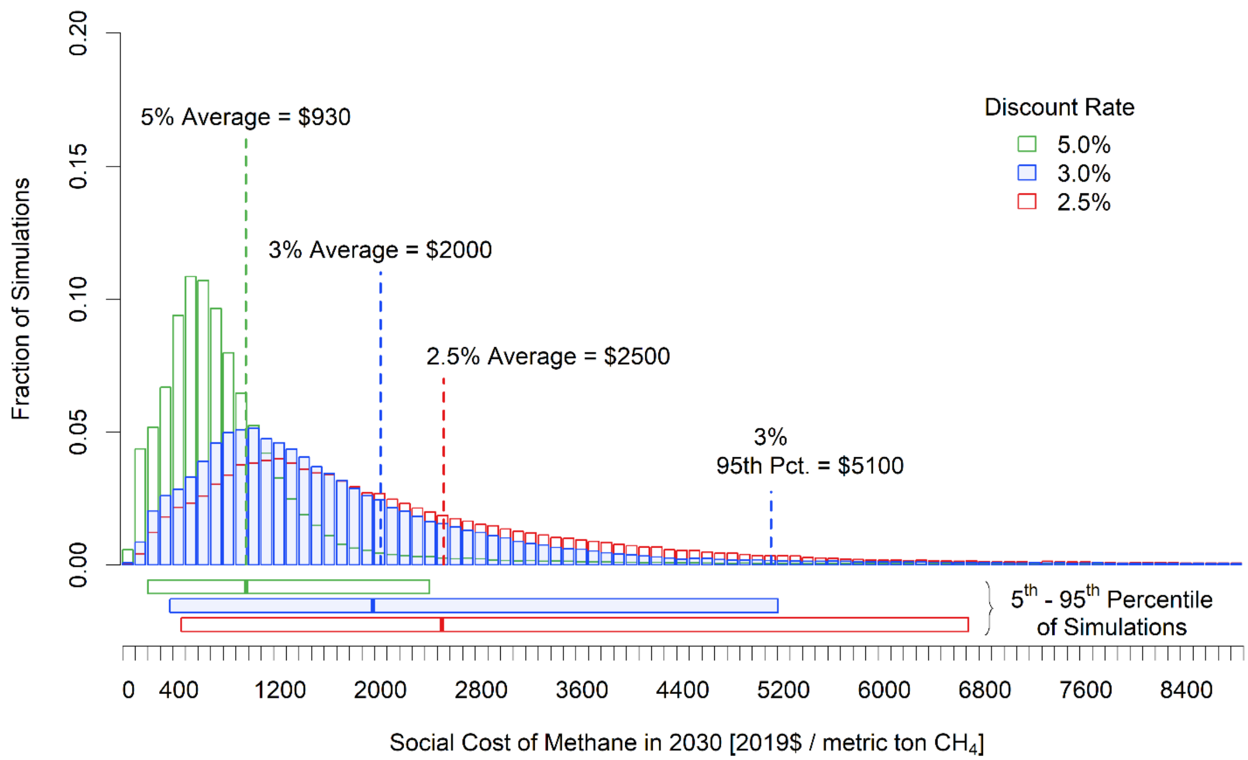

Figure 3-1 Frequency Distribution of SC-CH_4 Estimates for 2030[49]

The interim SC-CH_4 estimates presented in Table 3-3 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

[49] Although the distributions and numbers in Figure 3-1 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 0.029 percent of the estimates falling below the lowest bin displayed and 3 percent of the estimates falling above the highest bin displayed.

"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 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-GHG estimates. However, the IWG has recommended that, taken together, the limitations suggest that the interim SC-GHG estimates used in this proposed rule likely underestimate the damages from GHG 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-CO2 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; IPCC, 2019a; IPCC, 2019b); U.S. Global Change Research Program (USGCRP, 2016; USGCRP, 2018); and the National Academies of Sciences, Engineering, and Medicine (National Academies, 2017; National Academies, 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-GHG estimates.

There are several limitations specific to the estimation of SC-CH_4. For example, the SC-CH_4 estimates do not reflect updates from the IPCC regarding atmospheric and radiative efficacy. Another limitation is that the SC-CH_4 estimates do not account for the direct health and welfare impacts associated with tropospheric ozone produced by methane (see the 2016 NSPS RIA for further discussion). In addition, the SC-CH_4 estimates do not reflect that methane emissions lead to a reduction in atmospheric oxidants, like hydroxyl radicals, nor do they account for impacts associated with CO_2 produced from methane oxidizing in the atmosphere. See EPA-HQ-OAR-2015-0827-5886 for more detailed discussion about the limitations specific to the estimation of SC-CH_4. These individual limitations and uncertainties do not all work in the same direction in terms of their influence on the SC-CH_4 estimates.

Table 3-4 presents the undiscounted annual monetized global climate benefits under the proposed NSPS OOOOb and EG OOOOc. Projected methane emissions reductions each year are multiplied by the SC-CH_4 estimate for that year. Table 3-5 shows the annual global climate benefits discounted back to 2021 and the PV and the EAV for the 2023–2035 period under each discount rate.

Table 3-4 Undiscounted Projected Global Climate Benefits under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions, 2019$)[a,b]

Year	Undiscounted			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2023	$91	$200	$260	$520
2024	$140	$300	$390	$790
2025	$190	$400	$520	$1,100
2026	$3,400	$7,200	$9,400	$19,000
2027	$3,400	$7,200	$9,300	$19,000
2028	$3,400	$7,200	$9,300	$19,000
2029	$3,400	$7,200	$9,200	$19,000
2030	$3,400	$7,200	$9,200	$19,000
2031	$3,500	$7,200	$9,200	$19,000
2032	$3,500	$7,200	$9,200	$19,000
2033	$3,500	$7,200	$9,200	$19,000
2034	$3,600	$7,200	$9,200	$19,000
2035	$3,600	$7,200	$9,200	$19,000

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 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.

[b] 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-GHG estimates used in regulatory analysis under revoked EO 13783 were an approximation of the climate damages occurring within U.S. borders only. Applying the same methodology to the SC-CH_4 estimates used in this RIA yields an approximation of the climate damages occuring within U.S. borders only from a ton of CH_4 emissions. These estimates range from $207 using a 3 percent discount rate for emissions occurring in 2023 to $283 using a 3 percent discount rate for emissions occurring in 2035. Applying these estimates (based on a 3 percent discount rate) to the CH_4 emissions reduction expected under the proposed rule would yield benefits from climate impacts within U.S. borders of $25 million in 2023, increasing to $920 million in 2035. 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 GHG 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.

Table 3-5 **Discounted Projected Global Climate Benefits under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions, 2019$)**[a]

Year	Discounted back to 2021			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2023	$83	$190	$250	$490
2024	$120	$270	$360	$720
2025	$150	$360	$470	$950
2026	$2,700	$6,300	$8,300	$17,000
2027	$2,500	$6,100	$8,000	$16,000
2028	$2,400	$5,900	$7,800	$16,000
2029	$2,300	$5,700	$7,600	$15,000
2030	$2,200	$5,500	$7,400	$15,000
2031	$2,100	$5,300	$7,200	$14,000
2032	$2,100	$5,200	$7,000	$14,000
2033	$2,000	$5,100	$6,800	$13,000
2034	$1,900	$4,900	$6,700	$13,000
2035	$1,800	$4,800	$6,500	$13,000
PV	**$22,000**	**$55,000**	**$74,000**	**$150,000**
EAV	**$2,400**	**$5,200**	**$6,800**	**$14,000**

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 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.
Note: Estimates may not sum due to independent rounding.

3.3 Ozone-Related Impacts Due to VOC Emissions

This proposed rulemaking is projected to reduce VOC emissions, which are a precursor to ozone. Ozone is not generally emitted directly into the atmosphere but is created when its two primary precursors, VOC and oxides of nitrogen (NO_X), react in the atmosphere in the presence of sunlight. In urban areas, compounds representing all classes of VOC can be important for ozone formation, but biogenic VOC emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2013). Recent observational and modeling studies have found that VOC emissions from oil and natural gas operations can impact ozone levels (McDuffie et al., 2016; Benedict et al., 2019; Lindaas et al., 2019; Tzompa-Sosa and Fischer, 2020). Emissions reductions may decrease ozone formation, human exposure to ozone, and the incidence of ozone-related health effects.

Calculating ozone impacts from changes in VOC emissions requires information about the spatial patterns in those emissions changes. In addition, the ozone health effects from the proposed rule will depend on the relative proximity of expected VOC and ozone changes to population. In this analysis, we have not characterized VOC emissions changes at a finer spatial resolution than the national total due to data and resource constraints. In light of these limitations, we present an illustrative screening analysis of ozone-related health benefits in Appendix B based on modeled oil and natural gas VOC contributions to ozone concentrations as they occurred in 2017 and do not include the results of this screening analysis in the estimate of benefits (and net benefits) projected from this proposal. To more definitively analyze the impacts of VOC reductions from this proposed rule on ozone health benefits, we would need credible projections of spatial patterns of expected VOC emissions reductions. Similarly, due to the high degree of variability in the responsiveness of ozone formation to VOC emissions reductions, we are unable to determine how this rule might affect air quality in downwind ozone nonattainment areas without modeling air quality changes. However, we note that in future regulatory impact analyses supporting other regulations, the EPA plans to account for the emissions impacts of the oil and natural gas NSPS OOOOb and EG OOOOc in the baseline for the analysis.

3.3.1 Ozone Health Effects

Human exposure to ambient ozone concentrations is associated with adverse health effects, including premature respiratory mortality and cases of respiratory morbidity (U.S. EPA, 2020a). Researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical, and epidemiological studies (U.S. EPA, 2020a). When adequate data and resources are available, the EPA has generally quantified several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010; U.S. EPA, 2011b; U.S. EPA, 2021). These health effects include respiratory morbidity, such as asthma attacks, hospital and emergency department visits, lost school days, and premature respiratory mortality. The scientific literature is also suggestive that exposure to ozone is associated with chronic respiratory damage and premature aging of the lungs.

3.3.2 Ozone Vegetation Effects

Exposure to ozone has been found to be associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2020a). Sensitivity to ozone is highly variable across species, with over 66 vegetation species identified as “ozone-sensitive,” many of which occur in state and national parks and forests. These effects include those that cause damage to, or impairment of, the intended use of the plant or ecosystem. Such effects are considered adverse to public welfare and can include reduced growth and/or biomass production in sensitive trees, reduced yield and quality of crops, visible foliar injury, changed to species composition, and changes in ecosystems and associated ecosystem services.

3.3.3 Ozone Climate Effects

Ozone is a well-known short-lived climate forcing GHG (U.S. EPA, 2013). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). The IPCC AR5 estimated that the contribution to current warming levels of increased tropospheric ozone concentrations resulting from human methane, NO_X, and VOC emissions was 0.5 W/m^2, or about 30 percent as large a warming influence as elevated CO_2 concentrations. This quantifiable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles.

3.4 Ozone-Related Impacts Due to Methane

The tropospheric ozone produced by the reaction of methane in the atmosphere has harmful effects for human health and plant growth in addition to its climate effects (Nolte, 2018). In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2013). Approximately 50 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane (Myhre et al., 2013). Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future (Myhre et al., 2013). Unlike NO_X and VOC, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane's long atmospheric lifetime when compared to these other ozone precursors (Myhre et al., 2013). Reducing methane emissions, therefore, will contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects (USGCRP, 2018). The benefits of such reductions are global and occur in both urban and rural areas.

3.5 $PM_{2.5}$-Related Impacts Due to VOC Emissions

This proposed rulemaking is expected to result in emissions reductions of VOC, which are a precursor to $PM_{2.5}$, thus decreasing human exposure to $PM_{2.5}$ and the incidence of $PM_{2.5}$-related health effects, although the magnitude of this effect has not been quantified at this time. Most VOC emitted are oxidized to CO_2 rather than to PM, but a portion of VOC emissions contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2019). Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution (U.S. EPA, 2019). The potential for an organic compound to partition into the particle phase is highly dependent on its volatility such that compounds with lower volatility are more prone to partition into the particle phase and form SOA (Jimenez et al., 2009; Cappa and Wilson, 2012; Donahue et al., 2012). Hydrocarbon emissions from oil and natural gas operations tend to be dominated by high volatility, low-carbon number compounds that are less likely to form SOA (Pétron et al., 2012; Helmig et al., 2014; Koss et al., 2017). Given that only a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions, and the relatively volatile nature of VOCs emitted from this sector, it is unlikely that the VOC emissions reductions projected to occur under this proposal would have a large contribution to ambient secondary organic carbon aerosols. Therefore, we have not quantified the $PM_{2.5}$-related benefits in this analysis. Moreover, without modeling air quality changes, we are unable to determine how this rule might affect air quality in downwind $PM_{2.5}$ nonattainment areas. However, we note that in future regulatory impact analyses supporting other regulations, the EPA plans to account for the emissions impacts of the oil and natural gas NSPS OOOOb and EG OOOOc in the baseline for the analysis.

3.5.1 $PM_{2.5}$ Health Effects

Decreasing exposure to $PM_{2.5}$ is associated with significant human health benefits, including reductions in respiratory mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$

exposure with adverse health effects in numerous toxicological, clinical, and epidemiological studies (U.S. EPA, 2019). These health effects include asthma development and aggravation, decreased lung function, and increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing (U.S. EPA, 2019). These health effects result in hospital and ER visits, lost workdays, and restricted activity days. When adequate data and resources are available, the EPA has quantified the health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA, 2021f).

When the EPA quantifies $PM_{2.5}$-related benefits, the Agency assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2019). Based on our review of the current body of scientific literature, the EPA estimates PM-related premature mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

3.5.2 PM Welfare Effects

Suspended particles and gases degrade visibility by scattering and absorbing light. Decreasing secondary formation of $PM_{2.5}$ from VOC emissions could improve visibility throughout the U.S. Visibility impairment has a direct impact on 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. Previous analyses (U.S. EPA, 2006; U.S. EPA, 2011b; U.S. EPA, 2011c; U.S. EPA, 2012b) show that visibility benefits are a significant welfare benefit category. However, without air quality modeling of $PM_{2.5}$ impacts, we are unable to estimate visibility related benefits.

Separately, persistent and bioaccumulative HAP reported as emissions from oil and natural gas operations, including polycyclic organic matter, could lead to PM welfare effects. Several significant ecological effects are associated with the deposition of organic particles, including persistent organic pollutants and PAHs (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. (U.S. EPA, 2012b).

3.6 Hazardous Air Pollutants (HAP) Impacts

Available emissions data show that several different HAP are emitted from oil and natural gas operations. The HAP emissions from the oil and natural gas sector in the 2017 National Emissions Inventory (NEI) emissions data are summarized in Table 3-6. The table includes either oil and natural gas nonpoint or oil and natural gas point emissions of at least 10 tons per year, in descending order of annual nonpoint emissions. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and natural gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2011d).

Table 3-6 Top Annual HAP Emissions as Reported in 2017 NEI for Oil and Natural Gas Sources

Pollutant	Nonpoint Emissions (tons/year)	Point Emissions (tons/year)
Benzene	26,869	502
Xylenes (Mixed Isomers)	25,410	506
Formaldehyde	23,413	222
Toluene	18,054	823
Acetaldehyde	2,722	26
Hexane	2,675	886
Ethyl Benzene	2,021	113
Acrolein	1,602	18
Methanol	1,578	342
1,3-Butadiene	337	5.80E-01
2,2,4-Trimethylpentane	252	46
Naphthalene	104	1.10E+00
Propionaldehyde	102	0.00E+00
PAH/POM - Unspecified	68	2.50E-02
1,1,2-Trichloroethane	25	1.40E-03
Methylene Chloride	22	8.70E-02
1,1,2,2-Tetrachloroethane	14	1.90E-03
Ethylene Dibromide	13	1.90E-03
Methyl Tert-Butyl Ether	0	17.30

In the subsequent sections, we describe the health effects associated with the main HAP of concern from the oil and natural gas sector: benzene (Section 3.6.1), formaldehyde (Section

3.6.2), toluene (Section 3.6.3), carbonyl sulfide (Section 3.6.4), ethylbenzene (Section 3.6.5), mixed xylenes (Section 3.6.6), and n-hexane (Section 3.6.7), and other air toxics (Section 3.6.8). This proposal is projected to reduce 280,000 tons of HAP emissions over the 2023 through 2035 period.[50] With the data available, it was not possible to estimate the change in emissions of each individual HAP.

Monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we are providing a qualitative discussion of the health effects associated with HAP emitted from sources subject to control under the proposed NSPS OOOOb and EG OOOOc. The EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional aspects of HAP-related risk from the oil and natural gas sector, including the distribution of that risk. This is discussed further in the context of environment justice in Section 4.2.4.

3.6.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice (U.S EPA, 2003a; IARC 1982; Irons, 1992). The EPA states that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen, and the U.S. Department of Health and Human Services has characterized benzene as a known human carcinogen (IARC, 1987; NTP,

[50] The projected emissions reductions from the proposed NSPS and EG, including projections of HAP reductions, are based upon the unit-level model plant analysis supporting this rulemaking multiplied by counts of units that are potentially affected by this proposal. The model plants and counts are built from a different basis than the oil and natural gas sector emissions estimated in the NEI. Comparisons between the projected emissions reductions under this proposal and the NEI should be made with caution.

2004). Several adverse noncancer health effects have been associated with chronic inhalation of benzene in humans including arrested development of blood cells, anemia, leukopenia, thrombocytopenia, and aplastic anemia. Respiratory effects have been reported in humans following acute exposure to benzene vapors, such as nasal irritation, mucous membrane irritation, dyspnea, and sore throat (ATSDR, 2007a).

3.6.2 Formaldehyde

In 1989, the EPA classified formaldehyde as a probable human carcinogen based on limited evidence of cancer in humans and sufficient evidence in animals (U.S. EPA, 1991b). Later the IARC (2006, 2012) classified formaldehyde as a human carcinogen based upon sufficient human evidence of nasopharyngeal cancer and strong evidence for leukemia. Similarly, in 2016, the National Toxicology Program (NTP) classified formaldehyde as known to be a human carcinogen based on sufficient evidence of cancer from studies in humans supporting data on mechanisms of carcinogenesis (NTP, 2016). Formaldehyde inhalation exposure causes a range of noncancer health effects including irritation of the nose, eyes, and throat in humans and animals. Repeated exposures cause respiratory tract irritation, chronic bronchitis and nasal epithelial lesions such as metaplasia and loss of cilia in humans. Airway inflammation, including eosinophil infiltration, has been observed in animals exposed to formaldehyde. In children, there is evidence that formaldehyde may increase the risk of asthma and chronic bronchitis (ATSDR, 1999; WHO, 2002).

3.6.3 Toluene[51]

Under the 2005 Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005a), there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and

[51] All health effects language for this section came from: U.S. EPA (2005b).

narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

3.6.4 Carbonyl Sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate the eyes and skin in humans.[52] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under the EPA's IRIS program for evidence of human carcinogenic potential (U.S. EPA, 1991a).

3.6.5 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene

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[52] Hazardous Substances Data Bank (HSDB), online database. US National Library of Medicine, Toxicology Data Network, available online at https://pubchem.ncbi.nlm.nih.gov/. Carbonyl sulfide health effects summary available at https://pubchem.ncbi.nlm.nih.gov/compound/10039#section=Safety-and-Hazards. Accessed April 26, 2020.

in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral cavities in male and female rats exposed to ethylbenzene via the oral route (Maltoni, 1985; Maltoni, 1997). The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP, 1999). The NTP (1999) carried out a chronic inhalation bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

3.6.6 Mixed Xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects (U.S. EPA, 2003b). Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys (ATSDR, 2007b). Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination (ATSDR, 2007b). The EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

3.6.7 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes, and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005a), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.

3.6.8 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by this rule, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in the EPA's IRIS database.[53]

3.7 Total Benefits

Table 3-7 presents the PV and EAV of the projected climate benefits across the four regulatory options for the proposed NSPS OOOOb and EG OOOOc examined in this RIA. These values reflect an analytical time horizon of 2023 to 2035, are discounted to 2021, and presented in 2019 dollars. Multiple benefits estimates are presented reflecting alternative discount rates. The table includes consideration of the non-monetized benefits associated with the emissions reductions projected under this proposal. Table 3-8 and Table 3-9 present the same information for the proposed NSPS OOOOb and EG OOOOc separately.

[53] The U.S. EPA Integrated Risk Information System (IRIS) database is available at https://www.epa.gov/iris. Accessed April 26, 2020.

Table 3-7 Comparison of PV and EAV of the Projected Benefits for the Proposed NSPS OOOOb and EG OOOOc across Regulatory Options, 2023–2035 (millions of 2019$)

Year	5% Average	3% Average	2.50% Average	3% 95th Percentile
Climate Benefits (PV)[a]				
Less Stringent	$14,000	$35,000	$47,000	$94,000
Co-proposal	$22,000	$53,000	$71,000	$140,000
Primary Proposal	$22,000	$55,000	$74,000	$150,000
More Stringent	$24,000	$59,000	$79,000	$160,000
Climate Benefits (EAV)[a]				
Less Stringent	$1,500	$3,300	$4,300	$8,800
Co-proposal	$2,300	$5,000	$6,500	$13,000
Primary Proposal	$2,400	$5,200	$6,800	$14,000
More Stringent	$2,500	$5,600	$7,200	$15,000
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent	26,000,000			
Co-Proposal	39,000,000			
Primary Proposal	41,000,000			
More Stringent	43,000,000			
$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons):				
Less Stringent	8,000,000			
Co-Proposal	12,000,000			
Primary Proposal	12,000,000			
More Stringent	13,000,000			
HAP benefits from reducing HAP emissions by (in short tons):				
Less Stringent	330,000			
Co-Proposal	460,000			
Primary Proposal	480,000			
More Stringent	510,000			
Visibility benefits				
Reduced vegetation effects				

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 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. The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 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.

Table 3-8 Comparison of PV and EAV of the Projected Benefits for the Proposed NSPS OOOOb across Regulatory Options, 2023-2035 (millions of 2019$)

Year	5% Average	3% Average	2.50% Average	3% 95th Percentile
Climate Benefits (PV)[a]				
Less Stringent	$580	$1,400	$1,900	$3,800
Co-proposal	$3,200	$7,900	$11,000	$21,000
Primary Proposal	$3,300	$8,300	$11,000	$22,000
More Stringent	$3,600	$8,800	$12,000	$23,000
Climate Benefits (EAV)[a]				
Less Stringent	$62	$140	$180	$360
Co-proposal	$340	$740	$970	$2,000
Primary Proposal	$350	$780	$1,000	$2,100
More Stringent	$380	$830	$1,100	$2,200
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent		1,100,000		
Co-Proposal		5,800,000		
Primary Proposal		6,100,000		
More Stringent		6,500,000		
$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons):				
Less Stringent		420,000		
Co-Proposal		1,700,000		
Primary Proposal		1,800,000		
More Stringent		1,900,000		
HAP benefits from reducing HAP emissions by (in short tons):				
Less Stringent		16,000		
Co-Proposal		64,000		
Primary Proposal		67,000		
More Stringent		71,000		
Visibility benefits				
Reduced vegetation effects				

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 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. The IWG emphasized the importance and value of considering the benefits calculated using all four 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.

Table 3-9 Comparison of PV and EAV of the Projected Benefits for the Proposed EG OOOOc Across Regulatory Options, 2023-2035 (millions of 2019$)

Year	5% Average	3% Average	2.50% Average	3% 95th Percentile
Climate Benefits (PV)[a]				
Less Stringent	$14,000	$34,000	$45,000	$90,000
Co-proposal	$18,000	$45,000	$61,000	$120,000
Primary Proposal	$19,000	$47,000	$63,000	$130,000
More Stringent	$20,000	$50,000	$67,000	$130,000
Climate Benefits (EAV)[a]				
Less Stringent	$1,500	$3,200	$4,100	$8,500
Co-proposal	$2,000	$4,300	$5,500	$11,000
Primary Proposal	$2,000	$4,400	$5,800	$12,000
More Stringent	$2,200	$4,700	$6,100	$13,000
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent		25,000,000		
Co-Proposal		33,000,000		
Primary Proposal		35,000,000		
More Stringent		37,000,000		
$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons):				
Less Stringent		7,600,000		
Co-Proposal		9,900,000		
Primary Proposal		10,000,000		
More Stringent		11,000,000		
HAP benefits from reducing HAP emissions by (in short tons):				
Less Stringent		310,000		
Co-Proposal		400,000		
Primary Proposal		410,000		
More Stringent		440,000		
Visibility benefits				
Reduced vegetation effects				

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 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. The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 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.

4 ECONOMIC IMPACT AND DISTRIBUTIONAL ANALYSIS

The proposed NSPS OOOOb and EG OOOOc constitute an economically significant action. As discussed in previous section, the emissions reductions projected under the rule are likely to produce substantial climate benefits, peaking at $2.0 to $11 billion in 2035, as well as non-monetized benefits from large reductions in VOC and HAP emissions. At the same time, the proposed NSPS OOOOb and EG OOOOc is projected to result in substantial environmental control expenditures by the oil and natural gas industry to comply with the rule, reaching a maximum of $1.4 billion in 2026.

While the national level impacts demonstrate the proposal is likely to lead to significant benefits and costs, the benefit-cost analysis does not speak directly to potential economic and distributional impacts of the proposed rule, which may be important consequences of the action. This section includes four sets of economic impact and distributional analyses for this proposal directed toward complementing the benefit-cost analysis and includes an analysis of potential national-level impacts on oil and natural gas markets, a series of environmental justice analyses, an Initial Regulatory Flexibility Analysis that includes an analysis of projected compliance costs on small entities, and employment impacts.

4.1 Oil and Natural Gas Market Impact Analysis

In addition to the engineering cost analysis that produces the compliance cost and emissions reduction projections that inform the net benefits analysis, the EPA developed a pair of single-market, static partial-equilibrium analyses of national crude oil and natural gas markets. The market impact analyses are intended to provide readers some information on the economic impacts of the proposed NSPS OOOOb and EG OOOOc and to inform the EPA's response to EO 13211 "Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use." The partial equilibrium market impact estimates, however, do not inform the projected engineering costs and emissions reductions used in the comparison of benefits and costs. Additionally, the market impact analysis focuses on impacts of the primary proposed NSPS OOOOb and EG OOOOc option. As the regulatory costs of the co-proposed option are lower than the primary proposed option, market impact estimates would be smaller for the co-proposed option.

Our partial equilibrium analyses treat crude oil markets and natural gas markets separately. We implement a pair of single-market analyses instead of a coupled market or general equilibrium approach to provide broad insights into potential national-level market impacts while providing analytical transparency.

The oil market model assumes a single, aggregate U.S supplier, a single, aggregate world consumer, and a residual world supply. We assume the U.S. supply response to a percentage change in costs has the same effect as a percentage change in price. We do not try to model the residual world supply precisely. Instead, we model two extreme cases — perfectly inelastic residual world supply and perfectly elastic residual world supply. These cases bound the residual world supply response.

The natural gas market model assumes a single, aggregate U.S. supplier, a single, aggregate U.S. consumer, and no international trade. We assume the U.S. supply response to a percentage change in costs has the same effect as a percentage change in price. Existing natural gas markets are segmented in the short-term by transmission constraints, but prices are cointegrated across the United States (Siliverstovs et al. 2005). Infrastructure, including new infrastructure in the long term, joins disparate markets. The assumption of a single natural gas market is a long-term modeling assumption.

In each market, we first use a supply elasticity to solve for the supply change that results from the imposition of regulatory costs. Given the change in supply, we then use a demand elasticity to solve for the change in price that balances supply and demand. We use projected crude oil and natural gas prices and production for a select set of years of analysis to operationalize the model. In the sections that follow, we discuss the data and parameters used to implement the models, present results of each analysis, and conclude with a discussion of caveats and limitations of the analyses.

4.1.1 Crude Oil Market Model

The crude oil market model is a constant elasticity model that assumes a competitive U.S. market with a rest of world residual oil supply that is either perfectly inelastic or perfectly elastic. To find the changes in crude oil production and prices under the proposed NSPS OOOOb and EG

OOOOc, we first solve for the change in production using a supply elasticity and the regulatory cost. The year t change in U.S. oil production $\Delta Q_{O,t}^{US}$ is estimated using Eq. 4-1:

$$\Delta Q_{O,t}^{US} = \frac{C_{O,t}}{Q_{O,t}^{US} * P_{O,t}} * \varepsilon_{O,S} * Q_{O,t}^{US} \qquad \text{Eq. 4-1}$$

where $C_{O,t}$ is the projected regulatory cost impacting oil-producing sources in year *t*, $Q_{O,t}^{US}$ is the baseline U.S. crude oil production in year *t*, $P_{O,t}$ is the baseline crude oil price, and $\varepsilon_{O,S}$ is the supply elasticity of crude oil. The term $\frac{C_{O,t}}{Q_{O,t}^{US} * P_{O,t}}$ describes the cost change as a fraction of revenue, akin to a percentage change in price. A key modeling assumption here is that, in addition to a constant elasticity, a fractional change in revenue due to a cost change is equivalent to a fractional change in output price. The term then $\frac{C_{O,t}}{Q_{O,t}^{US} * P_{O,t}} * \varepsilon_{O,S}$ describes the fractional change in production.

For the model assuming perfectly inelastic rest-of-world production, we use the change in supply solved in Eq. 4-1 the find the change in crude oil prices using Eq. 4-2:

$$\Delta P_{O,t} = \frac{\Delta Q_{O,t}^{US}}{Q_{O,t}^{World}} * \frac{1}{\varepsilon_{O,D}} * P_{O,t} \qquad \text{Eq. 4-2}$$

where $Q_{O,t}^{World}$ is global production of crude oil and $\varepsilon_{O,D}$ is the world demand elasticity for crude oil.

Price does not change in the alternative model; it assumes perfectly elastic rest-of-world production, so $\Delta P_{O,t} = 0$.

4.1.2 Natural Gas Market Model

We model U.S. natural gas supply and demand as a closed market. For the natural gas market, we first find the change in quantity produced $\Delta Q_{G,t}$ using Eq 4.-3:

$$\Delta Q_{G,t} = \frac{C_{G,t}}{Q_{G,t} * P_{G,t}} * \varepsilon_{G,S} * Q_{G,t} \qquad \text{Eq. 4-3}$$

where $C_{G,t}$ is the projected regulatory cost impacting all segments of the natural gas industry in year *t*, $Q_{G,t}$ is the baseline U.S. production forecast, $P_{G,t}$ is the natural gas price forecast, and $\varepsilon_{G,S}$ is the supply elasticity for natural gas.

We then use the change in quantity solved in Eq. 4.3 to solve for the natural gas price change $\Delta P_{G,t}$ using Eq. 4-4:

$$\Delta P_{G,t} = \frac{\Delta Q_{G,t}}{Q_{G,t}} * \frac{1}{\varepsilon_{G,D}} * P_{G,t} \qquad \text{Eq. 4-4}$$

4.1.3 Assumptions, Data, and Parameters Used in the Oil and Natural Gas Market Models

This section presents the basics assumptions applied in this analysis. The section also presents the data and parameters used to operationalize the model, including our choice of years of analysis, elasticity estimates, and production and price data.

4.1.3.1 Years of Analysis

We estimate the price and quantity impacts of the proposed NSPS OOOOb and EG OOOOc on crude oil and natural gas markets for a subset of years within the time horizon analyzed in this RIA. We analyze 2023 and 2025 as these years represent the first and last year the requirements in the proposed NSPS OOOOb will be in effect for the purposes of the RIA before the requirement of the proposed EG OOOOc are assumed to go into effect. We then analyze market impacts in 2026, 2030, and 2035 to examine the effects of the proposed EG OOOOc in addition to the cumulative impacts of the proposed NSPS OOOOb. The year 2026 is the year of analysis with the highest regulatory costs and, as such, will represent the year with the largest market impacts based upon the partial equilibrium market models used here. We analyze 2030 and 2035 in order to project impacts in later years of the time horizon, as the projected regulatory costs decline.

4.1.3.2 Elasticity Choices

The elasticity estimates used in the analysis are based on estimates from the published economics literature (Table 4-1). Natural gas demand elasticity is calculated as the sector-level consumption-weighted average of demand elasticities from Hausman and Kellogg (2015). The consumption proportions used to weight the elasticities are derived from 2019 levels of natural consumption by the residential, commercial, industrial, and electric power sectors, as reported in EIA.

Table 4-1 Parameters Used in Market Analysis

Parameter	Symbol	Value	Source
Oil supply elasticity	$\varepsilon_{O,S}$	1.2	Newell, R. G., & B. C. Prest. 2019. The unconventional oil supply boom: Aggregate price response from microdata. *The Energy Journal* 40(3).
Oil demand elasticity	$\varepsilon_{O,D}$	-0.37	Coglianese, J., L. W. Davis, L. Kilian, & J. H. Stock. 2017. Anticipation, tax avoidance, and the price elasticity of gasoline demand. *Journal of Applied Econometrics* 32(1):1-15.
Natural gas supply elasticity	$\varepsilon_{G,S}$	0.9	Newell, R. G., B. C. Prest, & A. B. Vissing. 2019. Trophy hunting versus manufacturing energy: The price responsiveness of shale gas." *Journal of the Association of Environmental and Resource Economists* 6(2): 391-431.
Natural gas demand elasticity	$\varepsilon_{G,D}$	-0.43	Sector-level consumption-weighted average of demand elasticities from Hausman, C. & R. Kellogg. 2015. Welfare and Distributional Implications of Shale Gas. *Brookings Papers on Economic Activity*:71-125.

4.1.3.3 Production and Price Data

Baseline U.S. crude oil production, dry gas production, West Texas Intermediate (WTI) crude oil prices, and Henry Hub natural gas prices are drawn from AEO2021. Prices are deflated from 2020 dollars to 2019 dollars using the GDP-Implicit Price Deflator. As the proposed NSPS OOOOb and EG OOOOc apply to onshore production but not offshore production, only onshore U.S. crude oil production is analyzed. Dry natural gas production is the sum of onshore production from the lower 48 states and all production from Alaska. Baseline world crude oil production is from the Energy Information Administration's 2020 International Energy Outlook. Table 4-2 presents the baseline crude oil and natural gas production and prices used in the market impacts analysis.

Table 4-2 Baseline Crude Oil and Natural Gas Production and Prices Used in Market Analysis

Data	Resource	Unit	Year				
			2023	2025	2026	2030	2035
Baseline Production[a]							
	U.S. Crude Oil Production	million bbl/day	9.6	9.6	10.3	11.5	11.4
	World Oil Production	million bbl/day	97.1	97.7	98.0	99.5	101.8
	U.S. Onshore Production	tcf/year	32.7	31.8	33.2	36.1	37.0
Baseline Prices[a]							
	Crude Oil	2019$/bbl	52.5	58.6	60.6	69.7	75.9
	Natural Gas	2019$/MMbtu	2.96	2.85	2.95	3.30	3.49
	Natural Gas	2019$/Mcf	3.07	2.95	3.06	3.43	3.62

[a] Baseline U.S. crude oil and natural gas production and prices drawn from AEO2021. Baseline world oil production drawn from EIA's International Energy Outlook.

4.1.3.4 Regulatory Cost Impacts

As discussed earlier, we assume the projected regulatory costs associated with the proposed NSPS OOOOb and EG OOOOc produce a fractional change in output price. We distribute the projected regulatory costs to crude oil markets and natural gas markets according to whether the emissions sources incurring the regulatory costs are more likely to be producing crude oil or producing, processing, or transporting natural gas. To begin, all projected regulatory costs for natural gas processing, storage, and transmission sources are assumed to impact the natural gas market. Within the production segment, projected regulatory costs for natural gas-related model plants are directed to natural gas markets and costs for oil-related model plants are assigned to crude oil markets. For example, projected regulatory costs associated with fugitive emissions monitoring at natural gas well sites are directed to the natural gas market, and projected regulatory costs at oil well sites are directed to crude oil markets.

For this analysis, we use the projected regulatory costs with capital costs annualized using a 7 percent interest rate. We also use the net regulatory costs, which include projected revenues from natural gas recovery from emissions abatement activities. Table 4-3 presents the results of decomposing the projected regulatory costs into crude oil and natural gas shares.

Table 4-3 Projected Regulatory Costs for the Primary Proposed NSPS OOOOb and EG OOOOc Option Applied in the Market Analysis (millions 2019$)

	Year				
Resource	**2023**	**2025**	**2026**	**2030**	**2035**
Crude Oil	-2.8	-4.3	615.4	471.7	344.5
Natural Gas	7.6	15.7	847.6	677.5	542.3

4.1.4 Results

The results of incorporating the projected regulatory costs into the crude oil market model are presented in Table 4-4. In the analyzed years of 2023 and 2025, when only requirements of the proposed NSPS OOOOb are in effect, the proposal is projected to lead to an increase in crude oil production due to reduced regulatory costs relative to baseline. Once the requirements of the proposed EG OOOOc are assumed to go into effect in 2026, we project a reduction in crude oil production. At its peak, the reduction is about 12.19 million barrels in 2026 or about 0.33 percent of crude oil production.

Table 4-4 Estimated Crude Oil Production and Prices Changes under the Primary Proposed NSPS OOOOb and EG OOOOc Option

		Year				
Variable	**Change**	**2023**	**2025**	**2026**	**2030**	**2035**
U.S. Production	million bbls/year	0.06	0.09	-12.19	-8.12	-5.45
	%	0.00%	0.00%	-0.33%	-0.19%	-0.13%
U.S. Prices						
Assuming Perfectly Inelastic Rest of World Supply	$/bbl	0.00	0.00	0.06	0.04	0.03
	%	0.00%	0.00%	0.09%	0.06%	0.04%
Assuming Perfectly Elastic Rest of World Supply	$/bbl	0	0	0	0	0
	%	0.00%	0.00%	0.00%	0.00%	0.00%

We describe two models of world oil markets that bound the market price responses. Table 4-4 describes results. Assuming perfectly inelastic world oil markets represents an upper bound on the crude oil price change. The maximum projected oil price change in modeled years is $0.06 per barrel in 2026, an increase of less than one tenth of one percent. The alternative model is that world oil markets are perfectly elastic and maintain a fixed oil price. In that case the price change would be zero. Table 4-5 presents results of entering the projected regulatory costs in the natural gas market model. We project a maximum natural gas price increase of about $0.05 per mcf and a maximum production reduction of about 249.4 million Mcf per year, changes of about 1.76 percent and 0.75 percent respectively.

Table 4-5 Estimated Natural Gas Production and Prices Changes under the Primary Proposed NSPS OOOOb and EG OOOOc Option

		Year				
Variable	**Change**	**2023**	**2025**	**2026**	**2030**	**2035**
U.S. Onshore Production	million Mcf/year	-2.2	-4.8	-249.4	-177.9	-134.8
	%	-0.01%	-0.01%	-0.75%	-0.49%	-0.36%
U.S. Prices						
	2019$/Mcf	0.00	0.00	0.05	0.04	0.03
	%	0.02%	0.04%	1.76%	1.15%	0.85%

We use the results in Table 4-4 and Table 4-5 to evaluate whether the proposed NSPS OOOOb and EG OOOOc is likely to have a significant effect on the supply, distribution, or use of energy as defined by EO 13211. To make this determination, we compare the projected change in crude oil and natural gas production to guidance articulated in a January 13, 2021 OMB memorandum “Furthering Compliance with Executive Order 13211, Titled "Actions Concerning Regulations

That Significantly Affect Energy Supply, Distribution, or Use".”[54] With respect to crude oil production, the guidance indicates that a regulatory action produces a significant adverse effect if it is expected to produce reductions in crude oil supply, in excess of 20 million barrels per year. With respect to natural gas production, the guidance indicates that a regulatory action produces a significant adverse affect if it reduces natural gas production in in excess of 40 million mcf per year.[55] The maximum projected decrease in crude oil production does not exceed the indicator in the guidance for adverse effects. However, the maximum projected decrease in natural gas production exceeds the benchmark for adverse effects, so this analysis indicates the proposed NSPS OOOOb and EG OOOOc constitutes a significant energy action.

4.1.5 Caveats and Limitations of the Market Analysis

The oil and natural gas market impact analysis presented in this section is subject to several caveats and limitations, which we discuss here. As with any modeling exercise, the market impact analysis presented here depends crucially on uncertain input parameters. These parameters include the cost to firms of compliance, the amount of natural gas that would be recovered and sold as a result of emissions abatement requirements compliance, baseline projections, and elasticity estimates. We note the change in price is particularly sensitive to the demand elasticity.

This analysis considers two residual rest-of-world supply models — perfectly elastic and perfectly inelastic. The structure of international oil markets (both supply and demand) have shifted historically and may shift in the future. While these models bound the minimum and maximum price changes, there is uncertainty within those bounds. One common modelling assumption is that world oil prices are fixed relative to policy changes. This would imply perfectly elastic residual rest-of-world supply.

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[54] See https://www.whitehouse.gov/wp-content/uploads/2021/01/M-21-12.pdf.

[55] The 2021 EO13211 guidance memo states that the natural gas production decrease that indicates the regulatory action is a significant energy action is 40 mcf per year. Because this is a relatively small amount of natural gas and previous guidance from 2001 indicated a threshold of 25 million Mcf, we assume the 2021 memo was intended to establish 40 million Mcf as the indicator of an adverse energy effect. See https://www.whitehouse.gov/wp-content/uploads/2017/11/2001-M-01-27-Guidance-for-Implementing-E.O.-13211.pdf.

This analysis uses a single-period model which is parameterized for different years, whereas dynamic effects are important in oil and natural gas markets. Production decisions relating to drilling and shutting-in wells affect future production, well decline curves, and intertemporal price arbitrage (the Hotelling Rule). Consideration of dynamic effects may shift numerical results. To the extent the proposed NSPS OOOOb and EG OOOOc may impact well drilling and shut-in decisions, the static analysis present here potentially overlooks important distributional consequences of the proposed regulation.

This analysis does not distinguish between different regions of the U.S. The cost of producing oil and natural gas varies over the U.S. Compliance costs may also vary. Reductions in oil and natural gas production would be larger in regions with higher production costs or higher compliance costs. This could result in different price changes in different regions of the country if oil is there are bottlenecks in oil or natural gas shipping infrastructure.

Oil and natural gas markets are linked on both the supply and demand sides. On the supply side, individual wells generally produce a mixture of oil and natural gas, and some of the same resources can be used to drill either oil-targeting wells or natural gas-targeting wells. On the demand side, oil and natural gas are substitutes in some markets. Consideration of these linkages may additionally shift numerical results.

4.2 Environmental Justice Analyses

For this proposed rulemaking, the EPA conducted limited environmental justice (EJ) analyses focused on a baseline distribution of emissions from oil and natural gas sources. EJ analyses described in this section evaluate only baseline scenarios; this enables us to characterize risks due to oil and natural gas emissions prior to implementation of the proposed rule. However, we lack key information that would be needed to characterize post-control risks under the proposed NSPS OOOOb and EG OOOOc or the regulatory alternatives analyzed in this RIA. Therefore, the extent to which this proposed rule will affect potential EJ concerns is not evaluated explicitly due to data limitations that prevent us from analyzing spatially differentiated outcomes.

As policy-specific air quality scenarios corresponding to future years analyzed in this proposal (e.g., 2023 to 2035) were not evaluated, it is unknown how the proposed rule will impact potential EJ concerns that may relate to the distribution of oil and natural gas emissions, as well as those related to employment. Importantly, we note that this proposal may not impact all locations with oil and natural gas emissions equally, in part due to differences in existing state regulations in locations like Colorado and California, which have more stringent requirements. Additionally, these discussions and analyses are subject to various types of uncertainty related to input parameters and assumptions.

After discussing the rationale for including EJ considerations in rulemakings (Section 4.2.1), we present several potential vulnerabilities to climate-related stress qualitatively in Section 4.2.2. Quantitative EJ assessments include an analysis of ozone from oil and natural gas VOC emissions (Section 4.2.3), risk from oil and natural gas air toxic emissions (Section 4.2.4), oil and natural gas workers and communities (Section 4.2.5), and how households may be affected by potential energy market impacts (Section 4.2.6). Overall, there is some evidence that certain populations may be disproportionately impacted by oil and natural gas emissions, although data gaps remain.

4.2.1 Background

EO 12898 (59 FR 7629; February 16, 1994) and EO 14008 (86 FR 7619; January 27, 2021) establish federal executive policy on environmental justice. EO 12898's main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.[56] Meaningful involvement means that: (1) potentially affected populations have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health; (2) the public's contribution can influence the regulatory Agency's decision; (3) the concerns of all

[56] See, e.g., "Environmental Justice." *Epa.gov*, U.S. Environmental Protection Agency, 4 Mar. 2021, https://www.epa.gov/environmentaljustice.

participants involved will be considered in the decision-making process; and (4) the rule-writers and decision-makers seek out and facilitate the involvement of those potentially affected.[57]

The term "disproportionate impacts" refers to differences in impacts or risks that are extensive enough that they may merit Agency action. In general, the determination of whether a disproportionate impact exists is ultimately a policy judgment which, while informed by analysis, is the responsibility of the decision-maker. The terms "difference" or "differential" indicate an analytically discernible distinction in impacts or risks across population groups. It is the role of the analyst to assess and present differences in anticipated impacts across population groups of concern for both the baseline and proposed regulatory options, using the best available information (both quantitative and qualitative) to inform the decision-maker and the public.[58]

A regulatory action may involve potential environmental justice concerns if it could: (1) create new disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; (2) exacerbate existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; or (3) present opportunities to address existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples through the action under development.

EO 14008 calls on agencies to make achieving environmental justice part of their missions "by developing programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts." EO 14008 further declares a policy "to secure environmental justice and spur economic opportunity for disadvantaged communities that have been historically marginalized and overburdened by pollution and under-investment in housing, transportation, water and wastewater infrastructure, and health care." In addition, the Presidential Memorandum on Modernizing Regulatory Review

[57] The criteria for meaningful involvement are contained in EPA's May 2015 guidance document, "Guidance on Considering Environmental Justice During the Development of an Action." *Epa.gov*, U.S. Environmental Protection Agency, 17 Feb. 2017, www.epa.gov/environmentaljustice/guidance-considering-environmental-justice-during-development-action.

[58] The definitions and criteria for "disproportionate impacts," "difference," and "differential" are contained in EPA's June 2016 guidance document "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis." *Epa.gov*, U.S. Environmental Protection Agency, https://www.epa.gov/sites/production/files/2016-06/documents/ejtg_5_6_16_v5.1.pdf.

calls for procedures to "take into account the distributional consequences of regulations, including as part of a quantitative or qualitative analysis of the costs and benefits of regulations, to ensure that regulatory initiatives appropriately benefit, and do not inappropriately burden disadvantaged, vulnerable, or marginalized communities." the EPA also released its June 2016 "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis"[59] to provide recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time and resource constraints, and analytical challenges will vary by media and circumstance.

A reasonable starting point for assessing the need for a more detailed environmental justice analysis is to review the available evidence from the published literature and from community input on what factors may make population groups of concern more vulnerable to adverse effects (e.g., cumulative exposure from multiple stressors). It is also important to evaluate the data and methods available for conducting an environmental justice analysis. EJ analyses can be grouped into two types, both of which are informative, but not always feasible for a given rulemaking:

1. Baseline: Describes the current (pre-control) distribution of risk and exposures, identifying potential disparities.

2. Policy: Describes the distribution of risk and exposures after the control strategy has been applied (post-control), identifying how potential disparities change in response to the rulemaking.

EPA's 2016 Technical Guidance does not prescribe or recommend a specific approach or methodology for conducting an environmental justice analysis, though a key consideration is consistency with the assumptions underlying other parts of the regulatory analysis when evaluating the baseline and regulatory options.

4.2.2 Climate Impacts

In 2009, under the *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act* ("Endangerment Finding"), the Administrator considered how climate change threatens the health and welfare of the U.S. population. As part of that consideration, she also considered risks to minority and low-income individuals and

[59] See https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.

communities, finding that certain parts of the U.S. population may be especially vulnerable based on their characteristics or circumstances. These groups include economically and socially disadvantaged communities; including those that have been historically marginalized or overburdened; individuals at vulnerable lifestages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; the disabled; those experiencing homelessness, mental illness, or substance abuse; and/or Indigenous or minority populations dependent on one or limited resources for subsistence due to factors including but not limited to geography, access, and mobility.

Scientific assessment reports produced over the past decade by the U.S. Global Change Research Program (USGCRP, 2016; USGCRP, 2018), the Intergovernmental Panel on Climate Change (IPCC) (Oppenheimer et al., 2014; Porter et al., 2014; Smith et al., 2014; IPCC, 2018), and the National Academies of Science, Engineering, and Medicine add more evidence that the impacts of climate change raise potential environmental justice concerns (NRC, 2011; National Academies, 2017). These reports conclude that less-affluent, traditionally marginalized, or predominantly non-White communities can be especially vulnerable to climate change impacts because they tend to have limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location (e.g., African-American, Black, and Hispanic/Latino communities; Native Americans, particularly those living on Tribal lands and Alaska Natives), may be uniquely vulnerable to climate change health impacts in the United States, as discussed below. In particular, the 2016 scientific assessment on the *Impacts of Climate Change on Human Health* found with high confidence that vulnerabilities are place- and time-specific, lifestages and ages are linked to immediate and future health impacts, and social determinants of health are linked to greater extent and severity of climate change-related health impacts (USGCRP, 2016).

Per the Fourth National Climate Assessment, “Climate change affects human health by altering exposures to heat waves, floods, droughts, and other extreme events; vector-, food- and waterborne infectious diseases; changes in the quality and safety of air, food, and water; and stresses to mental health and well-being” (Ebi et al., 2018). Many health conditions such as cardiopulmonary or respiratory illness and other health impacts are associated with and exacerbated by an increase in greenhouse gases and climate change outcomes, which is problematic as these diseases occur at higher rates within vulnerable communities. Importantly, negative public health outcomes include those that are physical in nature, as well as mental, emotional, social, and economic.

The scientific assessment literature, including the aforementioned reports, demonstrates that there are myriad ways in which these populations may be affected at the individual and community levels.Outdoor workers, such as construction or utility workers and agricultural laborers, who are frequently part of already at-risk groups, are exposed to poor air quality and extreme temperatures without relief. Furthermore, individuals within EJ populations of concern face greater housing and clean water insecurity and bear disproportionate economic impacts and health burdens associated with climate change effects. They have less or limited access to healthcare and affordable, adequate health or homeowner insurance. The urban heat island effect can add additional stress to vulnerable populations in densely populated cities who do not have access to air conditioning. Finally, resiliency and adaptation are more difficult for economically disadvantaged communities: They tend to have less liquidity, individually and collectively, to move or to make the types of infrastructure or policy changes necessary to limit or reduce the hazards they face. They frequently face systemic, institutional challenges that limit their power to advocate for and receive resources that would otherwise aid in resiliency and hazard reduction and mitigation.

The assessment literature cited in EPA's 2009 and 2016 Endangerment Findings, as well as *Impacts of Climate Change on Human Health,* also concluded that certain populations and people in particular life stages, including children, are most vulnerable to climate-related health effects. The assessment literature produced from 2016 to the present strengthens these conclusions by providing more detailed findings regarding related vulnerabilities and the projected impacts youth may experience. These assessments — including the Fourth National Climate Assessment (2018) and *The Impacts of Climate Change on Human Health in the United States* (2016) — describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to allergens, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More generally, these reports note that extreme weather and flooding can cause or exacerbate poor health outcomes by affecting mental health because of stress; contributing to or worsening existing conditions, again due to stress or also as a consequence of exposures to water and air pollutants; or by impacting hospital and emergency services operations (Ebi et al., 2018). Further, in urban areas in particular, flooding can have significant economic consequences due to effects on infrastructure, pollutant exposures, and drowning dangers. The ability to withstand and recover from flooding is dependent in part on the social vulnerability of the affected population and individuals experiencing an event (National Academies, 2019).

The Impacts of Climate Change on Human Health also found that some communities of color, low-income groups, people with limited English proficiency, and certain immigrant groups (especially those who are undocumented) live with many of the factors that contribute to their vulnerability to the health impacts of climate change (USGCRP, 2016). While difficult to isolate from related socioeconomic factors, race appears to be an important factor in vulnerability to climate-related stress, with elevated risks for mortality from high temperatures reported for Black or African American individuals compared to White individuals after controlling for factors such as air conditioning use. Moreover, people of color are disproportionately exposed to air pollution based on where they live, and disproportionately vulnerable due to higher baseline prevalence of underlying diseases such as asthma, so climate exacerbations of air pollution are expected to have disproportionate effects on these communities.

The recent EPA report on climate change and social vulnerability examined four socially vulnerable groups (individuals who are low income, minority, without high school diplomas, and/or 65 years and older) and their exposure to several different climate impacts (air quality, coastal flooding, extreme temperatures, and inland flooding) (U.S. EPA, 2021c). This report found that Black and African-American individuals were 40 percent more likely to currently live in areas with the highest projected increases in mortality rates due to climate-driven changes in extreme temperatures, and 34 percent more likely to live in areas with the highest projected increases in childhood asthma diagnoses due to climate-driven changes in particulate air pollution. The report found that Hispanic and Latino individuals are 43 percent more likely to live in areas with the highest projected labor hour losses in weather-exposed industries due to climate-driven warming, and 50 percent more likely to live in coastal areas with the highest projected increases in traffic delays due to increases in high-tide flooding. The report found that American Indian and Alaska Native individuals are 48 percent more likely to live in areas where the highest percentage of land is projected to be inundated due to sea level rise, and 37 percent more likely to live in areas with high projected labor hour losses. Asian individuals were found to be 23 percent more likely to live in coastal areas with projected increases in traffic delays from high-tide flooding. Those with low income or no high school diploma are about 25 percent more likely to live in areas with high projected losses of labor hours, and 15 percent more likely to live in areas with the highest projected increases in asthma due to climate-driven increases in particulate air pollution, and in areas with high projected inundation due to sea level rise.

Indigenous communities possess unique vulnerabilities to climate change, particularly those communities impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Indigenous communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The IPCC indicates that losses of customs and historical knowledge may cause communities to be less resilient or adaptable (Porter et al., 2014). The Fourth National Climate Assessment (2018) noted that while Indigenous peoples are diverse and will be impacted by the climate changes universal to all Americans, there are several ways in which climate change uniquely threatens Indigenous peoples' livelihoods and economies (Jantarasami et al., 2018). In addition, there can be institutional barriers to their management of water, land, and other natural resources that could impede adaptive measures.

For example, Indigenous agriculture in the Southwest is already being adversely affected by changing patterns of flooding, drought, dust storms, and rising temperatures leading to increased soil erosion, irrigation water demand, and decreased crop quality and herd sizes. The Confederated Tribes of the Umatilla Indian Reservation in the Northwest have identified climate risks to salmon, elk, deer, roots, and huckleberry habitat. Housing and sanitary water supply infrastructure are vulnerable to disruption from extreme precipitation events. Confounding general Native American response to natural hazards are limitations imposed by policies such as the Dawes Act of 1887 and the Indian Reorganization Act of 1934, which ultimately restrict Indigenous peoples' autonomy regarding land-management decisions through Federal trusteeship of certain Tribal lands and mandated Federal oversight of management decisions.

Additionally, NCA4 noted that Indigenous peoples are subjected to institutional racism effects, such as poor infrastructure, diminished access to quality healthcare, and greater risk of exposure to pollutants. Consequently, Native Americans often have disproportionately higher rates of asthma, cardiovascular disease, Alzheimer's, diabetes, and obesity, which can all contribute to increased vulnerability to climate-driven extreme heat and air pollution events. These factors also may be exacerbated by stressful situations, such as extreme weather events, wildfires, and other circumstances.

NCA4 and IPCC AR5 also highlighted several impacts specific to Alaskan Indigenous Peoples (Porter et al., 2014). Coastal erosion and permafrost thaw will lead to more coastal erosion, rendering winter travel more risky and exacerbating damage to buildings, roads, and other infrastructure – these impacts on archaeological sites, structures, and objects that will lead to a loss of cultural heritage for Alaska's Indigenous people. In terms of food security, the NCA discussed reductions in suitable ice conditions for hunting, warmer temperatures impairing the use of traditional ice cellars for food storage, and declining shellfish populations due to warming and acidification. While the NCA also noted that climate change provided more opportunity to hunt from boats later in the fall season or earlier in the spring, the assessment found that the net impact was an overall decrease in food security.

4.2.3 Criteria Pollutant Impacts[60]

To evaluate the EJ implications of criteria pollution (CAP) emissions from the oil and natural gas sector, we focus in particular on ozone, noting that VOC emissions from the sector may

[60] The illustrative screening analysis of projected ozone-related health benefits from VOC reductions under the primary proposal (presented in Section 8.4) is subject to uncertainties in addition to those associated with the baseline ozone-related environmental justice analysis presented in this section. For example, the VOC emissions contributing to baseline concentrations of ozone in the environmental justice analysis are derived from the NEI, while the emissions reductions projected under the proposal for this RIA are based upon a mix of model plant

contribute to ozone formation across the U.S. Specifically, we analyzed a recent baseline (pre-control) air quality scenario comparing exposures to ozone formed from VOC emissions from the oil and natural gas sector across races/ethnicities, ages, and sexes. We focus mainly on exposure differences because these provide the clearest view into whether emissions from this sector may be unequally distributed among population subgroups of interest. However, actual population-level impacts from ozone exposure also depend on underlying risk factors (e.g., age) that vary across these population subgroups. The distribution of such risk factors can obscure differences in exposure and affect the risk (health impact) estimates. Therefore, risk across potential EJ populations is assessed in Appendix C, which clearly demonstrates how results are influenced by differences in the age distributions of White and non-White populations.[61]

4.2.3.1 Data Inputs

Input data for this CAP EJ analysis included potential population characteristics of concern (Section (a)), air quality scenarios (Section (b)), and health outcomes (Section (c)).

(a) Population Characteristics

A reasonable starting point for assessing the need for a more detailed EJ analysis is to review the available evidence from the published literature and from community input on what factors may make population groups of concern more vulnerable to adverse effects. The Health Effects Institute (HEI) provided a bibliography of peer-reviewed studies published since 2015 that evaluate populations that may be disproportionately impacted by the oil and natural gas industry.[62] However, there is considerable discordance among the study results. For example, studies differ with regards to geographic area, population of interest, and health outcome. To broadly assess potential EJ concerns, we evaluated disproportionate exposure and risk across racial and ethnic demographics, sexes, and ages as described in Table 4-1.

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information used in the rulemaking and activity factors as described in Section 2.2. Importantly, the illustrative screening analysis projects emissions reductions at a national-level while the NEI-based emissions informing the air quality modeling underpinning the environmental justice analysis are more spatially resolved.

[61] We note that sources identified as part of the oil and natural gas sector here may not include all sources covered by this proposed rule. In addition, some sources categorized as oil and natural gas sources in here may not be covered by this rule.

[62] Email to EPA staff from Janet McGovern of the Health Effects Institute on May 12th, 2021. Located at Docket ID No. EPA-HQ-OAR-2021-0317.

Table 4-6 Components of the Criteria Pollutant Environmental Justice Assessment

EJ Characteristics	Description
Race	White, Black, Asian, Native American
Ethnicity	Hispanic, Non-Hispanic
Age	0-17, 18-64, 65-99
Sex	Male, Female

(b) Air Quality Scenarios

Here we utilize modeled baseline conditions of ozone formed from oil and natural gas VOC emissions developed for the year 2017 (Figure 4-1) (U.S. EPA, 2021a). These air quality surfaces were developed using source apportionment (SA) modeling estimates of ozone concentrations attributable to certain precursors such as VOC from individual sectors, which can provide insight into the baseline (i.e., pre-rulemaking) scenario of a historical year (Appendix B, Section B.1.2).[63] Please note the scale, as concentrations of ozone formed from oil and natural gas VOC emissions represent a relatively small proportion of median annual MDA8 concentrations.[64] Higher concentrations of ozone formed from oil and natural gas VOC emissions tend to localize to areas of known oil and natural gas facility locations.

[63] Additional information on the SA modeling is available from U.S. EPA (2021a).
[64] Median annual MDA8 ozone concentration in 2015-2017 were 40 parts per billion (ppb); see Table 1-1 in U.S. EPA (2020a).

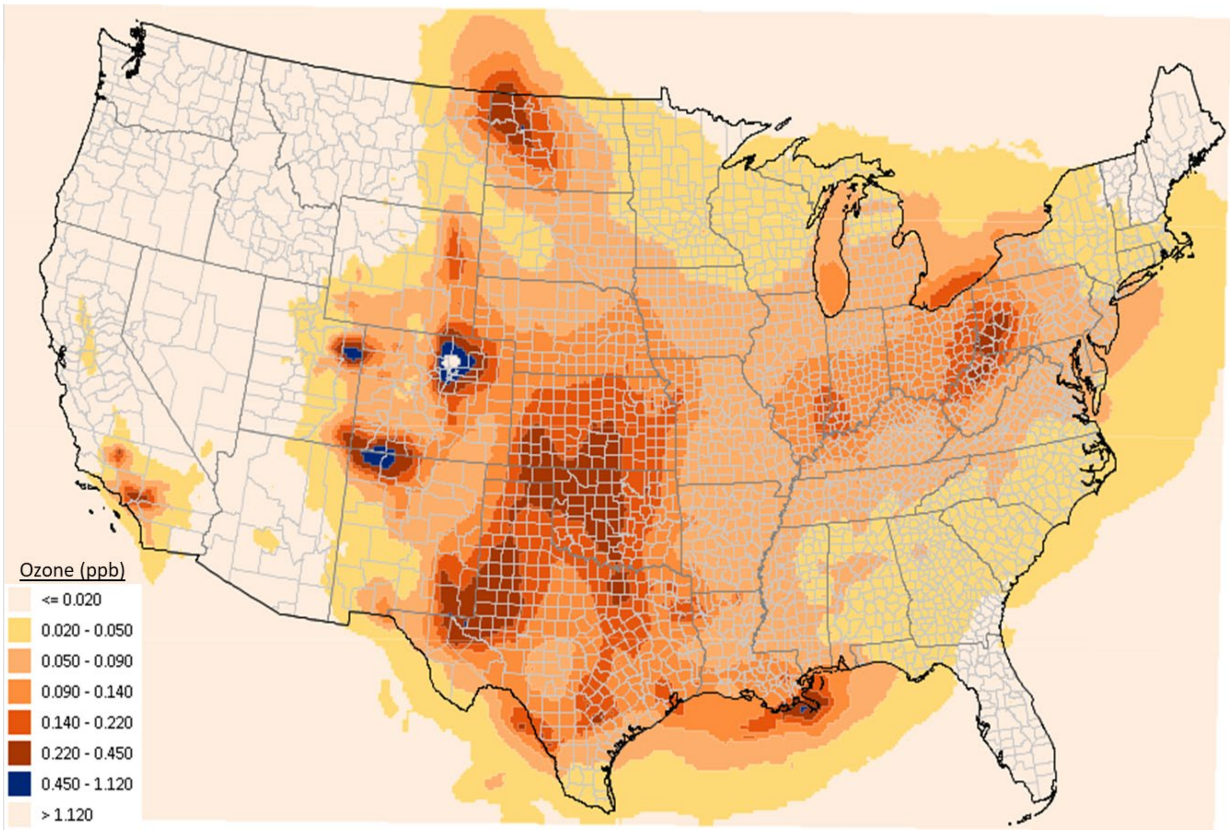

Figure 4-1 Map of Baseline Ozone Concentrations from Oil and Natural Gas VOC Emissions in 2017

(c) Health Outcomes

This CAP EJ assessment focuses on health endpoints causally linked to ozone exposure with the greatest public health significance. Mortality is arguably the most relevant health outcome and the 2020 Ozone ISA determined that there exists a “likely to be causal” relationship between long-term ozone exposure and respiratory outcomes, including respiratory mortality (U.S. EPA, 2020a). As such, we focused on evaluating any disproportionate impacts on ozone-related respiratory mortality in adults aged 30–99.

4.2.3.2 Results

Results of this CAP EJ analysis include the average (Section (a)) and distribution (Section (b)) of ozone exposures.

(a) Average Ozone Exposures

Average mean daily 8-hour maximum (MDA8) ozone concentrations from oil and natural gas VOC emissions between April and September of 2017 are shown in Figure 4-2. Exposures for the overall reference group, adults of all races/ethnicities and sexes aged 30–99, is shown in the top row, with population specific comparisons available below. For example, this baseline analysis shows that Native American populations on average may be exposed to a higher concentration of ozone from oil and natural gas VOC emissions than White populations, who in turn may on average be exposed to a higher concentration than the overall reference group. Similarly, the analysis suggests that Hispanic populations on average are exposed to a higher concentration of ozone from oil and natural gas VOC emissions than both non-Hispanic individuals and the overall reference group. The right column also provides information regarding the number of people within each demographic group. For example, there were less the 2 million Native Americans and nearly 30 million Hispanics in the contiguous U.S. in 2017.

African American or Black populations and Asian populations may on average be exposed to lower concentrations than White populations and the overall reference group. Regarding sex, females and males are estimated to be exposed to similar concentrations as compared to the reference group. Finally, when comparing average exposure across age ranges, ozone concentrations from oil and natural gas VOC emissions appears to decrease as age increases.

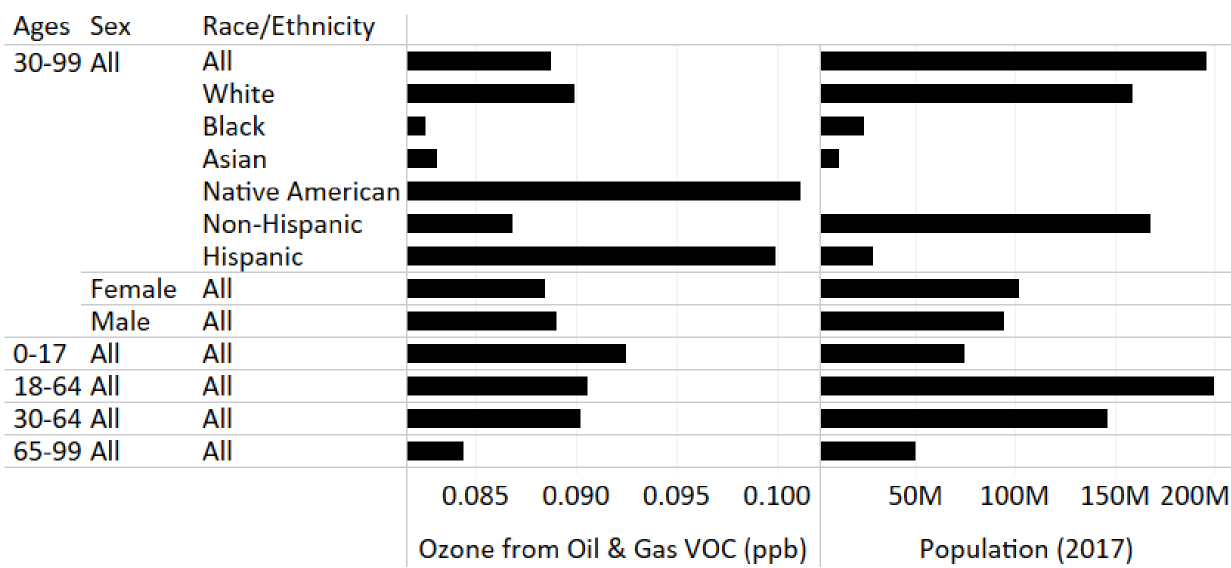

Figure 4-2 Average Ozone Concentrations from Oil and Natural Gas VOC Emissions by Population and Corresponding 2017 Population Counts

(b) Distribution of Ozone Exposures

While average exposure concentrations within demographic populations can convey some insight, distributional information, while more complex, can provide a more comprehensive understanding of the analytical results. As such, using the same baseline scenario described above, we provide the running sum percentage of each population plotted against the increasing ozone concentration from oil and natural gas VOC emissions in Figure 4-3 to permit the direct comparison of demographic populations with different absolute numbers. While the analysis indicates that exposures to ozone from oil and natural gas VOC emissions may be similar across all races/ethnicities in the lower 60 percent of each population, it suggests there are small differences in the 65–95 percent of populations exposed to higher ozone concentrations from oil and natural gas VOC emissions in some populations. Notably, a subset of Hispanics and Native American populations, shown in the dark and light orange lines, respectively, may experience slightly higher exposures to ozone from oil and natural gas VOC emissions than White and non-Hispanic populations.

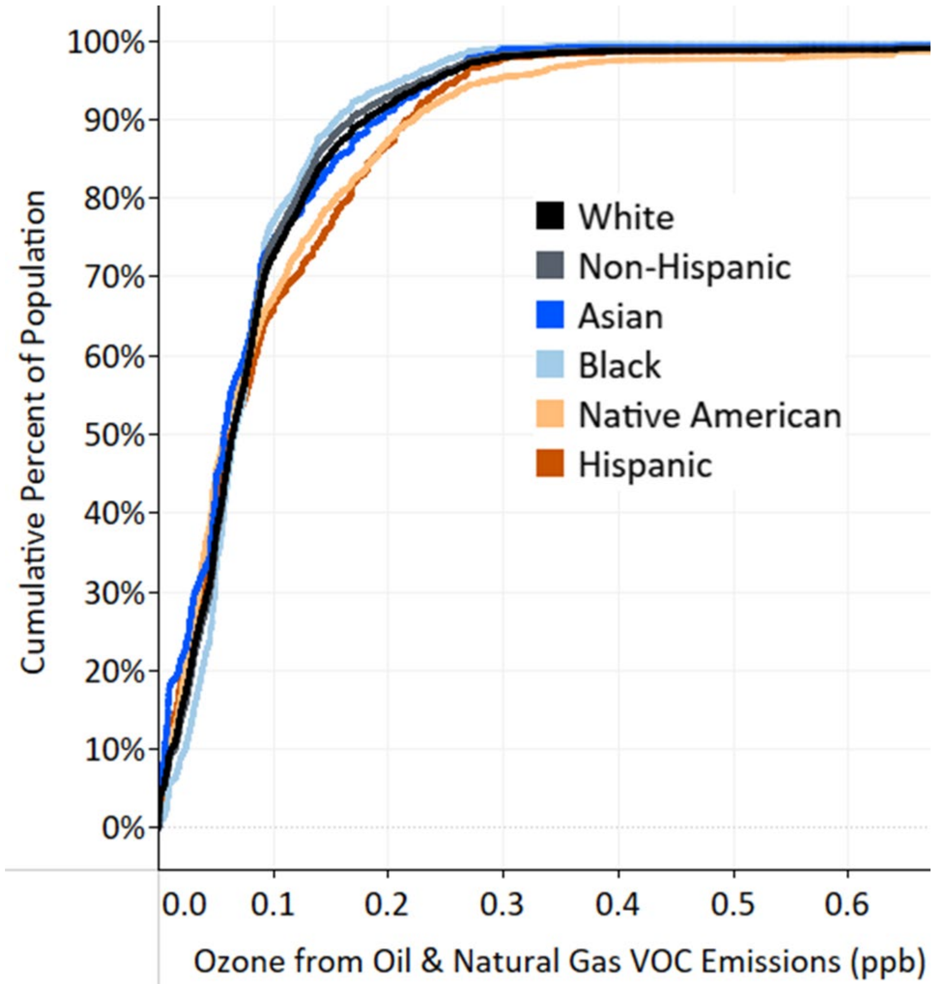

Figure 4-3 Distributions of Ozone from Oil and Natural Gas VOC Emissions Concentrations by Race/Ethnicity

Figure 4-4 shows the distribution of ozone from oil and natural gas VOC emissions across three age ranges, 0–17 shown in blue, 18–64 shown in black, and 65–99 shown in orange. Differences are very small between the three age groups, but the baseline analysis suggests exposure decreases as the age range increases.

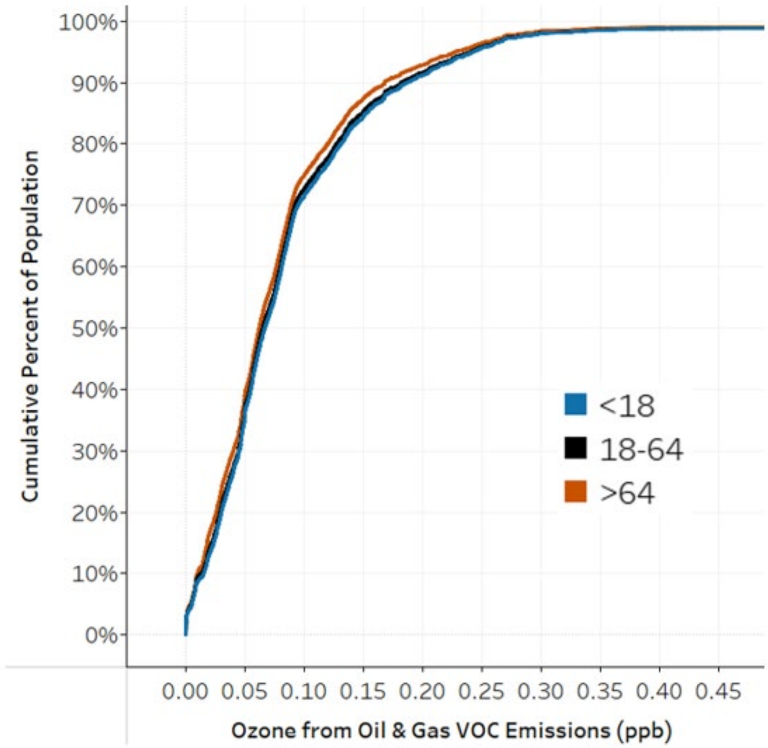

Figure 4-4 Distributions of Ozone from Oil and Natural Gas VOC Emissions Concentrations by Age Range

Figure 4-5 shows the distribution of ozone from oil and natural gas VOC emissions across males (orange) and females (blue) from our analysis. The distribution of exposures is virtually identical between the two sexes.

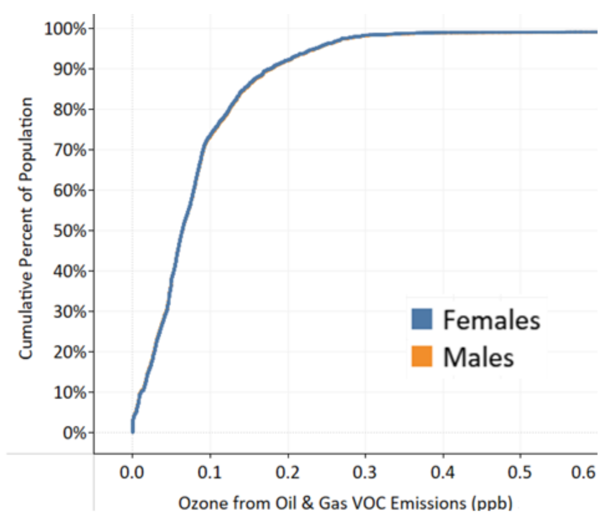

Figure 4-5 Distributions of Ozone from Oil and Natural Gas VOC Emissions Concentrations by Sex

(c) CAP EJ Summary

This recent baseline CAP EJ analysis suggests that there may be some small differences in exposures to ozone formed from VOC emissions from the oil and natural gas sector across races/ethnicities and certain age groups. It also suggests that a substantial portion of ozone from oil and natural gas VOC emissions are localized to rural areas where fewer people reside. However, we lack the data to evaluate this on a more site-specific basis. Additionally, given the size of the sector and the number of oil and natural gas locations, it is quite possible that localized disparities may exist that our analysis did not identify.

4.2.4 Air Toxics Impacts

To evaluate the potential EJ impacts associated with baseline HAP emissions from the oil and natural gas sector, the EPA has assessed the cancer risks and estimated the demographic breakdown of people living in areas with potentially elevated risk levels. Typically, when we perform risk assessments of source categories (e.g., for Risk and Technology Review [RTR] rulemakings), we have detailed location and emissions data for each facility to be assessed and we estimate human health risks at the census block level. For the oil and natural gas sector we do not have such detailed data readily available. We used the most recent National Emissions Inventory (NEI) data from 2017, which indicates nationwide emissions of approximately 110,000 tons of HAP for that year from oil and natural gas sources (see Table 3-6).

The 2017 NEI includes emissions from the sources subject to regulation and sources outside of the regulation. It does not contain refined emissions estimates from only the sources subject to the regulation. The result of this is that we cannot estimate risks from the source category alone, but rather only from the larger industry sector. Another result is that the assessment is considered a screen — it is an estimate of potential risks over a broad area. More refined emissions data would need to be obtained to conduct an assessment where we could draw more accurate conclusions about risk to specific areas and populations.

Most of these emissions (97 percent) are treated as “nonpoint” emissions which are allocated from county-level data down to grid cells (4 km in the continental U.S. (CONUS), 9 km in Alaska) based on emissions surrogates. This means that we are making assumptions about the spatial distribution of these emissions that may not be accurate. The approximately 3 percent of emissions that are categorized as “point” in the NEI are emitted from about 400 facilities across the country. For these sources, we are able to estimate potential exposures and impacts more precisely. Also, we note that some sources categorized as oil and natural gas sources in the NEI are not in the source category for this proposed rule.

The oil and natural gas sector was one of the sectors assessed in the 2014 National Air Toxics Assessment (NATA). In that assessment, the nonpoint emissions were also modeled as 4 km grid cells in CONUS (9 km grid cells in Alaska) and the point emissions were modeled as point sources in the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) using census blocks as model receptors. However, NATA risk estimates were not presented at census block level because of uncertainties associated with the analysis, such as not knowing exactly where in each grid cell the emissions are actually occurring. Instead, NATA risk results were presented at census tract level by population-weighting the block risks up to the tract level. Because census tracts can have large areas, the tract-level risks may not reflect potential elevated risks present at a finer scale. The highest tract-level cancer risk from nonpoint oil and natural gas emissions in the 2014 NATA was 30-in-1 million, and only about 30 tracts (out of approximately 74,000 tracts nationwide) had risks greater than 10-in-1 million. For comparison, the nationwide median *total* cancer risk estimate from the 2014 NATA (considering contributions from all source types) was about 30-in-1 million across all census tracts.

Here, using updated emissions and population data, we have conducted a new analysis of HAP-related exposures and risks across the United States. In this analysis, to assess the potential for elevated risks at a scale finer than the census tract level, we aggregated the block-level AERMOD results from the modeling of the 2017 NEI nonpoint HAP emissions to the same 4 km and 9 km grid cells that nonpoint emissions are allocated to. There are about 500,000 4 km grid cells in CONUS, compared to about 74,000 census tracts so, on average, grid cells are at a finer scale than census tract. For each grid cell, we used the median cancer risk of all the blocks that have their internal point (or centroid) located within the grid cell. Census block demographic data were also aggregated to each 4 km grid cell and risks were calculated at the census blocks from the approximately 400 sources included in the 2017 NEI as point sources and added the highest block-level risk for each point source "facility" to the median cell nonpoint risk for the cell containing the block.

The data used in this analysis include spatial data of the grid cells, 2010 census block location and population data,[65] AERMOD-modeled oil and natural gas 2017 HAP concentrations at census block level for the nonpoint and point sources, and 2015–2019 block-group demographic data. There are separate files for the 4 km grid cells that cover CONUS and the 9 km grid cells for Alaska, each using a Lambert Conformal Conic projected coordinate system. These are the same grid definition used for the 2014 NATA nonpoint oil and natural gas emissions. The census data are for the year 2010, with a small number of changes made to the locations (and sometimes deletions) of specific census blocks based on the RTR pre-modeling review of specific source categories since the 2010 census data were first available (the current oil and natural gas AERMOD modeling is based on the census block receptor file as of May 2019). The AERMOD modeling performed (version 19191) using 2017 NEI and meteorology data followed the same methodology used in the 2014 NATA (U.S. EPA, 2018). Demographic data on total population, race, ethnicity, age, education level, low household income, poverty status and linguistic isolation were obtained from the Census' American Community Survey (ACS) 5-year averages for 2015–2019.[66]

The AERMOD-modeled census block concentrations are based on the 2017 NEI emissions data (see Table 3-6). The process by which emissions were calculated and allocated to grid cells in the case of nonpoint emissions is discussed in the technical support document for the 2017 NEI and the emissions modeling summary for 2017, respectively (U.S. EPA, 2021b; U.S. EPA, 2020b). Emissions data are publicly available online.[67] These emissions were modeled in AERMOD (version 19191), and the resulting block-level annual concentrations of each pollutant were used to calculate cancer risks. The pollutant cancer unit risk estimates used to calculate risks are from the toxicity value files available on the Human Exposure Model website.[68] For each census block, the cancer risks were summed over all pollutants to obtain a total cancer risk.

[65] Data Summary File 1 available at http://www2.census.gov/census_2010/04-Summary_File_1/. See also Technical Documentation for the 2010 Census Summary File 1.
[66] Data available at https://www2.census.gov/programs-surveys/acs/summary_file/2019/data/5_year_entire_sf/.
[67] Data available at https://gaftp.epa.gov/Air/emismod/2017/AERMOD_inputs/.
[68] See https://www.epa.gov/fera/download-human-exposure-model-hem.

The demographic data from the ACS were joined to each census block based on the block group ID (the first 12 characters of the census block ID).

For nonpoint sources, the census blocks were spatially joined to the grid cells (4 km CONUS, 9 km Alaska), and the block data were aggregated at the cell level, using the median cancer risk of the blocks in each cell, and the sum of block populations and the individual demographic group populations (using QGIS version 3.16.3). For point sources, the highest modeled block risk for each facility was added to the median nonpoint risk for the cell containing the block, to provide a measure of total point and nonpoint combined risk.

There are approximately 3 million census blocks with nonzero total risk from oil and natural gas sources based on the AERMOD modeling of the CONUS nonpoint emissions, and these blocks are within approximately 159,000 4 km grid cells. In Alaska, there are approximately 3,500 census blocks with nonzero total risk from oil and natural gas sources based on the AERMOD modeling, and these blocks are within approximately 240 9 km grid cells. In CONUS, the 90th percentile cell risk estimate attributed to oil and natural gas sources is less than 1-in-1 million (0.8-in-1 million) and the 99.9th percentile estimate is 40-in-1 million. The maximum cell risk estimate from oil and natural gas sources is 200-in-1 million, which occurs in two grid cells with an estimated 10 people (3 census blocks,); Carbon County, Wyoming (with an estimated 3 people) and Weld County, Colorado (with an estimated 7 people). The 2014 NATA results for HAP risk from all sources described above (i.e. nationwide median total cancer risk estimate from all source types of approximately 30-in-1 million), can provide context for these risk results for 2017 HAP emissions from oil and natural gas sources. The CONUS results are summarized in Table 4-7. There are about 9500 cells containing about 6.8 million people where the cell risk estimate is greater than 1-in-1 million. There are 122 cells containing about 140,000 people where the cell risk estimate is greater than or equal to 50-in-1 million, and there are 36 cells containing about 40,000 people where the cell risk estimate is greater than or equal to 100-in-1 million. None of the cells in Alaska has estimated cell cancer risk greater than 1-in-1 million.

It is important to reiterate that these risk estimates are based on emissions from the entire oil and gas sector, which includes sources outside the scope of this regulation. To provide some context for how these sources relate to sources impacted by this proposed regulation, we categorized the fraction of oil and natural gas HAP emissions in the 2017 NEI that were attributed to different source types. For this exercise, we specifically focused on formaldehyde and benzene emissions (the two pollutants that accounted for most of the calculated oil and natural gas HAP risk) in the 36 grid cells with 2017 oil and natural gas HAP risk above 100-in-1 million. It is likely that a majority of the formaldehyde emissions and about a quarter of the benzene emissions that were categorized as coming from oil and natural gas sources in the 2017 NEI are from sources outside of this source category. Therefore, it also follows that a majority of the estimated risk is likely being driven by sources not impacted by this proposed regulation. It bears repeating that this is a screening assessment and full modeling would be required to quantitatively split out risk of sources impacted by this rule from other sources categorized in the NEI as oil and natural gas. Risk in grid cells of interest may not scale directly to emissions within the grid cells.

For the point sources, there were 33 sources with estimated census block maximum cancer risk greater than 1-in-1 million, and only 6 sources with estimated risk greater than 10-in-1 million (highest was 40-in-1 million). There was only a single case where the maximum census block risk from a point source, and the median cell risk from nonpoint sources (containing the census block), were both greater than 10-in-1 million. In that case, the point risk of 20-in-1 million and the nonpoint cell risk of 40-in-1 million combined for an estimated 60-in-1 million risk.

Figure 4-6 shows the cell cancer risk estimates in CONUS and Alaska. As indicated in the map, most of the cells in the country (about 150,000 of them) have estimated risk less than 1-in-1 million. Figure 2 is a larger-scale map that shows where the estimated cell risks are the highest. The cells with estimated risk greater than or equal to 30-in-1 million are in Colorado, Utah, Wyoming, and North Dakota, and the cells with the highest estimated risk are all in Colorado.

Table 4-7 also contains estimated numbers of people within various demographic groups who live in areas above the specified risk levels. For nearly all of the demographic groups the percentage of people in the cells with estimated risk above the specified levels is at or below the national average. Above a risk level of 50-in-1 million, the percent minority is about the same as the national average, but the Hispanic/Latino demographic group is about 10 percentage points higher than the national average. The overall minority percentage is not elevated compared to the national average because the African American percentage is much lower than the national average. The demographic group of people aged 0–17 is slightly higher than the national average. For people with estimated risk greater than 1-in-1 million, Hispanic/Latino populations and the age 0–17 group are below the national average, but the percentage of Native American populations is higher than the national average.

Table 4-7 Cancer Risk and Demographic Population Estimates for 2017 NEI Nonpoint Emissions

	Risks ≥ 100-in-1 million		Risks ≥ 50-in-1 million		Risks > 1-in-1 million		Nationwide
Number of Cells	36		122		9499		
Total Population	38,885 (936 census blocks)		142,885 (3204 census blocks)		6,804,691 (172,878 census blocks)		
	Population	%	Population	%	Population	%	%
Minority	13268	34.1	52154	36.5	2,010,161	29.5	39.9
African American	140	0.4	1434	1	535,055	7.9	12.2
Native American	77	0.2	465	0.3	59087	0.9	0.7
Other and Multiracial	1443	3.7	5148	3.6	323,397	4.8	8.2
Hispanic or Latino	11608	29.9	45107	31.6	1,092,621	16.1	18.8
Age 0-17	10679	27.5	37487	26.2	1,463,907	21.5	22.6
Age ≥65	4272	11	17188	12	1,085,067	15.9	15.7
Below the Poverty Level	2000	5.1	13455	9.4	902,472	13.2	13.4
Over 25 Without a High School Diploma	2788	7.2	11320	7.9	488,372	7.2	12.1
Linguistically Isolated	808	2.1	4418	3.1	179,739	2.6	5.4

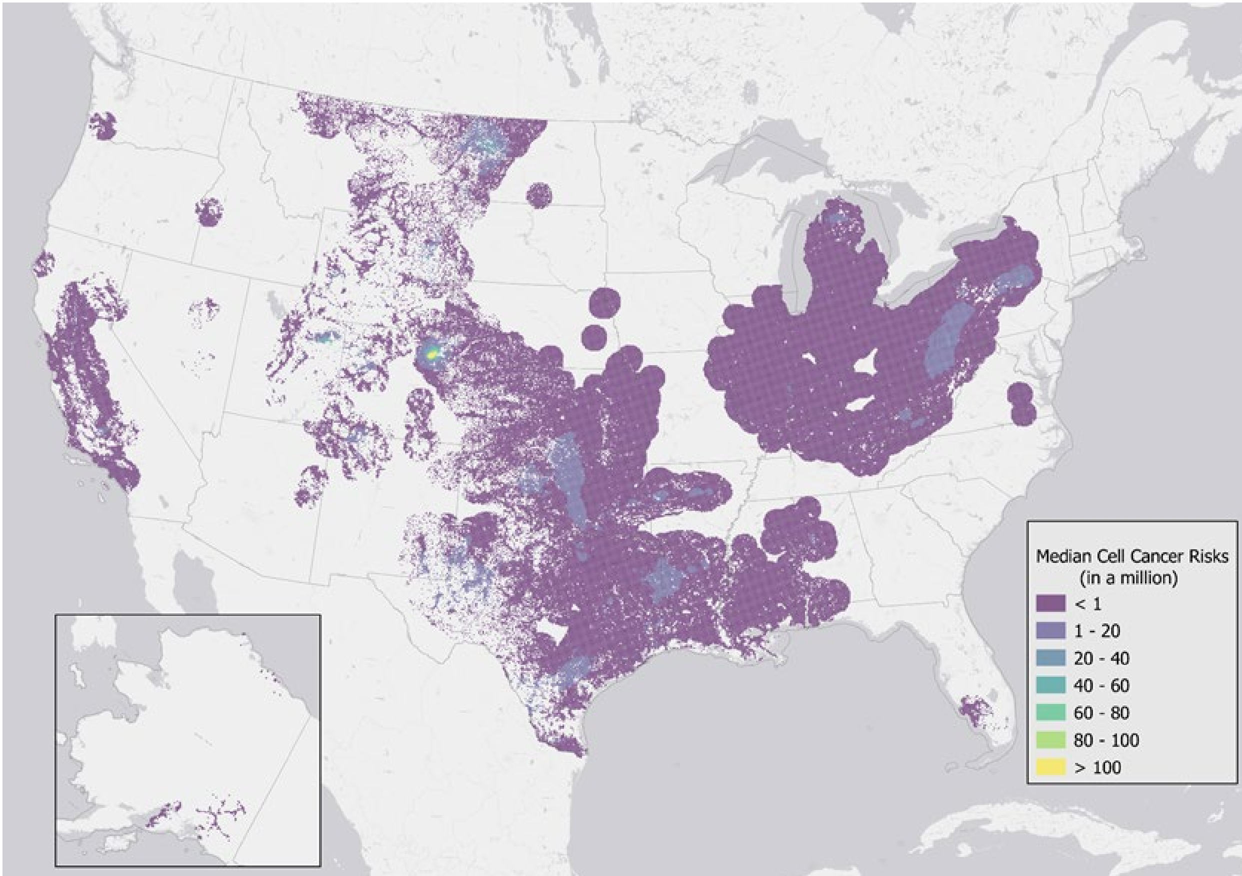

Figure 4-6 National Map of Grid Cell Median Cancer Risks for 2017 Nonpoint Oil and Natural Gas NEI Emissions

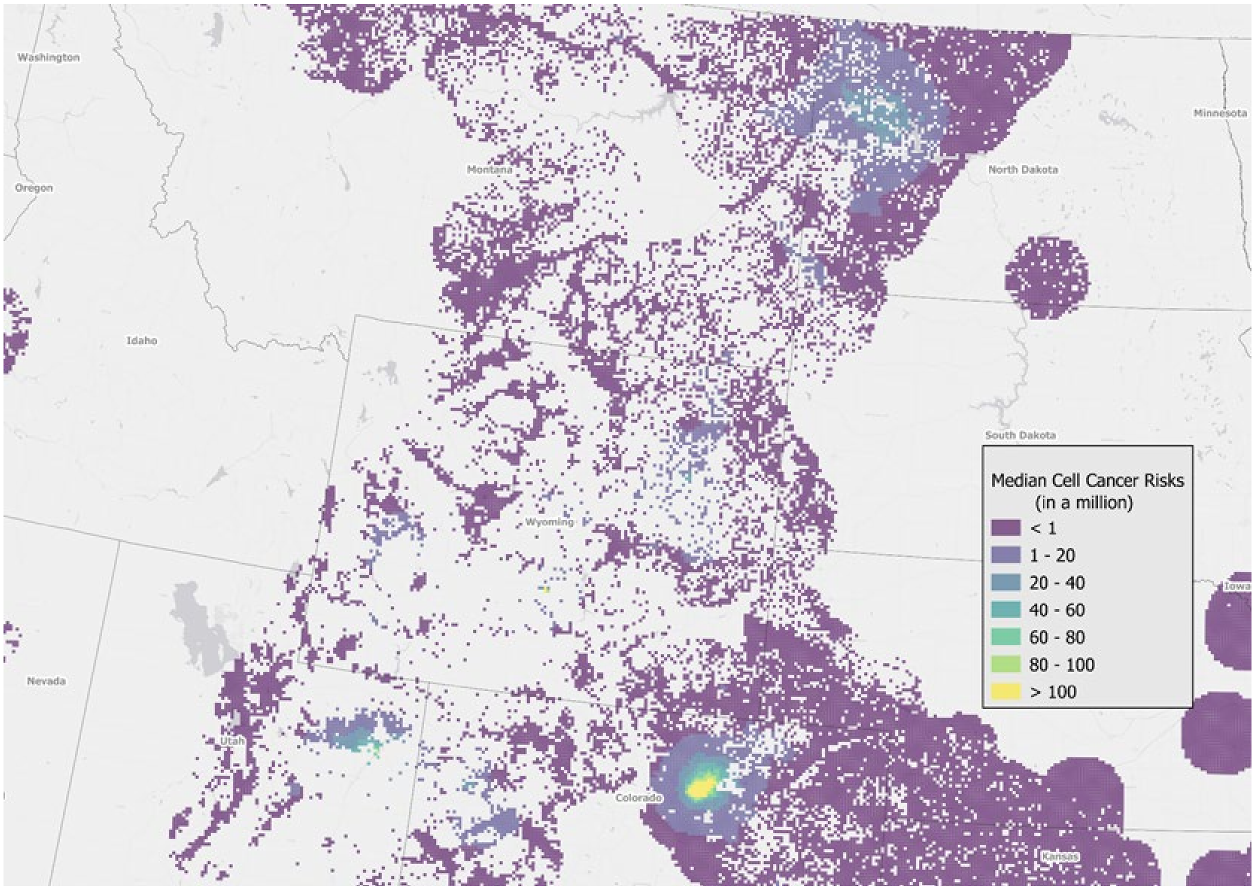

Figure 4-7 Local-Scale Map of Grid Cell Median Cancer Risks for 2017 Nonpoint Oil and Natural Gas NEI Emissions

4.2.5 Demographic Characteristics of Oil and Natural Gas Workers and Communities

The oil and natural gas industry directly employs approximately 140,000 people in oil and natural gas extraction, a figure which varies with market prices and technological change, in addition to a large number of workers in related sectors that provide materials and services. Employment varies with market prices and technological change. Figure 4-8 shows employment since 2001. We see a dramatic increase with the rapid advances in hydraulic fracturing, a decrease after oil prices fell in 2014–2015, and volatility in employment.

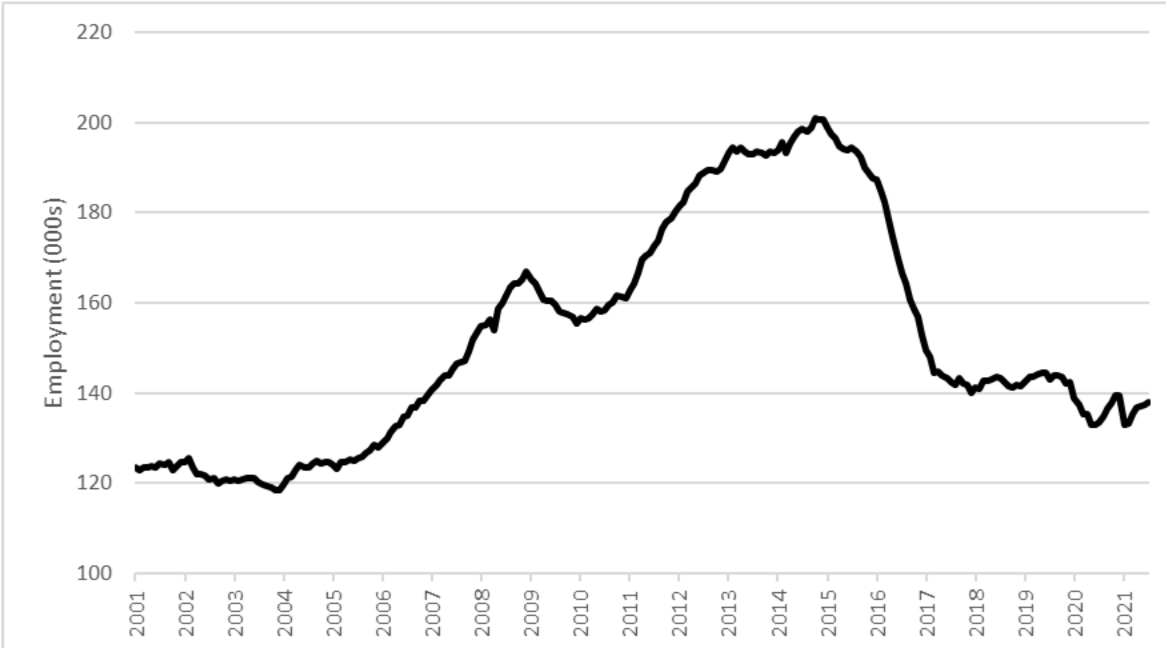

Figure 4-8 National-level Employment in Oil and Natural Gas Production (data from the Bureau of Labor Statistics Current Employment Statistics program for NAICS code 211)

The EPA also conducted a baseline analysis to characterize potential distributional impacts on employment. A reduction in oil and natural gas activity could have a negative effect on employment among oil and natural gas workers. This could also reduce employment, earnings, and tax revenues in oil and natural gas intensive communities.[69] Any effect on oil and natural gas workers or oil and natural gas intensive locations would be a local and partial equilibrium effect. In general equilibrium, there could be other and potentially offsetting effects in other regions and sectors.

For the distribution of employment effects, we assessed the demographic characteristics of 1) workers in the oil and gas sector and 2) people living in oil and natural gas intensive communities. Comparing workers in the oil and natural gas sector to workers in other sectors, oil and natural gas workers may have higher than average incomes, be more likely to have completed high school, and be disproportionately Hispanic. People living in some oil and natural

[69] For this analysis, oil and natural gas intensive communities are defined as the top 20 percent of communities with respect to the proportion of oil and natural gas workers. Some analyses break the top 20 percent into subgroups which are the 80th–95th percentiles, the 95th–97.5th percentiles, and above the 97.5th percentile by proportion of oil and natural gas workers.

gas-intensive communities concentrated in Texas, Oklahoma, and Louisiana, may have disproportionate income levels, rates of high school completion, and demographic composition.

Table 4-8 provides summaries of average income, the percentage of population that is non-Hispanic White, the percentage of population that speaks only English in the home, and the percentage of the population with four years of high school education, all among people with reported income. The table lists these data for the United States, for oil and natural gas workers, for other people, for people in oil and natural gas intensive communities, and for people in other locations. We see that oil and natural gas workers are more highly paid, more likely to be non-Hispanic White individuals, and have higher rates of only speaking English and more likely to have four years of high school than workers in other sectors. People in oil and natural gas communities are demographically similar to people in other communities. This suggests that, on average, reductions in oil and natural gas drilling or production are unlikely to disproportionately impact marginalized communities either via direct labor channels or spillover channels.

Table 4-8 Demographic Characteristics of Oil and Natural Gas Workers and Communities

	Sectors		Places		Overall
	Oil and Natural Gas Workers	**Other People**	**Oil and Natural Gas Communities**	**Other Communities**	**US-wide**
Average Income	$110,000	$42,000	$40,000	$43,000	$42,000
% Non-Hispanic White	81%	71%	68%	69%	71%
% English Only	87%	82%	80%	81%	82%
4 years of High School	97%	88%	86%	88%	88%

Note: Calculations based on United States Census Bureau American Community Survey public use microdata from 2014–2019.

This analysis uses 5-year ACS data from 2015-2019 retrieved from IPUMS. This is approximately 16 million individual ACS responses. Oil and natural gas workers are identified by working in industries with a NAICS code that begins with "211." Those are "Oil and natural gas Extraction," as well as the sub-industries "Crude Petroleum Extraction" and "Natural Gas Extraction."

The level of communities is the Public Use Microdata Area (PUMA). PUMAs are districts defined by the United States Census Bureau. PUMA data is procured from IPUMS. They generally have 100,000–200,000 people with an average of about 140,000 people. The average spatial area of a PUMA is 1,692 square miles. We analyze PUMAs because economic spillovers in this sector occur at a multicounty scale. The oil and natural gas sector includes both substantial intercounty commuting and regional supply chains. Additionally, PUMAs are the smallest geographic unit for which detailed individual data are available. In Table 4-8, oil and natural gas communities are defined as the 20 percent of PUMAs with the highest percentage of oil and natural gas workers. Figure 4-9 shows all PUMAs in the continental United States. Oil and natural gas communities are highlighted.

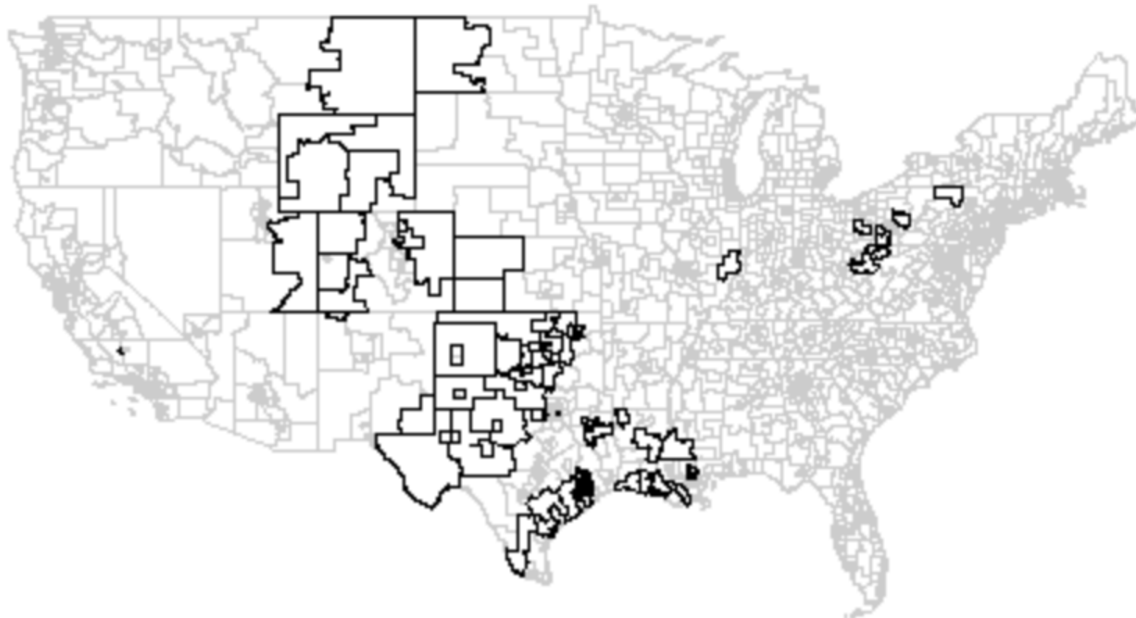

Figure 4-9 Map of PUMAs and Oil and Natural Gas Intensive Communities (Continental United States)

Table 4-9 describes demographics by a region's oil and natural gas (O&G) intensity. Non-oil and natural gas intensive regions (column (1)) are the bottom 80 percent by portion of workers in the oil and natural gas industry. Most of these have no reported oil and natural gas workers. Low oil and natural gas intensive regions (column (2)) are between the 80^{th} and 95^{th} percentiles of oil and natural gas industry employment, high (column (3) are the 95^{th}–97.5^{th}, and very high (column (4)) are above the 97.5^{th} percentile. People in oil and natural gas communities of Table 4-9 are divided between columns (2)–(4). The trimmed comparison group (column (5) is people in non-oil and natural gas intensive regions in states that contain any PUMAs with high or very high intensity. The group of states with high oil and natural gas intensity may be a more appropriate comparison by removing regions of the country which do not resemble oil and natural gas intensive areas, such as the Atlantic coast states.

We see in Block A that people in oil and natural gas intensive communities (columns (2)–(4)) are more likely to be White and Indigenous than people in non-oil and natural gas intensive areas (column (1)). In Block B, we see that people in O&G intensive areas' more likely to be Hispanic than people in non-O&G intensive areas. In Block C, we see income, percentage of population with four years of high school education, and fraction working in the oil and natural gas industry. Comparing people in high and very high oil and natural gas intensity regions (columns (3) and (4)) to people in the trimmed comparison group (column (5)), we see that people in in high oil and natural gas intensity regions are more likely to be White, non-Hispanic, Native American, and less likely to be Asian American or Pacific Islanders.

Table 4-9 Demographic Characteristics of Oil and Natural Gas Communities by Oil and Natural Gas Intensity

	(1)	(2)	(3)	(4)	(5)
	Non-O&G Intensive	**Low O&G Intensity**	**High O&G Intensity**	**Very High O&G Intensity**	**Trimmed Comparison Group**
Block A:					
White	77%	81%	84%	78%	73%
Black and African-American	10%	8%	8%	7%	8%
Native American	1%	2%	2%	3%	1%
Asian American or Pacific Islander	6%	3%	2%	5%	9%
Other Race	4%	3%	2%	4%	7%
Multiple races	2%	2%	2%	3%	3%
Block B:					
Non-Hispanic	88%	84%	86%	81%	80%
Hispanic	12%	16%	14%	19%	20%
Block C:					
Income	$43,000	$39,000	$39,000	$45,000	$43,000
Four years of High School	88%	87%	87%	86%	87%
Fraction Working in O&G	0.00006	0.001	0.004	0.01	0.00008

Note: Calculations based on United States Census Bureau American Community Survey public use microdata from 2014-2019. Numbers may not sum to 100% due to rounding.

Table 4-10 shows the percentage of people by racial group identification for Hispanics and non-Hispanics, across oil and natural gas intensity. We see that people in high and very high intensity communities are more likely to be Hispanic Whites and non-Hispanic Native Americans, and less likely to be non-Hispanic Asian American and Pacific Islanders than people in non oil and gas intensive communities.

Table 4-10 Hispanic Population by Oil and Natural Gas Intensity

	(1) Non-O&G Intensive	(2) Low O&G Intensity	(3) High O&G Intensity	(4) Very High O&G Intensity	(5) Trimmed Comparison Group
Non-Hispanic White	69%	69%	73%	65%	60%
Non-Hispanic Black and African-American	10%	8%	7%	7%	8%
Non-Hispanic Native American	1%	2%	1%	3%	0%
Non-Hispanic Asian American or Pacific Islander	6%	3%	2%	5%	9%
Non-Hispanic Other Race	0%	0%	0%	0%	0%
Non-Hispanic Multiple Races	2%	2%	2%	2%	2%
Hispanic White	8%	12%	11%	14%	12%
Hispanic Black and African-American	0%	0%	0%	0%	0%
Hispanic Native American	0%	0%	0%	0%	0%
Hispanic Asian American or Pacific Islander	0%	0%	0%	0%	0%
Hispanic Other Race	3%	3%	2%	4%	6%
Hispanic Multiple Races	1%	1%	0%	1%	1%

Note: Calculations based on United States Census Bureau American Community Survey public use microdata from 2014-2019. Numbers may not sum to 100% due to rounding.

Marginalized communities are overrepresented in some oil and natural gas intensive communities. Figure 4-10 highlights oil and natural gas intensive communities with substantial EJ communities in darker blue. These communities are in the bottom twenty-five percent by income or high-school graduate or non-Hispanic White population percentage. They are concentrated in Texas, Louisiana, and Oklahoma.

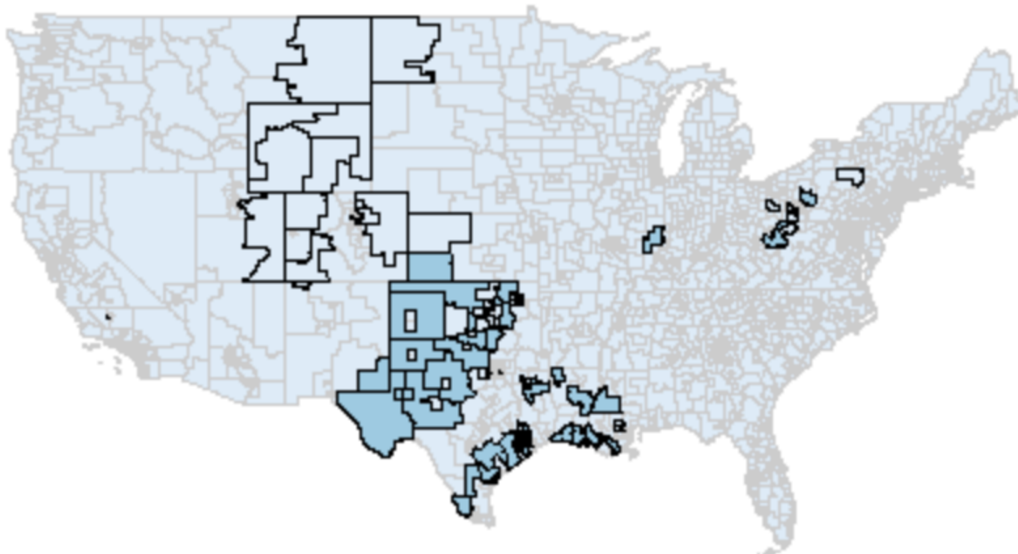

Figure 4-10 Map of Oil and Natural Gas Intensive Communities of Environmental Justice Note

4.2.6 Household Energy Expenditures

Energy provides many services to households that are necessary for a basic standard of living. The proposed regulatory requirements will obligate affected sources to incur costs to reduce emissions, which impact the supply and prices of oil and natural gas and generate energy market impacts, though these impacts are expected to be minimal (see Section 4.1). This section characterizes how household energy expenditures vary across the income distribution and for different racial and ethnic groups. The goal of this section is to highlight which populations and communities may be most vulnerable to potential energy market effects caused by regulatory impacts on the oil and natural gas industry.

Energy insecurity, poverty, and access are important concepts in the discussion of energy burden. Energy insecurity occurs when households lack certainty that they will be able to consume adequate and sufficient energy to meet basic needs. Energy poverty exists when households need to pay disproportionate costs for energy use due to low income, higher energy bills, or inefficient energy use. Energy access barriers exist when households lack access to affordable, reliable energy. Energy insecurity and poverty are persistent problems facing many households across the U.S. (Kaiser and Pulsipher, 2006; EIA, 2018; Bednar and Reames, 2020) and they have many consequences for human health and wellbeing (Hall, 2013; Jessel et al. 2019; Karpinksa, 2020). The EIA found that nearly a third of U.S. households faced challenges paying their energy bills or could not maintain adequate heating or cooling in 2015. For purposes of this section, "energy burden" focuses primarily on energy poverty.

Low-income and minority households tend to face disproportionately high energy burdens (Hernández et al. 2014; Wang et al. 2021) and thus are particularly vulnerable when energy prices increase. Although these households consume less energy, energy tends to represent a larger share of their budgets. Drehobl, Ross, and Ayala (2020) find that low-income, Black, Hispanic, Native American, and older adult households have disproportionally higher energy burdens than the average household. Lyubich (2020) finds that Black households spend more on residential energy than White households even after controlling for income, household size, city, and homeowner status. Wang et al. (2021) find that Black households spent more on energy than other households at every point on the income distribution, suggesting that energy efficiency issues may be more problematic in Black households. They identify geographic location, climate, the characteristics of dwellings, and socioeconomic characteristics as primary drivers of residential energy use and energy burden.

To investigate baseline energy expenditures and potential distributional impacts of possible increases in energy costs, we assessed expenditure and income data stratified by pre-tax income quintiles and race/ethnicity from the 2019 Consumer Expenditure Survey (CES) from the U.S. Bureau of Labor Statistics. We combined expenditures in the following four categories to approximate "energy expenditures": (1) Natural gas, (2) Electricity, (3) Fuel oil and other fuels, and (4) Gasoline, other fuels, and motor oil (transportation). The first three categories are residential energy expenditures and the fourth category represents transportation energy expenditures. These categories are assumed to potentially experience price impacts due to regulatory costs affecting the oil and natural gas industry, though we expect impacts to be minimal.

We examined energy expenditures, the ratio of household energy expenditures to total household expenditures, and the ratio of household energy expenditures to after-tax income across income quintiles and racial groups. It is important to note that energy burden is sensitive to the particular energy services and expenditures are included and how income is defined (e.g., whether transfer payments or taxes are included in income calculation; the inclusion of transportation-related energy expenditures).

Table 4-11 shows energy expenditures by quintiles of pre-tax income. The data indicate that the highest income group consumes the most energy and spends the most per household on it, but energy expenditures represent a smaller percentage of their total expenditures and a much smaller percentage of their income than the lowest income quintile. Energy expenditures as a share of total household expenditures were 8.3 percent for the lowest income quintile and 4.9 percent for the highest income quintile. For energy expenditures as a share of average after-tax income, the distribution is more unequal, ranging from 19.4 percent for the lowest income quintile to 3.4 percent for the highest income quintile. This means the lowest income households are spending over five times more of their income on energy than the highest income households.

Table 4-11 Energy Expenditures by Quintiles of Income before Taxes, 2019

	All	Lowest 20%	Second 20%	Third 20%	Fourth 20%	Highest 20%
Income after taxes	71,487	12,236	32,945	53,123	83,864	174,777
Annual expenditures	63,036	28,672	40,472	53,045	71,173	121,571
Natural gas	416	259	355	367	455	644
Electricity	1,472	1,049	1,351	1,446	1,587	1,924
Fuel oil and other fuels	113	69	101	86	121	189
Gasoline, other fuels, and motor oil (transportation)	2,094	998	1,601	2,079	2,593	3,193
Energy expenditures	4,095	2,375	3,408	3,978	4,756	5,950
Energy expenditures as share of total expenditures	6.5%	8.3%	8.4%	7.5%	6.7%	4.9%
Energy expenditures as share of income	5.7%	19.4%	10.3%	7.5%	5.7%	3.4%
Quintile share of all energy expenditures		11.6%	16.7%	19.4%	23.2%	29.1%

Source: Consumer Expenditure Survey, U.S. Bureau of Labor Statistics, September, 2020. https://www.bls.gov/cex/tables/calendar-year/mean-item-share-average-standard-error.htm#cu-income. Accessed 5/27/2021.
Note: Income includes wages, self-employment income, Social Security and retirement payments, interest, dividends, rental income and other property income, public assistance, unemployment and workers' compensation, veterans' benefits, and regular contributions for support.

The EPA also examined the household energy expenditure data by race and ethnicity. The data indicate that Black households' energy expenditures represent a higher share of their total expenditures and income than for households of other races, yet their energy expenditures were lower. Hispanic households' energy expenditures comprise a larger share of their total expenditures and income than non-Hispanic households, though they spent slightly more per household on energy than non-Hispanic households.

The CES data summarized in this section highlight the disproportionately high energy burdens experienced particularly by low-income households, as well as Black and Hispanic households to some extent. These households must allocate a greater share of their incomes and expenditures to energy, reducing disposable income that could be used for other essentials (e.g., housing, healthcare, and food) and other non-essential preferences. Thus, low income, Black, and Hispanic households are expected to be most likely to be adversely affected by any potential increases in energy costs due to this proposed rule because they face higher energy burdens under the baseline. Nonetheless, since energy cost impacts are expected to be minimal, this rule is not expected to significantly alter existing levels of inequality in energy burden.

4.2.7 Summary

EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis. For the proposal, we quantitatively and qualitatively evaluated baseline scenarios for several potential EJ concerns, although data availability limitations and the large number of oil and natural gas locations make it quite possible that disparities may exist that our analysis did not identify. This is especially relevant for potential EJ characteristics that were not evaluated, such as lower educational attainment. It is also possible that the proposed rulemaking shifts the distribution of impacts, but our analysis did not assess policy-specific impacts.

Some commonalities emerged across the array of EJ analysis. Notably, more Hispanic people may reside in communities with potentially elevated cancer risk from oil and natural gas-related toxic emissions (Section 4.2.3). Similarly, Hispanic populations may experience disproportional exposures to air pollutants from the oil and natural gas industry (Sections 4.2.3 and 4.2.4) and may be more likely to reside in communities of higher oil and natural gas intensity (Section 4.2.5). Additionally, Hispanic households' energy expenditures may comprise a disproportionate share of their total expenditures and income as compared to non-Hispanic households (Section 4.2.6). However, uncertainties associated with the input data, as well as the meaningfulness of any differences, should be taken into consideration when interpreting these results. Additionally, we lack key information that would be needed to characterize post-control risks under the proposed NSPS OOOOb and EG OOOOc or the regulatory alternatives analyzed in the RIA, preventing the EPA from analyzing spatially differentiated outcomes. While a definitive assessment of the impacts of this proposed rule on minority populations, low-income populations, and/or Indigenous peoples was not performed, the EPA believes that this action will achieve substantial methane, VOC, and HAP emissions reductions and will further improve environmental justice community health and welfare. The EPA believes that any potential environmental justice populations that may experience disproportionate impacts in the baseline may realize disproportionate improvements in air quality resulting from emissions reductions.

4.3 Initial Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA; 5 U.S.C.§ 601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 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 (IRFA), 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. An IRFA describes the economic impact of the proposed rule on small entities and any significant alternatives to the proposed rule that would accomplish the objectives of the rule while minimizing significant economic impacts on small entities. Pursuant to section 603 of the RFA, the EPA prepared an IRFA that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact.

4.3.1 Reasons Why Action is Being Considered

The proposed rulemaking takes a significant step forward in mitigating climate change and improving human health by reducing GHG and VOC emissions from the oil and natural gas industry, specifically the Crude Oil and Natural Gas source category. The oil and natural gas industry is the United States' largest industrial emitter of methane. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. According to the Intergovernmental Panel on Climate Change (IPCC), strong, rapid, and sustained methane reductions are critical to reducing near-term disruption of the climate system and a vital complement to carbon dioxide (CO_2) reductions critical in limiting the long-term extent of climate change and its destructive impacts. The oil and natural gas industry also emits other health-harming pollutants in varying concentrations and amounts, including CO_2, VOC, sulfur dioxide (SO_2), nitrogen oxide (NO_X), hydrogen sulfide (H_2S), carbon disulfide (CS_2), and carbonyl sulfide (CO_S), as well as, benzene, toluene, ethylbenzene and xylenes (this group is commonly referred to as ''BTEX''), and n-hexane.

The EPA is proposing the actions described in the preamble in accordance with its legal obligations and authorities following a review directed by EO 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," issued on January 20, 2021. The EPA intends for the proposed actions to address the far-reaching harmful consequences and real economic costs of climate change. According to the IPCC, "It is unequivocal that human influence has warmed the atmosphere, ocean and land. Widespread and rapid changes in the atmosphere, ocean, cryosphere and biosphere have occurred." These changes have led to increases in heat waves and wildfire weather, reductions in air quality, more intense hurricanes and rainfall events, and rising sea level. These changes, along with future projected changes, endanger the physical survival, health, economic well-being, and quality of life of people living in America, especially those in the most vulnerable communities.

In the proposed action, the EPA has taken a comprehensive analysis of the most attainable data from emission sources in the Crude Oil and Natural Gas source category and the latest available information on control measures and techniques to identify achievable, cost-effective measures to significantly reduce emissions, consistent with the requirements of section 111 of the CAA. If finalized and implemented, the proposed actions would lead to significant and cost-effective reductions in climate and health-harming pollution and encourage development and deployment of innovative technologies to further reduce this pollution in the Crude Oil and Natural Gas source category.

4.3.2 Statement of Objectives and Legal Basis for Proposed Rules

The EPA proposes to revise certain NSPS and to promulgate additional NSPS for both methane and VOC emissions from new oil and gas sources in the production, processing, transmission and storage segments of the industry; and to promulgate EG to require states to regulate methane emissions from existing sources in those segments. The large amount of methane emissions from the oil and natural gas industry — by far, the largest methane-emitting industry in the nation — coupled with the adverse effects of methane on the global climate compel immediate regulatory action.

The proposal is in line with our 2016 NSPS OOOOa Rule, which likewise regulated methane and VOCs from all three segments of the industry. The 2016 NSPS OOOOa Rule explained that these three segments should be regulated as part of the same source category because they are an interrelated sequence of functions in which pollution is produced from the same types of sources that can be controlled by the same techniques and technologies. That Rule further explained that the large amount of methane emissions, coupled with the adverse effects of GHG air pollution, met the applicable statutory standard for regulating methane emissions from new sources through NSPS. Furthermore, the Rule explained, this regulation of methane emissions from new sources triggered the EPA's authority and obligation to regulate the overwhelming majority of oil and gas sources, which the CAA categorizes as "existing" sources. In the 2020 Policy Rule, the Agency reversed course, concluding based upon new legal interpretations that it was not authorized to regulate the transmission and storage segment or to regulate methane. In 2021, Congress adopted a joint resolution to disapprove the EPA's 2020 Policy rule under the CRA. According to the terms of CRA, the 2020 rule is "treated as though [it] had never taken effect," 5 U.S.C. 801(f), and as a result, the 2016 rule is reinstated.

In disapproving the 2020 Policy Rule under the CRA, Congress explicitly rejected the 2020 Policy Rule interpretations and embraced the EPA's rationales for the 2016 NSPS OOOOa Rule. The House Committee on Energy & Commerce emphasized in its report (House Report) that the source category "is the largest industrial emitter of methane in the U.S.," and directed that "regulation of emissions from new and existing oil and gas sources, including those located in the production, processing, and transmission and storage segments, is necessary to protect human health and welfare, including through combatting climate change, and to promote environmental justice." House Report at 3-5. A statement from the Senate cosponsors likewise underscored that "methane is a leading contributing cause of climate change," whose "emissions come from all segments of the Oil and Gas Industry," and stated that "we encourage EPA to strengthen the standards we reinstate and aggressively regulate methane and other pollution emissions from new, modified, and existing sources throughout the production, processing, transmission and storage segments of the Oil and Gas Industry under section 111 of the CAA." Senate Statement at S2283. The Senators concluded with a stark statement: "The welfare of our planet and of our communities depends on it." Id.

The proposed rule comports with the EPA's CAA section 111 obligation to reduce dangerous pollution and responds to the urgency expressed by the current Congress. With the proposal, the EPA is taking additional steps in the regulation of the Crude Oil and Natural Gas source category to protect human health and the environment. Specifically, the agency is proposing to revise certain of those NSPS, to add NSPS for additional sources, and to propose EG that, if finalized, would impose a requirement on states to regulate methane emissions from existing sources. As the EPA explained in the 2016 rule, this source category collectively emits massive quantities of the methane emissions that are among those driving the grave and growing threat of climate change, particularly in the near term. 81 FR at 3584. Since that time, the science has repeatedly confirmed that climate change is already causing dire health, environmental, and economic impacts in communities across the United States.

Because the 2021 CRA resolution automatically reinstated the 2016 rule, which itself determined that the Crude Oil and Natural Gas Source Category included the transmission and storage segment and that regulation of methane emissions was justified, the EPA is authorized to take the regulatory actions proposed in the rule. In addition, in this action, we are reaffirming those determinations as clearly authorized under any reasonable interpretation of section 111. Further information can be found in section VIII of the preamble.

4.3.3 Description and Estimate of Affected Small Entities

The Regulatory Flexibility Act (RFA) defines small entities as including “small businesses,” “small governments,” and “small organizations” (5 USC 601). The regulatory revisions being considered by EPA for this rulemaking are expected to affect a variety of small businesses but would not affect any small governments or small organizations. The RFA references the definition of “small business” found in the Small Business Act, which authorizes the Small Business Administration to further define “small business” by regulation. The detailed listing of SBA definitions of small business for oil and natural gas industries or sectors, by NAICS code, that are potentially affected by this proposal is included in Table 4-12. The EPA conducted this initial regulatory flexibility analysis at the ultimate (i.e., highest) level of ownership, evaluating parent entities.

Table 4-12 SBA Size Standards by NAICS Code

NAICS Codes	NAICS Industry Description	Size Standards (in millions of dollars)	Size Standards (in no. of employees)
211120	Crude Petroleum	-	1,250
211130	Natural Gas Extraction	-	1,250
213111	Drilling Oil and Gas Wells	-	1,000
213112	Support Activities for Oil and Gas Operations	$41.5	-
486210	Pipeline Transportation of Natural Gas	$30.0	-

Sources: U.S. Small Business Administration, Table of Standards, Effective August 19, 2019. https://www.sba.gov/document/support--table-size-standards. Accessed September 9, 2021.

To estimate the number of small businesses potentially impacted by the rule, we developed a list of operators of oil and natural gas wells and natural gas processing plants based on data from Enverus (wells) and EIA (processing plants); data on operators of compressor stations was not available to the EPA at the time of the analysis. The list of well operators consists of operators of wells completed in 2019, which serves as an approximation of the universe of operators that might be affected in future years by updates to the NSPS. The list of processing plant operators consists of all operators of natural gas processing plants in the EIA dataset for 2017 (the most recent year available).[70] The dataset does not have information on construction dates of plants, so a representative subset of operators of recently constructed plants could not be created as it was for wells. In total, the operator dataset consists of approximately 2,000 unique operator names across both segments.[71]

Using an approximate string-matching algorithm, we merged the list of operators with business information from D&B Hoovers to obtain information on NAICS codes (both own and ultimate parent), number of employees, and annual revenues. The algorithm matched 1,267 (65 percent) of the operators to NAICS codes with a valid SBA size classification threshold. Each matched operator was coded as small business (1,096 operators), not small business (162), or unknown (9) by comparing the estimated employee counts and annual revenues from D&B Hoovers with the SBA size classification thresholds. Unknown entities were missing the applicable employee count or annual revenue estimates. The results of the small business coding exercise are displayed by NAICS code in Table 4-13.

[70] Data available at https://www.eia.gov/naturalgas/ngqs/#?report=RP9&year1=2017&year2=2017&company=Name.

[71] This figure does not necessarily mean that it represents 2,000 unique operators, as duplicates were only removed for exact string matches. For example, Oil and Gas LLC and Oil & Gas LLC would be represented as two unique entities.

Table 4-13 **Counts and Estimated Percentages of Small Entities**

NAICS Codes	NAICS Industry Description	Number of Firms Identified	Estimated Number of Small Entities	Estimated Percentage of Small Entities for Identified Firms
211120	Crude Petroleum	346	322	93%
211130	Natural Gas Extraction	5	5	100%
213111	Drilling Oil and Gas Wells	60	58	97%
213112	Support Activities for Oil and Gas Operations	373	326	87%
486210	Pipeline Transportation of Natural Gas	33	11	33%
Many[a]	Other	431	373	87%

[a] Not all owner/operators in the Enverus well database produced a match in the D&B Hoovers database under an oil and natural gas industry-related NAICS as presented in Table 4-12.

4.3.4 Compliance Cost Impact Estimates

To estimate the compliance cost impacts on small entities of the proposed rule, we use the dataset of operators discussed in the previous section and apply the sum of incremental costs for all relevant affected facility categories. Because the incremental costs depend on unknown information about the characteristics of operator-specific well sites and processing plants, we use a Monte Carlo simulation approach to derive estimates of average impacts given distributions of the characteristics of sites across all operators. Ultimately, we estimate cost-to-sales ratios (CSR) for each small entity to summarize the impacts of the proposed rule.

4.3.4.1 Methodology for Estimating Impacts on Small Entities

There two main pieces of information we use to assess impacts on small entities are operator revenues and expected compliance costs. For most operators in the dataset described in the previous section, revenues are generated from the match with the D&B Hoovers database. For well site operators for which annual revenues could not be obtained from D&B Hoovers, we estimated revenues by calculating total operator-level production in 2019 from Enverus and multiplying by assumed oil and natural gas prices at the wellhead. For natural gas prices, we assumed the projected price from AEO in 2022, $3.27/Mcf. For oil prices, we estimated revenues using the projected AEO price for Brent Crude in 2022, $49.4/barrel. Both prices are measured in 2019$. Altogether, this procedure yielded approximately 1,600 operators across production and processing for which we had revenue estimates. Some of these 1,600 operators may be present in both the production and processing segments; when this is the case, these operators are counted separately in each segment and treated as distinct entities for the purpose of the analysis. Of those operators, more than 60 percent are estimated to be small entities, based on the data from D&B Hoovers and SBA size standards. Another third could not be mapped to a valid NAICS, and so their small business status is unknown. Summary statistics for company revenues by segment are presented in Table 4-14.

Table 4-14 Summary Statistics for Revenues of Potentially Affected Entities

Segment	Size	No. of Firms	Mean Revenue	Median Revenue
Production	Small	1,411	$50,000,000	$1,400,000
	Not Small	88	$8,500,000,000	$340,000,000
Processing	Small	112	$190,000,000	$5,500,000
	Not Small	60	$20,000,000,000	$8,300,000,000

To calculate expected compliance costs for operators, we first constructed an estimate of the number of sites for each operator. For well site operators, we calculated the number of sites by using Enverus well pad identifiers to match wells from the 2019 completion data with sites. Because compliance costs are different for oil versus natural gas wells, we classified the sites for each operator as either oil or natural gas based on site-level GOR using 2019 production data from Enverus. If site-level GOR couldn't be calculated, then classification was based on the Enverus production type variable.[72] Finally, if assignment couldn't be made based on site-level GOR or Enverus production type, we assigned the site based on operator GOR, which includes all sites with production in 2019, regardless of whether they had a completion in 2019. For processing plant operators, the number of sites is obtained by summing the number of entries in the EIA data for each operator, since each entry represents one processing plant.

Once site type counts were assigned to operators, we estimated expected compliance costs for each operator by assigning costs from all relevant affected facilities: fugitive emissions, pneumatic controllers, storage vessels, and liquids unloading for well sites and equipment leaks and reciprocating compressors for natural gas processing plants.[73] Since the precise equipment and emissions at the well site level were necessary to estimate compliance costs relative to

[72] If at least one well at a site was classified as "OIL" or "OIL AND GAS," then we assigned the site as oil. For the remaining unassigned sites, if at least one well at a site was classified as "GAS," then we assigned the site as natural gas.

[73] There are other affected facility types within each segment for which the NSPS requirements are not changing relative to the baseline.

baseline, and this information was not present in the Enverus database, a Monte Carlo approach was used; see Section A.2 for a description of how these equipment and emissions distributions were used to estimate site-level compliance costs for this analysis. Once site-level costs were estimated for each entity, these were summed over operator and segment. Average compliance costs by segment and firm size are presented in Table 4-15, both with and without expected revenue from product recovery included.

Table 4-15 Distribution of Estimated Compliance Costs across Segment and Firm Size Classes (2019$)[a]

Segment	Size	No. of Firms	Average Cost with Product Recovery	Average Cost without Product Recovery
Production: Primary Proposal	Small	1411	$4,900	$14,000
	Not Small	88	$12,000	$53,000
Production: Co-Proposal	Small	1411	$4,300	$13,000
	Not Small	88	$10,000	$50,000
Processing	Small	112	($75,000)	($67,000)
	Not Small	60	($90,000)	($80,000)

[a] Compliance cost estimates presented in the table do not include costs for small entity owner/operators of compressor stations, However, these requirements affecting owner/operators of compressor stations account for a small fraction of the potential impact of the proposed NSPS.
Note: sums may not total due to independent rounding.

4.3.4.2 Results

This section presents results of the cost-to-sales ratio analysis for the production and processing segments. In the processing segment, average costs relative to baseline are expected to be negative, and no entity has a CSR greater than either 1 percent or 3 percent.[74] In the production segment, when expected revenues from natural gas product recovery are included, 349 small entities (25 percent) have cost-to-sales greater than 1 percent, while 155 have cost-to-sales ratios greater than 3 percent (12 percent). When expected revenues from natural gas product recovery are excluded, the number of small entities with cost-to-sales ratios greater than 1 percent increases to 588 (44 percent); about half of those small entities (25 percent) also have cost-to-

[74] The net compliance costs for leak detection at natural gas processing plants decrease primarily because OGI surveys under this proposal can be conducted much more quickly and at approximately half the cost of EPA Method 21 surveys under the current requirements in NSPS VVa, so the increased flexibility under the proposal is likely cost saving for affected facilities.

sales ratios greater than 3 percent. These figures do not differ substantially between the primary proposed option and the co-proposed option, as shown in Table 4-16.

Table 4-16 Compliance Cost-to-Sales Ratios for Small Entities[a]

Segment		With Product Recovery Included		Without Product Recovery Included	
		No. of Small Entities	% of Small Entities	No. of Small Entities	% of Small Entities
Production: Primary Proposal	No. of Small Entities	1,412	100%	1,412	100%
	Greater than 1%	349	25%	588	44%
	Greater than 3%	155	12%	336	25%
Production: Co-Proposal	No. of Small Entities	1,412	100%	1,412	100%
	Greater than 1%	338	24%	608	43%
	Greater than 3%	154	11%	351	25%
Processing	No. of Small Entities	112	100%	112	100%
	Greater than 1%	0	0.00%	0	0.00%
	Greater than 3%	0	0.00%	0	0.00%

[a] Compliance cost estimates presented in the table do not include costs for small entity owner/operators of compressor stations, However, these requirements affecting owner/operators of compressor stations account for a small fraction of the potential impact of the proposed NSPS.

4.3.5 Caveats and Limitations

The analysis above is subject to several caveats and limitations, many of which we discussed in the presentation of methods and results. It is useful, however, to present a complete list of the caveats and limitation here.

- Because of data limitations, the analysis presented in the IRFA does not examine impacts on owner/operators of compressor stations in the gathering and boosting and transmission and storage segments. While impacts from these requirements do not constitute a large proportion of the estimated impacts from the proposed NSPS, the omission of the cost impacts to owner/operators of these facilities leads to a relative under-estimate of the impacts on small entities.
- Not all owner/operators listed in the Enverus well database could be identified in the D&B Hoovers database. These owner/operators tend to have developed relatively few new or modified wells in 2019. As a result, we assumed these were small entities, whereas these entities may be subsidiaries of larger enterprises. This assumption likely

leads to an over-estimate of the impact on small entities for the provisions examined. In addition, the matching procedure used to link the operator database to the D&B Hoovers database is imperfect, and so there may be misspecified matches or duplicate entries for the same entity.

- The analysis assumes the same population of entities completing wells in 2019 are also completing wells in in 2023 and beyond. In the future, many of these firms will complete fewer or more wells, and other firms will complete wells. These firms combined may complete new or modified wells at higher or lower rates depending on economics and technological factors that are largely unpredictable.
- The approach used to estimate sales for the cost-to-sales might over-estimate or under-estimate sales depending upon the accuracy of the information in the underlying databases and the market prices ultimately faced when the proposed requirements are in effect.
- It is unknown what equipment is present at each site, and therefore the Monte Carlo approach used to estimate costs may under- or over-estimate costs at the site level for each entity, which adds uncertainty to the calculated cost-to-sales ratios.

4.3.6 Projected Reporting, Recordkeeping and Other Compliance Requirements

The information to be collected for the proposed NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which facilities, records, or processes may need inspection. All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

Potential respondents under subparts OOOOa and OOOOb are owners or operators of new, modified, or reconstructed oil and natural gas affected facilities as defined under the rule. Few, if any, of the facilities in the United States are owned or operated by state, local, tribal or the Federal government. The regulated facilities are privately owned for-profit businesses. The requirements in this action result in industry recording keeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information, performing initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and train personnel to be able to respond to the collection of information.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOa for the estimated 3,268 owners and operators that are subject to the rule is approximately 280,000 labor hours, with an annual average cost of about $94 million. The annual public reporting and recordkeeping burden for this collection of information is estimated to average about 87 hours per respondent. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

4.3.7 Related Federal Rules

There are two National Emission Standards for Hazardous Air Pollutants (NESHAP) rules that apply to certain equipment and processes in the oil and natural gas sector. These rules, listed below, address air toxics, primarily benzene, toluene, ethylbenzene, and xylenes (collectively referred to as BTEX) and n-hexane. These two rules were promulgated under section 112 of the Clean Air Act and are codified in 40 CFR Part 63 Subpart HH and Subpart HHH.

Aside from the EPA, several other Federal agencies have jurisdiction over the oil and natural gas sector.

- The Bureau of Land Management (BLM) within the Department of the Interior regulates the extraction of oil and gas from federal lands. BLM manages the Federal government's onshore subsurface mineral estate, about 700 million acres. BLM also oversees oil and gas operations on many Tribal leases and maintains an oil and natural gas leasing program. BLM does not directly regulate emissions for the purposes of air quality but does regulate venting and flaring of natural gas for the purposes of preventing waste. An operator may also be required to control/mitigate emissions as a condition of approval on a drilling permit.

- The Bureau of Ocean Energy Management (BOEM) within the Department of the Interior manages the development of America's offshore energy and mineral resources. BOEM has air quality jurisdiction in the Gulf of Mexico and the North Slope Borough of Alaska and in federal waters on the Outer Continental Shelf 3–9 miles offshore.
- The Pipeline and Hazardous Materials Safety Administration (PHMSA) within the Department of Transportation ensures safety in the design, construction, operation, maintenance, and spill response planning of America's 2.8 million miles of natural gas and hazardous liquid transportation pipelines. This includes data and risk analysis, outreach, research and development, regulations and standards, training, inspections and enforcement and accident investigations. Section 113 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020) mandates that PHMSA promulgate a final rule concerning gas pipeline leak detection and repair programs no later than one year after the enactment of the law.
- The Federal Energy Regulatory Commission (FERC) within the Department of Energy regulates natural gas pipeline, storage, and liquefied natural gas facility construction. FERC also issues environmental assessments or draft and final environmental impact statement for comment on most projects.
- The Internal Revenue Service (IRS), in the Internal Revenue Code (IRC), defines a stripper well property as "a property where the average daily production of domestic crude oil and gas produced from the wells on the property during a calendar year divided by the number of such wells is 15 barrel equivalents or less." See IRC 613A(c)(6)(E).

4.3.8 Regulatory Flexibility Alternatives

The Small Business Advocacy Review (SBAR) Panel has reviewed the information provided by the EPA to the small entity representatives (SERs) and the SERs' oral and written comments from the pre-panel outreach and panel outreach. In response to this consultation, the Panel identifies the following significant alternatives for consideration by the Administrator of the EPA which accomplish the stated objectives of the Clean Air Act and which minimize any significant economic impact of the proposed rule on small entities.

4.3.8.1 Rule Scope

SERs stated that NSPS OOOOa has unintentionally been applied to conventional and vertical wells that engage in hydraulic fracturing. SERs contend that these wells have a very different profile from unconventional and horizontal wells in terms of footprint, water usage, chemical usage, equipment used, and flowback period. SERs recommend that the EPA explicitly exempt conventional and vertical wells from the proposal. The EPA maintains that the original intend of the NSPS was to regulate hydraulicly fractured wells, in both conventional and unconventional reservoirs, and both vertical and horizontal wells.

NSPS OOOOa defines hydraulic fracturing as “the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.” The NSPS does not offer numeric thresholds that define “pressurized fluids,” “tight formations,” or “high rate, extended flowback.” When developing the original NSPS OOOO, the EPA’s analysis assumed hydraulic fracturing is performed in tight sand, shale, and coalbed methane formations to have an in situ permeability (flow rate capability) to gas of less than 0.1 millidarcy. The EPA also assumed the flowback lasted between 3 and 10 days for the average gas well, and 3 days for the average oil well. However, in response to a public comment on the 2015 NSPS OOOOa proposal claiming the definition of hydraulic fracturing was too broad, the EPA clarified it intended to “include operations that would increase the flow of hydrocarbons to the wellhead.” Similarly, in response to a public comment seeking an exemption for wells that have a flowback period of less than 24 hours, EPA acknowledged that there is a range of flowback periods, finding that the requested exemption was not warranted.

The Panel recommends that the EPA solicit comment on appropriate definitions for “tight formation” and “high rate, extended flowback” to clarify the proposal’s applicability.

Advocacy notes that the EPA's intent at the time of NSPS OOOO and NSPS OOOOa is not clearly stated to include conventional and unconventional reservoirs, particularly since the definition of "hydraulic fracturing" explicitly includes reference to the geologic features themselves, i.e. "tight formations," and to the operational activities that are absent in conventional reservoirs, "high rate, extended flowback." This aligns with the EPA's decision in the NSPS OOOO RIA to only analyze hydraulic fracturing in such "tight formations." Nor is the EPA's response to a comment about "operations that would increase the flow of hydrocarbons to the wellhead" a clearly stated intent to cover geologic features other than those explicitly described in the proposed definition. Advocacy therefore recommends that the EPA propose definitions with numerical standards that give meaning to the entire regulatory definition of "hydraulic fracturing," based on the SERs' characterization of the distinction between geological formations and operational characteristics likely to be the source of significant methane emissions.

4.3.8.2 Fugitive Emissions Requirements

Monitoring Frequency: For NSPS OOOOa, the EPA is evaluating revisions to resolve discrepancies between the 2020 Technical Rule and the 2016 NSPS OOOOa, unchanged by the 2020 Policy Rule. This includes aligning VOC and methane monitoring frequencies. SERs recommend the EPA adopt the VOC monitoring and associated reporting and recordkeeping provisions from the 2020 Technical Rule and apply those to methane. Advocacy recommends that the EPA propose aligning the monitoring frequency in NSPS OOOOa with the revised provisions for VOCs in the 2020 Technical Rule. The EPA recommends that it reanalyze the best system of emissions reduction for both pollutants, acknowledging that what was found to not be cost-effective for VOC in the 2020 Technical Rule may change when accounting for emissions reductions of both VOC and methane.

Low Production Well Sites: SERs provided several recommendations for low production well sites, ranging from completely exempting these well sites, requiring a maximum of annual monitoring, or providing an offramp as wells reach low production status. SERs contended that low production well sites have little to no emissions, and the EPA should delay proposing requirements until results of a DOE study on emissions from these sites is available. SERs recommended that the EPA focus its proposed requirements on ‘super emitters’ or ‘fat-tail’ emissions. SERs also recommended that the EPA revise its definition of low production well sites to align with the IRS definition of a stripper well property.

The Panel recommends the EPA propose fugitive emissions requirements that target sources with large emissions or super emitters. The EPA and Advocacy recommend that such a proposal impose fewer requirements on sources that are less likely to emit methane and/or have demonstrated a history of insignificant emissions. Advocacy and the EPA recommend that, if the EPA proposes annual screening requirements, these requirements contain clear thresholds for follow-up monitoring, including a de minimis level that warrants no further action. Advocacy further recommends that the EPA solicit comment on regulatory alternatives to minimize the number of well sites subject to monitoring, particularly at well sites that emit insignificant amounts of methane. The EPA recommends that it solicit comment on regulatory alternatives that prioritize monitoring on well sites that emit significant amounts of methane.

The Panel further recommends that the EPA solicit comment on regulatory alternatives for low production well sites. The EPA and Advocacy note that such a solicitation should include a range of options, including exempting these sites and providing an offramp for well sites that later become low production well sites, such as the EPA has proposed in the past. The Panel recommends that the EPA solicit comment on the factors that could make certain well sites less likely to emit methane, including geologic features, equipment onsite, production levels, and any other factors that could establish the basis for an exemption or off-ramp. The Panel further recommends that the EPA solicit comment for additional data, such as the DOE study, that assess the emissions from low production well sites and subsequently use this data to evaluate how monitoring requirements can be tailored to address sources mostly likely to be the sources of largest emissions and, if warranted, subcategorize sources unlikely to emit significant amounts of methane.

Regarding the definition of low production well site, the EPA contends that aligning its NSPS definition with the IRS definition is inappropriate. The IRS averages production over a calendar year of production, while the EPA averages production over the first 30 days of production after drilling or hydraulic fracturing. In the case where low production well sites have different requirements from other well sites, the affected facility would need to determine which set of requirements to follow and waiting for a full year of production data would be infeasible. Advocacy recommends that the EPA solicit comment on the use of the IRS definition of low production well sites following the initial production period.

Exemptions: In addition, SERs supported maintaining the NSPS OOOOa wellhead only exemption from fugitive emissions requirement and include this same exemption in the NSPS OOOOb proposal. This provision in NSPS OOOOa excludes from fugitive emissions monitoring a well site that is or later becomes a wellhead only well site, which the 2020 Technical Rule defines as “a well site that contains one or more wellheads and no major production and processing equipment.” The EPA and Advocacy agree that the EPA should maintain the wellhead only exemption from fugitive emissions requirements in NSPS OOOOa and propose a similar provision in the proposal for NSPS OOOOb.

Monitoring Technology: SERs recommended that the EPA allow audio, visual, and olfactory (AVO) and soap bubble tests as an option for finding fugitive emissions, particularly because they are lost cost and easy to implement alternatives for detecting leaks. The EPA clarified that soap bubble tests are a permissible option as part of Method 21. The Panel recommends that the EPA continue to allow Method 21 as an option for fugitive emissions monitoring. The Panel recommends that the EPA engage in additional outreach to small entities to ensure that there is an adequate understanding of the requirements and flexibilities that are already part of Method 21.

NSPS OOOOa allows AVO in limited and appropriate circumstances, including the inspection of cover and closed vent systems, but EPA believes AVO is inappropriate as the primary method for fugitive emissions inspections of well sites and compressor stations. The EPA recommends maintaining AVO inspections in these limited circumstances in NSPS OOOOb. Advocacy recommends the EPA propose allowing AVO as an alternative in limited circumstances, such as part of an off-ramp for facilities unlikely to emit more than insignificant methane or with a demonstrated history of insignificant emissions.

Alternative Technology: SERs supported the use of aerial, satellite, and other forms of monitoring for fugitive emissions requirements beyond traditional LDAR, but only as an alternative and not as an additional requirement. The Panel recommends that the EPA consider the cost and scope of alternative technologies and propose alternative screening technology. The EPA and Advocacy support proposing alternative screening technology as a compliance option rather than an additional regulatory requirement. The Panel further recommends that the EPA try to minimize significant additional reporting and recordkeeping requirements. The EPA and Advocacy recommend proposing emissions thresholds for alternative screening technology that would allow small businesses to adopt any alternative compliance options without significant additional reporting or recordkeeping requirements and without needing to seek prior approval or changes to Clean Air Act permits.

4.3.8.3 Pneumatic Controller Requirements

SERs stated that zero emission controllers are not feasible at wells sites or other locations without reliable electricity, and installing gas-fired compressors to provide sufficient air for instrument air systems may defeat the purpose by ultimately increasing emissions, and the installation of electric service would be extremely expensive.

The EPA and Advocacy recommend that the EPA only propose zero emission controllers at sites with reliable and consistent onsite power available and clearly state that the intent is not require the installation of electric services for this purpose.

4.3.8.4 Liquids Unloading Requirements

Some SERs questioned whether the EPA could regulate liquids unloading because best practices are very ‘site-specific.’ To the extent that the EPA includes liquid unloading requirements in the proposed NSPS OOOOb, SERs recommended that the EPA limit the requirements to best management practices. SERs stated that liquids unloading can take many forms, from simply blowing a gas well down to a tank bailing an open hole to swabbing a cased hole to various types of artificial lift. A SER identified a source for an industry best practices to which the EPA should align its requirements.

Advocacy recommends that the EPA not propose liquids unloading requirements. Advocacy is concerned that a best management practice written into a regulation, particularly one that is very ‘site-specific,’ will not provide small entities clear instructions and lead to confusion and significant risk of unwarranted enforcement actions. In addition, Advocacy is concerned that the EPA did not present the Panel or SERs more specific information about the need to regulate liquids unloading or likely costs. Should the EPA propose liquids unloading requirements, Advocacy recommends that the EPA only propose best management practices during liquids unloading operations that align with industry best practices and give operators clear discretion to manage on-site operations to minimize venting and ensure operational safety. Further, Advocacy recommends that the proposal explicitly recognize the wide range of legitimate and allowable practices during liquids unloading that may result in some emissions. Advocacy recommends the EPA require only limited recordkeeping associated with any liquids unloading operation and not require any reporting.

The EPA recommends that the NSPS OOOOb proposal include a robust set of best management practices during liquids unloading operations to minimize venting. The industry best practices provided by a SER allow exemptions for multiple types of liquids unloading operations, including swabbing and the use of plunger lifts, and suggest only monitoring the manual unloading process and closing wellhead vents to the atmosphere as soon as practicable. The EPA believes that the industry best practices are not sufficient to minimize venting from liquids unloading operations, and in particular, the number of exemptions would allow a significant portion of this emissions source to go unregulated.

The Panel recommends that the EPA solicit comments on exemptions for operations that may be unlikely to result in emissions, such as wellheads that are not operating under positive pressure.

4.3.8.5 Storage Vessels

SERs discussed concerns with the current regulatory approach towards storage vessels. First, SERs recommended establishing a regulatory off-ramp based on interconnected tanks that are operated as a single unit but currently regulated as multiple sources. The EPA and Advocacy recommend that EPA propose that NSPS OOOOb applies to tank batteries rather than single storage vessels. The EPA and Advocacy agree that the EPA propose an off-ramp for tank batteries with emissions that later fall below a certain threshold of VOC and methane emissions.

Second, SERs raised concerns that situations exist where propane or other fossil fuel must be used to maintain continuous pilot lights for flares that serve as control devices on storage tanks that do not produce enough emissions. The Panel agrees that this issue deserves greater study, including whether the GHG benefits of these control devices are negated by the need to burn additional fossil fuels and whether additional factors exist that may cause variability in emissions from storage tanks or could be used to more narrowly target these requirements to limit the unnecessary operation of flares. The Panel recommends that the EPA request comment on this issue.

One SER identified a conflict with a lease requirement for BLM leases in Michigan requiring operators to open the tank hatches daily to check oil levels, for the purposes of royalty calculation and loss prevention. This requirement however negates the emissions benefit of any emissions limitation. Advocacy recommends the EPA request more information about this situation from BLM, including consultations with BLM. If this requirement exists in Federal, State or tribal leases, then the EPA should propose an exemption for affected storage tanks. The EPA consulted with BLM on this issue and found that BLM requires tank gauging monthly and this does not require opening the thief hatch. The Panel recommends that TEPA continue to consult with BLM on its oil and gas regulations to ensure the regulations are harmonized, good government practice, and that owners and operators have clarity on compliance requirements if they are subject to both BLM and EPA regulations.

4.3.8.6 Compressors

A SER expressed opposition to changing rod packing requirements from a fixed timeline to a performance standard based on flow measurement. Advocacy notes that this consistent with small business concerns that compliance with performance standards are often more expensive because of the monitoring and recordkeeping. Small businesses frequently prefer design standards that are explicit in their requirements and do not require additional monitoring.

Advocacy recommends that, if the EPA proposes a rod packing requirement based on flow measurement or other performance standard, the EPA should propose an alternative compliance strategy based on time in service or hours of operation. The EPA believes that the flow measurement is a straightforward and low cost compliance strategy. The EPA recommends maintaining the alternative compliance strategy of routing reciprocating compressor emissions to a process.

SERs expressed opposition to the EPA's suggested definition of a 'centralized production facility' a specific type of well site that operates with a larger number and size of equipment than individual well sites. One SER stated that Colorado's definition of this type of facility was inappropriate because it would inadvertently capture all well sites with a single well head and a compressor.

The EPA and Advocacy agree that, if EPA proposes to regulate compressors at centralized production facilities, the definition of these facilities should clearly exclude single well head sites with small compressors.

4.3.8.7 Requirements for Certification by Professional Engineers

SERs addressed aspects of NSPS OOOOa that require a professional engineer (PE) certification. SERs argued that this requirement did not recognize the significant industry-specific experience available in-house at many firms and thus unnecessarily raised costs for small businesses. They recommended relaxing the requirement to allow engineering certifications "to include those with a mathematical, geological and other related educational disciplines combined with a fixed amount of experience in the design, operations, construction and maintenance of oil and natural gas facilities." In the 2020 Technical Rule, the EPA expands the NSPS OOOOa requirements to allow either a PE or an in-house engineer to complete these certifications. Advocacy and the EPA recommend that the EPA maintain the flexibility for in-house engineers to complete these certifications in NSPS OOOOa and include this same flexibility in NSPS OOOOb.

4.4 Employment Impacts of Environmental Regulation

This section presents an overview of the various ways that environmental regulation can affect employment.[75] Employment impacts of environmental regulations are generally composed of a mix of potential declines and gains in different areas of the economy over time. Regulatory employment impacts can vary across occupations, regions, and industries; by labor and product demand and supply elasticities; and in response to other labor market conditions. Isolating such impacts is a challenge, as they are difficult to disentangle from employment impacts caused by a

[75] Additionally, see Section 4.2.5 for a discussion of the demographic characteristics of oil and natural gas workers and communities.

wide variety of ongoing, concurrent economic changes. The EPA continues to explore the relevant theoretical and empirical literature and to seek public comments in order to ensure that the way the EPA characterizes the employment effects of its regulations is reasonable and informative.

Environmental regulation "typically affects the distribution of employment among industries rather than the general employment level" (Arrow et al., 1996). Even if impacts are small after long-run market adjustments to full employment, many regulatory actions have transitional effects in the short run (OMB, 2015). These movements of workers in and out of jobs in response to environmental regulation are potentially important and of interest to policymakers. Transitional job losses have consequences for workers that operate in declining industries or occupations, have limited capacity to migrate, or live in communities or regions with high unemployment rates.

As indicated by the potential impacts on oil and natural gas markets discussed in Section 4.1, the proposed NSPS OOOOb and EG OOOOc are projected to cause small changes in oil and natural gas production and prices. As a result, demand for labor employed in oil and natural gas-related activities and associated industries might experience adjustments as there may be increases in compliance-related labor requirements as well as changes in employment due to quantity effects in directly regulated sectors and sectors that consume oil and natural gas products.

5 COMPARISON OF BENEFITS AND COSTS

5.1 Comparison of Benefits and Costs

A comparison of benefits and costs is presented below. All estimates are in 2019 dollars. Also, all compliance costs, emissions changes, and benefits are estimated for the years 2022 to 2035 relative to a baseline without the proposed NSPS OOOOb and EG OOOOc.

Table 5-1 summarizes the emissions reductions associated with the proposed standards over the 2023 to 2035 period for the NSPS OOOOb, the EG OOOOc, and the NSPS OOOOb and EG OOOOc combined. Table 5-2, Table 5-3, and Table 5-4 present the present value (PV) and equivalent annual value (EAV), estimated using discount rates of 3 and 7 percent, of the changes in quantified benefits, costs, and net benefits, as well as the emissions reductions relative to the baseline for the proposed NSPS OOOOb, for the proposed EG OOOOc, and the proposed NSPS OOOOb and EG OOOOc, respectively. These values reflect an analytical time horizon of 2023 to 2035, are discounted to 2021, and presented in 2019 dollars. These tables include consideration of the non-monetized benefits associated with the emissions reductions projected under this proposal.

Table 5-1 Projected Emissions Reductions under the Proposed NSPS OOOOb and EG OOOOc across Regulatory Options, 2023–2035

		Emissions Changes			
Regulatory Option	**Proposed Requirements**	**Methane (millions short tons)**	**VOC (millions short tons)**	**HAP (millions short tons)**	**Methane (million metric tons CO_2 Eq. using GWP=25)**
Less Stringent Option					
	NSPS OOOOb	1.1	0.4	0.02	24
	EG OOOOc	25	7.6	0.3	560
	Total	**26**	**8.0**	**0.3**	**590**
Co-proposal					
	NSPS OOOOb	5.8	1.7	0.06	130
	EG OOOOc	33	9.9	0.40	760
	Total	**39**	**12**	**0.46**	**890**
Primary Proposal					
	NSPS OOOOb	6.1	1.8	0.07	140
	EG OOOOc	35	10.0	0.41	790
	Total	**41**	**12**	**0.48**	**920**
More Stringent Option					
	NSPS OOOOb	6.5	1.9	0.07	150
	EG OOOOc	37	11	0.44	840
	Total	**43**	**13**	**0.51**	**990**

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

Table 5-2 Projected Benefits, Compliance Costs, and Emissions Reductions across Regulatory Options under the Proposed NSPS OOOOb, 2023–2035 (million 2019$)[a]

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[b]				
Less Stringent	$1,400	$140	$1,400	$140
Co-Proposal	$7,900	$740	$7,900	$740
Primary Proposal	$8,300	$780	$8,300	$780
More Stringent	$8,800	$830	$8,800	$830
	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Net Compliance Costs				
Less Stringent	$170	$16	$140	$16
Co-Proposal	($330)	($31)	($44)	($5.2)
Primary Proposal	($160)	($15)	$75	$8.9
More Stringent	$670	$63	$670	$80
Compliance Costs				
Less Stringent	$270	$26	$210	$25
Co-Proposal	$470	$44	$520	$62
Primary Proposal	$670	$63	$660	$79
More Stringent	$1,600	$150	$1,300	$160
Value of Product Recovery				
Less Stringent	$100	$10	$72	$9
Co-Proposal	$800	$75	$560	$67
Primary Proposal	$840	$79	$590	$70
More Stringent	$900	$84	$630	$76
Net Benefits				
Less Stringent	$1,300	$120	$1,300	$120
Co-Proposal	$8,200	$780	$8,000	$750
Primary Proposal	$8,400	$790	$8,200	$770
More Stringent	$8,200	$770	$8,200	$750
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent		1,100,000		
Co-Proposal		5,800,000		
Primary Proposal		6,100,000		
More Stringent		6,500,000		

$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons)[c]:	
Less Stringent	420,000
Co-Proposal	1,700,000
Primary Proposal	1,800,000
More Stringent	1,900,000
HAP benefits from reducing HAP emissions by (in short tons):	
Less Stringent	16,000
Co-Proposal	64,000
Primary Proposal	67,000
More Stringent	71,000
Visibility benefits	
Reduced vegetation effects	

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane (SC-CH_4) (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-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; see Table 3-8 for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. All net benefits are calculated using climate benefits discounted at 3 percent.
[c] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix B.

Table 5-3 Projected Benefits, Compliance Costs, and Emissions Reductions across Regulatory Options under the Proposed EG OOOOc, 2023–2035 (million 2019$)[a]

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[b]				
Less Stringent	$34,000	$3,200	$34,000	$3,200
Co-Proposal	$45,000	$4,300	$45,000	$4,300
Primary Proposal	$47,000	$4,400	$47,000	$4,400
More Stringent	$50,000	$4,700	$50,000	$4,700
	3 Percent Discount Rate		**7 Percent Discount Rate**	
	PV	EAV	PV	EAV
Net Compliance Costs				
Less Stringent	$7,200	$670	$5,500	$660
Co-Proposal	$6,500	$610	$5,600	$670
Primary Proposal	$7,400	$690	$6,300	$750
More Stringent	$11,000	$1,100	$9,200	$1,100
Compliance Costs				
Less Stringent	$10,000	$980	$7,900	$940
Co-Proposal	$11,000	$1,000	$8,800	$1,100
Primary Proposal	$12,000	$1,100	$9,600	$1,100
More Stringent	$17,000	$1,600	$13,000	$1,500
Value of Product Recovery				
Less Stringent	$3,300	$310	$2,300	$280
Co-Proposal	$4,500	$420	$3,200	$380
Primary Proposal	$4,700	$440	$3,300	$400
More Stringent	$5,000	$470	$3,600	$430
Net Benefits				
Less Stringent	$27,000	$2,500	$28,000	$2,500
Co-Proposal	$39,000	$3,700	$40,000	$3,600
Primary Proposal	$40,000	$3,700	$41,000	$3,700
More Stringent	$39,000	$3,700	$41,000	$3,600
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent		25,000,000		
Co-Proposal		33,000,000		
Primary Proposal		35,000,000		
More Stringent		37,000,000		

$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons):	
Less Stringent	7,600,000
Co-Proposal	9,900,000
Primary Proposal	10,000,000
More Stringent	11,000,000
HAP benefits from reducing HAP emissions by (in short tons):	
Less Stringent	310,000
Co-Proposal	400,000
Primary Proposal	410,000
More Stringent	440,000
Visibility benefits	
Reduced vegetation effects	

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane (SC-CH_4) (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-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; see Table 3-9 for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. All net benefits are calculated using climate benefits discounted at 3 percent.

Table 5-4 Projected Benefits, Compliance Costs, and Emissions Reductions across Regulatory Options under the Proposed NSPS OOOOb and EG OOOOc, 2023–2035 (million 2019$)[a]

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[b]				
Less Stringent	$35,000	$3,300	$35,000	$3,300
Co-Proposal	$53,000	$5,000	$53,000	$5,000
Primary Proposal	$55,000	$5,200	$55,000	$5,200
More Stringent	$59,000	$5,600	$59,000	$5,600
	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Net Compliance Costs				
Less Stringent	$7,300	$690	$5,700	$680
Co-Proposal	$6,200	$580	$5,600	$670
Primary Proposal	$7,200	$680	$6,300	$760
More Stringent	$12,000	$1,100	$9,900	$1,200
Compliance Costs				
Less Stringent	$11,000	$1,000	$8,100	$970
Co-Proposal	$11,000	$1,100	$9,400	$1,100
Primary Proposal	$13,000	$1,200	$10,000	$1,200
More Stringent	$18,000	$1,700	$14,000	$1,700
Value of Product Recovery				
Less Stringent	$3,400	$320	$2,400	$290
Co-Proposal	$5,300	$500	$3,800	$450
Primary Proposal	$5,500	$520	$3,900	$470
More Stringent	$5,900	$560	$4,200	$500
Net Benefits				
Less Stringent	$28,000	$2,600	$30,000	$2,600
Co-Proposal	$47,000	$4,400	$48,000	$4,300
Primary Proposal	$48,000	$4,500	$49,000	$4,500
More Stringent	$47,000	$4,400	$49,000	$4,400
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent	26,000,000			
Co-Proposal	39,000,000			
Primary Proposal	41,000,000			
More Stringent	43,000,000			

$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons):	
Less Stringent	8,000,000
Co-Proposal	12,000,000
Primary Proposal	12,000,000
More Stringent	13,000,000
HAP benefits from reducing HAP emissions by (in short tons):	
Less Stringent	330,000
Co-Proposal	460,000
Primary Proposal	480,000
More Stringent	510,000
Visibility benefits	
Reduced vegetation effects	

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane (SC-CH_4) (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-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; see Table 3-7 for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. All net benefits are calculated using climate benefits discounted at 3 percent.

5.2 Uncertainties and Limitations

Throughout the RIA, we considered several sources of uncertainty, both quantitatively and qualitatively, regarding the emissions reductions, benefits, and costs estimated for the proposed rule. We summarize the key elements of our discussions of uncertainty below.

Source-level compliance costs and emissions impacts: As discussed in Section 2-2, the first step in the compliance cost analysis is the development of per-facility national-average representative costs and emissions impacts using a model plant approach. The model plants are designed based upon the best information available to the Agency at the time of the rulemaking. By emphasizing facility averages, geographic variability and heterogeneity across producers in the industry is masked, and regulatory impacts at the facility-level may vary from the model plant averages.

There may also be an opportunity cost associated with the installation of environmental controls (for purposes of mitigating the emissions of pollutants) that is not reflected in the control costs. In the event that investment in environmental compliance displaces other investment in productive capital, the difference between the rate of return on the investment displaced by the mandatory environmental investment is a measure of the opportunity cost of the environmental requirement. To the extent that such opportunity costs of capital are not accounted for in the estimated compliance cost reductions, the cost reductions may be underestimated.

Projection methods and assumptions: As discussed in Section 2-2, the second component in estimating national impacts is the projection of affected facilities. Uncertainties in the projections informing this RIA results include: 1) choice of projection method; 2) data sources and drivers; 3) limited information about rate of modification and turnover of sources; 4) behavioral responses to regulation; and 5) unforeseen changes in industry and economic shocks.

Years of analysis: The years of analysis are 2023, to represent the full first-year facilities are affected by this action, through 2035, to represent impacts of the rule over a longer period, as discussed in Section 2-2. While it would be desirable to analyze impacts beyond 2035 in this RIA, the EPA has chosen not to do this largely because of the limited information available on the turnover rate of emissions sources and controls. Extending the analysis beyond 2035 would introduce substantial and increasing uncertainties in the projected impacts of the proposal.

Treatment of sources in Alaska: The RIA does not account for instances in which all or some sources in Alaska are subject to different proposed requirements than those in the rest of the country, both in the baseline due to previous rulemakings and in the proposal. For example, the 2018 amendments to the 2016 NSPS OOOOa ("Alaska Amendments") reduced fugitives monitoring frequency requirements for well sites and compressor stations on the Alaska North Slope.[76] We do not reflect those reduced requirements in the baseline in this RIA, nor do we reflect that the same reduced requirements are being proposed for the NSPS OOOOb and EG OOOOc. In addition, for sites in Alaska, the NSPS OOOOb and EG OOOOc only requires non-emitting pneumatic controllers to be installed at sites where onsite power is available; otherwise, the requirement is to replace high-bleed controllers with low-bleed controllers. In both cases, these omissions suggest that our analysis may overestimate the impacts of the proposed regulation.

State rules and voluntary action in the baseline: As discussed in Section 2.2.3, while we accounted for state regulations in California and Colorado in the baseline, there are many other state and local requirements that may be in the baseline that we are unable to account for. In addition, the baseline does not reflect voluntary actions firms may take to reduce emissions in the oil and natural gas sector. By not fully accounting for state and local requirements (outside of Colorado and California) and voluntary actions in the baseline, this analysis may overestimate the impacts of the proposed regulation.

Wellhead natural gas prices used to estimate revenues from natural gas recovery: The compliance cost estimates presented in this RIA include the estimates of the revenue associated with the increase in natural gas recovery resulting from compliance actions. As a result, the national compliance cost impacts depend on the price of natural gas. As explained in Section 2-4 natural gas prices used in this analysis are from the projection of the Henry Hub price in the AEO2021. To the extent actual natural gas prices diverge from the AEO projections, the actual impacts will diverge from our estimates.

[76] 83 FR 10628.

Oil and natural gas market impact analysis: The oil and natural gas market impact analysis presented in this RIA is subject to several caveats and limitations. As with any modeling exercise, the market impact analysis presented here depends crucially on uncertain input parameters and assumptions regarding market structure. A more detailed discussion of the caveats and limitations of the oil and natural gas market impacts analysis can be found in Section 4.1.5.

Monetized methane-related climate benefits: The EPA considered the uncertainty associated with the social cost of methane (SC-CH_4) estimates, which were used to calculate the social benefits of the decrease in methane emissions projected because of this action. The potential impacts of some uncertainties are accounted for in the analysis or discussed quantitatively, while other areas of uncertainty have not yet been quantified in a way that can be modeled. Section 3.2 provides a detailed discussion of the ways in which the modeling underlying the development of the SC-CH_4 estimates used in this analysis addresses quantified sources of uncertainty and presents a sensitivity analysis to show consideration of the uncertainty surrounding the choice of discount rate over long time horizons.

Monetized VOC-related ozone benefits: The illustrative screening analysis described in Illustrative Screening Analysis of Monetized VOC-Related Ozone Health Benefits includes many data sources as inputs that are each subject to uncertainty. Input parameters include projected emissions inventories, projected compliance methods, 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. Below are key uncertainties associated with estimating the number and value of ozone-related premature deaths.

The estimated number and value of avoided ozone-attributable deaths are 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 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 health impact function without a threshold in modeling both long- and 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 (U.S EPA, 2020a, Section 6.2.6). Thus, estimates include health benefits from reducing ozone in areas with concentrations of ozone down to the lowest modeled concentrations.

Our estimate of the total monetized ozone-attributable benefits is based on the 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; NRC, 2008). Since the publication of these reports, the EPA has continued improving its techniques for characterizing uncertainty in the estimated air pollution-attributable benefits. Where possible, we quantitatively assess uncertainty in each input parameter (for example, statistical uncertainty is characterized by performing Monte Carlo simulations). However, in some cases, this type of quantitative analysis is not possible due to lack of data, so we instead characterize the sensitivity of the results to alternative plausible input parameters. And, for some inputs into the benefits analysis, such as the air quality data, we lack the data to perform either a quantitative uncertainty analysis or sensitivity analysis. Additional detail regarding specific uncertainties associated with ozone health benefit estimates can be found 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* (U.S. EPA, 2021g, Section 6.2).

Non-monetized benefits: Several categories of health, welfare, and climate benefits are not quantified in this RIA. These unquantified benefits are described in detail in Section 3.

Environmental justice analyses: the EPA performed quantitative EJ assessments of baseline HAP cancer risks, ozone exposure and health risks, employment, and household energy expenditures. Each of these analyses are subject to various types of uncertainty related to input parameters and assumptions. Qualitatively, assessments that further subdivide the populations assess are subject to increased uncertainty as compared to overall exposure and risk estimates.

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APPENDIX A ADDITIONAL INFORMATION ON COST AND EMISSIONS ANALYSIS

A.1 Calculation of Bin Proportions and Average Baseline Emissions for Well Site Fugitives

To generate the proportions (and associated average baseline emissions estimates) of well sites in the three fugitive emissions bins, we use a Monte Carlo simulation algorithm. Separate distributions are simulated for all combinations along three dimensions: oil versus natural gas sites, pre-OOOO versus post-OOOO sites, and sites with or without zero-emitting pneumatic controllers, for a total of eight distributions. Each site-level fugitive emissions distribution is based on a series of random draws from four underlying distributions of site equipment/emissions, which are further characterized below. This process is intended to mimic the site-level baseline emissions calculations that producers would be expected to perform to determine monitoring requirements.

The four equipment distributions, as depicted in Figure A-1, are: (1) components associated with major equipment;[77] (2) continuous and intermittent bleed pneumatic controllers; (3) pneumatic pumps; and (4) storage vessels. Because emissions from controllers and storage vessels factor into the fugitive emissions calculation, there are interactions with other aspects of the proposed rule, as discussed below.

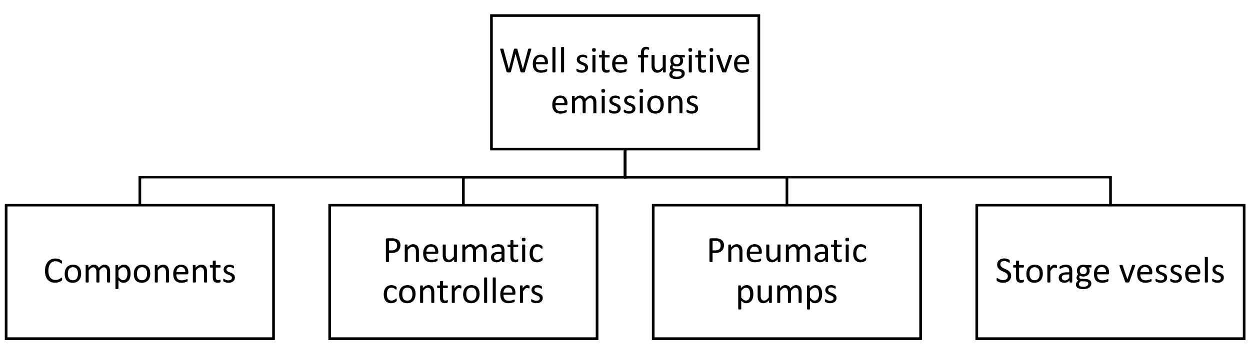

Figure A-1 Components of Well Site Fugitive Emissions

[77] Major equipment in this case refers to wellheads (both oil and natural gas), separators (both), meters/piping (natural gas), in-line heaters (natural gas), dehydrators (natural gas), headers (oil), and heater/treaters (oil). Components refer to valves, flanges (oil only), connectors, open-ended lines, and pressure relief valves.

The algorithm proceeds as follows:

1. Define the emissions distribution to be calculated, e.g., pre-OOOO, natural gas well sites with access to reliable electricity, and choose a (large) number (denote it *N*) of draws to calculate the distribution over.

2. Draw *N* times from the distribution of fugitive emissions from components. This distribution is constructed by combining EPA Protocol component emissions factors, default average component counts for major equipment from Tables W-1B and W-1C of the EPA Greenhouse Gas Reporting Program (GHGRP) petroleum and natural gas systems source category (40 CFR Part 98 subpart W, also referred to as GHGRP subpart W), and major equipment data for each site from a survey of well sites reported by API to generate an empirical distribution of total site-level fugitive emissions. We sample from the resulting empirical distribution of total fugitive emissions while adding small amounts of white noise for smoothing.To illustrate the process, suppose a gas well site draw is being made. First, one of the 2,183 gas well sites from the API survey is selected.[78] Each well site is associated with counts of major equipment: wellheads, separators, heater-treaters, headers, meters/piping, compressors, in-line heaters, and dehydrators. Using GHGRP subpart W factors,[79] major equipment is mapped to component counts, where components include valves, flanges, open-ended lines, pressure relief valves, connectors, and other components. Emissions at a well site are then calculated by multiplying the count of each component type for all major equipment by the emissions factors from the EPA Protocol and summing over component types.[80]

3. If the emissions distribution from step 1 is for sites with zero-emitting pneumatic controllers, set emissions from pneumatic controllers to zero; otherwise, draw *N* times from the distribution of pneumatic controllers. The shape of the distribution depends on

[78] See Attachment 4 (Microsoft Excel workbook) of Docket ID No. EPA-HQ-OAR-2017-0757-0002, *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API*. The dataset contains survey data on 2,183 gas well sites and 1,742 oil well sites.

[79] See Tables W-1B and W-1C of Subpart W – Petroleum and Natural Gas Systems, 40 C.F.R. Part 98, subpart W (2021).

[80] See Table 2-4 on page 2-15 of U.S. EPA (1995).

whether the site type is oil or natural gas. In both cases, the number of pneumatic controllers at a well site is assumed to follow a geometric distribution with support $\{0,1,2,\ldots\}$. We calibrate the distribution parameters for oil and natural gas sites such that the expected values equal the average number of pneumatic controllers per site in 2019 implied by the GHGI.[81] For a given draw, controllers are divided between low-bleed and intermittent bleed controllers in constant proportion according to the 2019 values from the GHGI.[82] To calculate the total fugitive emissions contribution from controllers, low- and intermittent bleed controller counts are weighted by their respective emissions factors and summed.[83]

4. Draw *N* times from the distribution of pneumatic pumps. Pneumatic pumps for both oil and natural gas sites are assumed to follow Bernoulli distributions, with distribution parameters equal to the number of pneumatic pumps from GHGI divided by the number of well sites from GHGI. For draws equal to one, the emissions factor for pumps is applied.[84]

5. Draw *N* times from the distribution of storage vessel (tank battery) emissions. Based on the BSER analysis for storage vessels,[85] we assign the tank battery for each site to one of four model tank batteries (denoted E, F, G, and H) based on the empirical distribution from the 1992 (for natural gas) or 2006 (oil) base year data. Once the model tank battery has been drawn, we assign it to one of ten emissions values based on a uniform distribution, consistent with the BSER analysis. For example, model tank battery E may emit from 0.2, 0.4, 0.5, 0.6, 0.9, 1.1, 2.1, 3.2, 14.1, or 19.7 tons of CH_4 per year; model E tank batteries are assigned one of those values based on a uniform random draw. If the emissions distribution for step 1 is for pre-OOOO sites, we apply a 95 percent reduction

[81] To calculate the average number of pneumatic controllers per site, first we sum, for oil and natural gas sites separately, the total of low, intermittent, and high bleed controllers and divide by the number of wells using the 2019 count data from the GHGI. We then multiply by an estimated national average number of wells per site, calculated using the Enverus data, and divide by 0.73 to account for our assumption that 27 percent of sites are wellhead only and therefore do not have controllers on site.

[82] While some sites may still have high-bleed controllers in the baseline, they represent a small fraction (less than 2 percent in the GHGI for 2019) of the total number of controllers at well sites. To simplify the analysis, we assume all controllers are either low or intermittent bleed when constructing the fugitive emissions bins.

[83] See Tables W-1A of Subpart W – Petroleum and Natural Gas Systems, 40 C.F.R. Part 98, subpart W (2021).

[84] Ibid.

[85] See Chapter 6 of the 2021 TSD for details.

to tank battery emissions if those emissions exceed 20 tons per year of methane and no reduction otherwise, consistent with the proposed rule. If the emissions distribution is for post-OOOO sites, we apply a 95 percent reduction to tank battery emissions if those emissions exceed 6 tons per year of VOC and no reduction otherwise.

6. Sum the resulting emissions from steps 2–5 for each of the *N* draws.

7. Group the draws into the each of the three fugitive emissions bins and calculate the proportion of draws and the average emissions within each bin.

8. Repeat steps 1–7 for the remaining fugitive emissions distributions until all eight have been characterized.

We use the results of the Monte Carlo simulations to apportion the well site activity data into fugitive emissions bins, holding fixed the proportions and average emissions rates for all projected years. Due to limited data, there are several key assumptions that merit illumination.

- **Independence across site equipment/emissions distributions.** We assume there is no correlation between, e.g., the number of components at a site and the number of pneumatic controllers.

- **No distinction in site equipment/emissions distributions across site vintages and locations.** The only distinction we make across site vintages is whether they are subject to the NSPS VOC requirements or the EG methane requirements. However, more recently completed well sites tend to be larger (more wells per site) and therefore likely have more equipment on site. In addition, average well site characteristics differ across locations.

- **Component count data may not be representative.** Related to the point above, the API well site survey data used to generate the component emissions distribution is likely biased toward newer well sites.

- **Assumed parametric distributions for pneumatic controllers and pneumatic pumps.** Given a lack of data, we made simplifying assumptions on the distributions for pneumatic controllers and pumps to reduce the number of moments needed to fit them. Additional data would be needed to characterize those distributions more accurately.

- **No variation in proportions of intermittent/low-bleed controllers.** We assume a fixed proportion of intermittent and low-bleed pneumatic controllers for each well site draw. A more accurate representation would also characterize the distribution of that proportion.

A.2 Calculation of Costs for Initial Regulatory Flexibility Analysis

The Initial Regulatory Flexibility Analysis (IRFA) contains calculations of cost-to-sales ratios (CSRs) for small entities affected by the proposed NSPS OOOOa While the EPA has data from Enverus and EIA on what entities completed NSPS-affected wells during 2019 and operated processing facilities as of 2017 (as described in Section 2.2), this data does not identify what equipment is present at each facility and cannot be used to estimate exact costs. This section describes the process used to estimate costs at affected facilities and construct CSRs for affected entities identified in the Enverus data. The process varies based on the type of facility (well site vs processing plant). Total annualized costs are estimated for each facility type and then aggregated over affected entities.

A.2.1 Estimation of Costs for Well Sites

The following information is needed to determine cost increases at a well site relative to baseline: the methane emissions bin (0–3 tpy, 3–8 tpy, or 8+ tpy); the number of pneumatic controllers present at the well site; the number and type of storage vessels present at a well site; and the number of liquids unloading events occuring at a well site. The process for assigning costs to well sites is as follows:

1. The well site is assigned to a methane emissions bin (0–3 tpy, 3–8 tpy, or 8+ tpy). To assign a methane emissions bin, EPA samples from the same emissions distribution used to construct bin proportions and average baseline emissions for wellsite fugitive (see Section 7.1 for a description of the process). The well site is assigned the cost for an NSPS-affected model well site in the associated methane emissions bin. Sampling from the emissions distribution also produces an estimated count of pneumatic controllers, whether a site has on-site power available, and the model storage vessel present at a well site. Finally, a well site has a 27 percent probability of being a wellhead-only site (an

assumption used throughout this RIA). If a site is categorized as wellhead-only, steps 2–4 are skipped and well site cost is set to 0.

2. The cost associated with pneumatic controllers is calculated. First, a site is randomly assigned to electronic or solar compliance based on the assumed probabilities a site falls into each category. Then, each site is assigned the cost of the most costly-to-control model pneumatic controller in it's compliance category multiplied by the number of controllers at the well site (determined in step 1).

3. The control cost associated with the model storage vessel sampled in step 1 is assigned to the well site. It is assumed that each well site contains one storage vessel (tank battery).

4. To calculate the number of liquids unloading events at each well site, the number of projected NSPS-affected liquids unloading events in 2023 is divided by the projected number of NSPS-affected well sites in 2023. This gives an average number of liquids unloading events per well site. This average number is multiplied by the average cost of control for a liquids unloading event and assigned to the well site.

Steps 1–4 are repeated many times for each well site to calculate an average total annualized cost at each well site.

A.2.2 Estimation of Costs for Natural Gas Processing Plants

The following information is needed to determine costs at a natural gas processing plant: the size of the plant and the number of reciprocating compressors at the plant. Since the size of a processing plant and the number of reciprocating compressors is not available, each must be estimated. The process proceeds as follows.

1. A processing plant is determined to be large or small based on the proportion of projected NSPS-affected facilities falling into each category in 2023. That is, the probability that a plant is large is equal to the proportion of NSPS-affected natural gas processing plants that are large in 2023. A plant is assigned control cost for the model natural gas processing plant of the appropriate size.

2. To calculate the number of reciprocating compressors at each processing plant, the number of projected NSPS-affected reciprocating compressors in 2023 is divided by the projected number of NSPS-affected processing plants in 2023. This gives an average number of reciprocating compressors per processing plant. This average number is multiplied by the average cost of control for the most costly-to-control model reciprocating compressor and assigned to the processing plant.

Steps 1–2 are repeated many times for each processing plant to calculate an average total annualized cost at each site.

A.2.3 Estimating Aggregate Costs for Each Affected Entity

Once an average total annualized cost is estimated for each well site and processing plant, costs for each affected facility are summed over affected entities and segment to calculate a total annualized cost for each affected entity. These costs are used to calculate the cost-to-sales ratios by segment that are presented in Section 4.3.4.

A.3 References

U.S. Environmental Protection Agency (U.S. EPA). 1995. *Protocol for Equipment Leak Emission Estimates*. U.S. Environmental Protection Agency. Research Triangle Park, NC. Office of Air Quality Planning and Standards. EPA-453/R-95-017. Available at: https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf.

APPENDIX B ILLUSTRATIVE SCREENING ANALYSIS OF MONETIZED VOC-RELATED OZONE HEALTH BENEFITS

In this appendix, we present a supplementary screening analysis to estimate potential health benefits from the changes in ozone concentrations resulting from VOC emissions reductions under the proposed rule. As we describe in detail below, the distribution of the change in VOC emissions are subject to significant uncertainties; for this reason, the estimated benefits reported below should not be interpreted as a central estimate and thus are not reflected in the calculated net benefits above. For this analysis, we apply a national benefit-per-ton approach based on photochemical modeling with source apportionment paired with the Environmental Benefits Mapping and Analysis Program (BenMAP) for years between 2023 and 2035 using an April-September average of 8-hr daily maximum (MDA8) ozone metric.

B.1 Air Quality Modeling Simulations

The photochemical model simulations are described in detail in U.S. EPA (2021a) and are summarized briefly in this section. The air quality modeling used in this analysis included annual model simulations for the year 2017. The photochemical modeling results for 2017, in conjunction with modeling to characterize the air quality impacts from groups of emissions sources (i.e., source apportionment modeling) and expected emissions changes due to this proposed rule, were used to estimate ozone benefits expected from this proposed rule in the years 2023–2035.

The air quality model simulations (i.e., model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx version 7.00) (Ramboll Environ, 2016). The 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 B-2.

Figure B-2 Air Quality Modeling Domain

B.1.1 Ozone Model Performance

While U.S. EPA (2021) provides an overview of model performance, we provide a more detailed assessment here specifically focusing on ozone model performance relevant to the metrics used in this analysis. In this section we report CAMx model performance for the MDA8 ozone across all days in April-September. While regulatory analyses often focus on model performance on high ozone days relevant to the NAAQS (U.S. EPA, 2018), here we focus on all days in April-September since the relevant ozone metrics used as inputs into BenMAP use summertime seasonal averages. Model performance information is provided for each of the nine National Oceanic and Atmospheric Administration (NOAA) climate regions in the contiguous US, as shown in Figure B-3 and first described by Karl and Coss (1984).

Table B-1 provides a summary of model performance statistics by region. Normalized Mean Bias was within ±10 percent in every region and within ±5 percent in the Northeast, Ohio Valley, South, Southwest, and West regions. Across all monitoring sites, normalized mean bias was -0.2 percent. Normalized mean error for modeled MDA8 ozone was less than ±20 percent in every region except the Northwest where it was 21 percent. Correlation between the modeled and observed MDA8 ozone values was 0.7 or greater in five of the nine regions (Northeast, Upper Midwest, Southeast, South, and West). In the remaining four regions correlation was 0.69 in the Ohio Valley, 0.64 in the Northern Rockies and Plains, 0.46 in the Southwest, and 0.69 in the

Northwest. Across the contiguous U.S. as a whole, the correlation between modeled and measured MDA8 ozone was 0.72.

Figure B-4 displays modeled MDA8 normalized mean bias at individual monitoring sites. This figure reveals that the model has slight overpredictions of mean April-September MDA8 ozone in the southeastern portion of the country and along the Pacific coast and slight underpredictions in the northern and western portions of the country. Time series plots of the modeled and observed MDA8 ozone and model performance statistics across the nine regions were developed.[86] Overall, the model closely captures day to day fluctuations in ozone concentrations, although the model had a tendency to underpredict ozone in the earlier portion of the ozone season (April and May) and overpredict in the later portion of the ozone season (July-September) with mixed results in June. This model performance is within the range of other ozone model applications, as reported in scientific studies (Simon et al., 2012, Emery et al., 2017). Thus, the model performance results demonstrate the scientific credibility of our 2017 modeling platform. These results provide confidence in the ability of the modeling platform to provide a reasonable projection of expected future year ozone concentrations and contributions.

[86] Memorandum. *2017 Time Series Plots Supporting the Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*. Prepared by Heather Simon, AQAD/OAQPS/EPA. September 29, 2021.

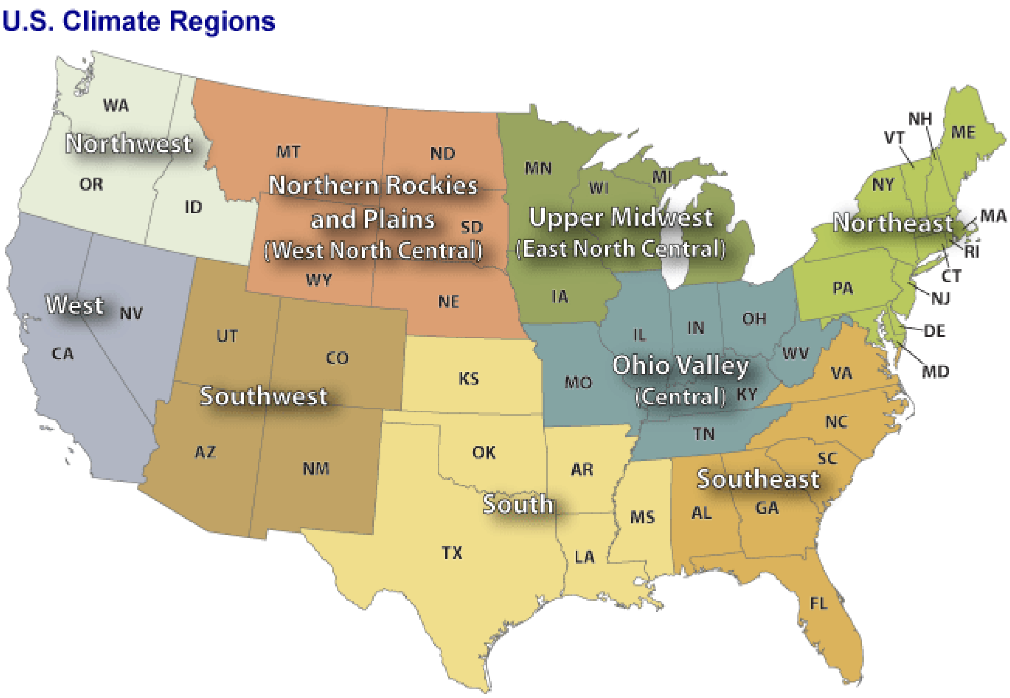

Figure B-3 Climate Regions Used to Summarize 2017 CAMx Model Performance for Ozone (from https://www.ncdc.noaa.gov/monitoring-references/maps/us-climate-regions.php)

Table B-1 Summary of 2017 CAMx MDA8 ozone model performance for all April–September days

Region	Number of Monitoring Sites	Mean observed MDA8 (ppb)	Mean modeled MDA8 (ppb)	Correlation	Mean bias (ppb)	RMS E (ppb)	Normalized mean bias (%)	Normalized mean error (%)
Northeast	189	42.4	42.5	0.71	0.1	9.1	0.3	17.2
Upper Midwest	107	42.5	39.1	0.70	-3.4	9.1	-8.0	17.2
Ohio Valley	236	45.4	45.8	0.69	0.4	8.3	0.8	14.7
Southeast	177	40.2	43.4	0.76	3.3	8.8	8.2	17.7
South	145	42.0	43.5	0.73	1.5	8.8	3.6	16.7
Northern Rockies and Plains	55	46.8	43.1	0.64	-3.7	9.3	-7.9	16.4
Southwest	117	54.3	52.5	0.46	-1.8	10.2	-3.4	15.5
Northwest	28	41.4	44.0	0.69	2.7	12.4	6.4	21.0
West	200	51.6	50.1	0.74	-1.5	10.3	-2.9	16.1
All	**1258**	**45.4**	**45.3**	**0.72**	**-0.1**	**9.3**	**-0.2**	**16.4**

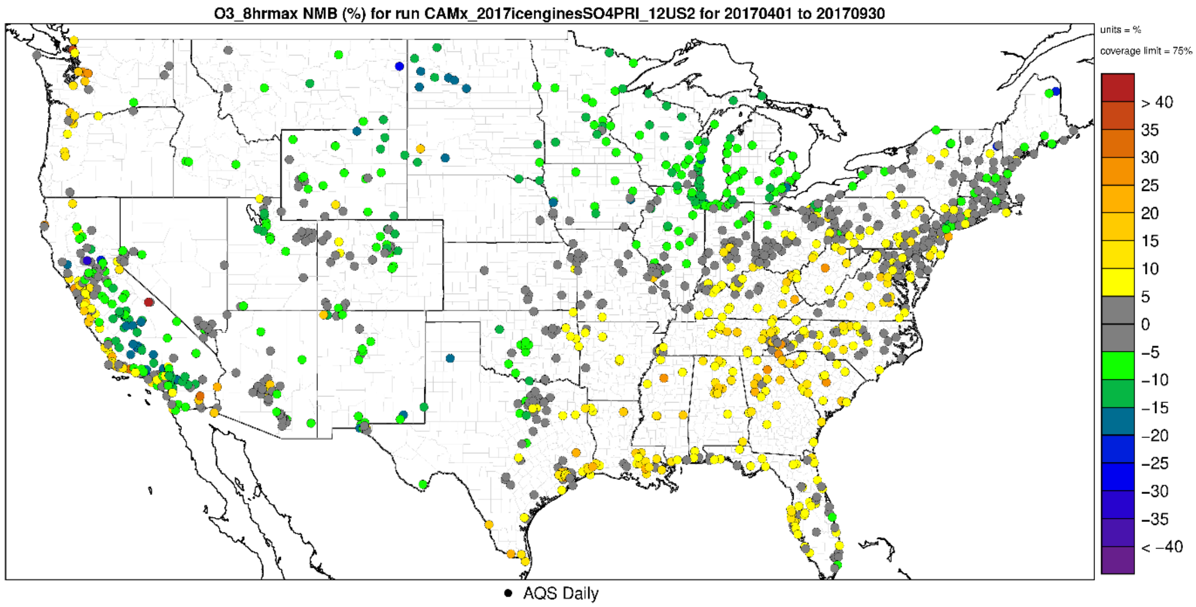

Figure B-4 Map of 2017 CAMx MDA8 Normalized Mean Bias (%) for April–September at all U.S. monitoring sites in the model domain

B.1.2 Source Apportionment Modeling

The contribution of specific emissions sources to ozone in the 2017 modeled case were 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 contributions from the emissions in each individual tag to hourly modeled concentrations of ozone.

For this analysis ozone contributions were modeled using the Ozone Source Apportionment Technique (OSAT) tool. In this modeling, VOC emissions from oil and natural gas operations were tagged separately for 3 regions of the U.S. regions. The model-produced gridded hourly ozone contributions from emissions from each of the source tags which we aggregated up to an ozone metric relevant to recent health studies (i.e. the April-September average of the MDA8 ozone concentration). The April-September average of the MDA8 ozone contributions from each regional oil and natural gas tag were summed to produce a spatial field representing national oil and natural gas VOC contributions to ozone across the United States (Figure B-5).

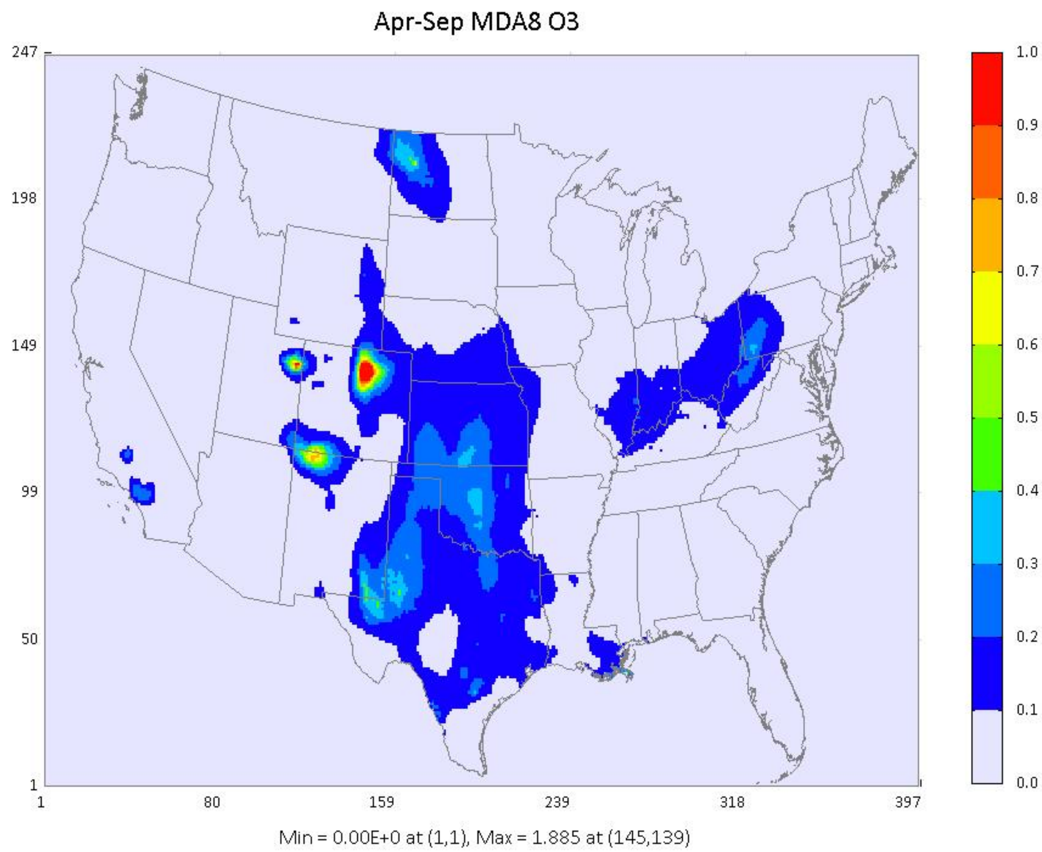

Figure B-5 Contributions of 2017 Oil and Natural Gas VOC Emissions across the Contiguous U.S. to the April-September Average of MDA8 Ozone.

B.2 Applying Modeling Outputs to Quantify a National VOC-Ozone Benefit Per-Ton Value

Following an approach detailed in the RIA and TSD for the Revised Cross-State Update, we estimated the number and value of ozone-attributable premature deaths and illnesses for the purposes of calculating a national ozone VOC benefit per-ton value for the proposed policy scenario (U.S. EPA, 2021b; U.S. EPA, 2021c).

The 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 methods reflecting evidence reported in the 2020 Ozone ISA (U.S. EPA., 2020) and accounting for recommendations from the Science Advisory Board. When updating each health endpoint the 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 Pollution Rule for the 2008 Ozone NAAQS Update titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* (U.S. EPA 2021c).

In brief, we used the environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) to quantify counts of estimated premature deaths and illnesses attributable to summer season average ozone concentrations using the modeled surface described above (Section B.4). We calculate effects using a health impact function, which 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. We next estimate the economic value of these ozone-attributable effects.

We performed BenMAP-CE analyses for each year between 2023 and 2035, using the single model surface described above, but accounting for the change in population size, baseline death rates and income growth in each future year (Section B.4). We next divided the sum of the monetized ozone benefits in each year the April-September VOC emissions associated with the oil and natural gas source apportionment tags in the 2017 CAMx modeling to determine a benefit per ton value for each year from 2023–2035. Emissions totals for the oil and natural gas sector used in the contribution modeling are reported in U.S. EPA (2021). Finally, the benefit per ton values were multiplied by the expected national VOC emissions changes in each year, as reported in Section 2. Since values reported in Section 2 were annual totals, we assume the emissions changes are distributed evenly across months of the year and divide emissions changes by two to estimate the April-September VOC changes expected from this proposed rule.

B.3 Uncertainties and Limitations of Air Quality Methodology

The approach applied in this screening analysis is consistent with how air quality impacts have been estimated in past regulatory actions (U.S. EPA, 2019; U.S. EPA, 2021b). However, in this section we acknowledge and discuss several limitations.

First, the 2017 modeled ozone concentrations have some uncertainty. While all models have some level of inherent uncertainty in their formulation and inputs, evaluation of the model outputs against ambient measurements shows that ozone model performance is within the range of model performance reported from photochemical modeling studies in the literature (Simon et al., 2012; Emery et al., 2017) and is adequate for estimating ozone impacts of VOC emissions for the purpose of this rulemaking.

In any complex analysis using estimated parameters and inputs from a variety of models, there are likely to be many sources of uncertainty. This analysis is no exception. This analysis includes many data sources as inputs, including emissions inventories, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data for monetizing benefits, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). Each of these inputs are uncertain and generate uncertainty in the benefits estimate. When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits. Therefore, the estimates of annual benefits should be viewed as representative of the magnitude of benefits expected, rather than the actual benefits that would occur every year.

Because regulatory health impacts are distributed based on the degree to which housing and work locations overlap geographically with areas where atmospheric concentrations of pollutants change, it is difficult to fully know the distributional impacts of a rule. Air quality models provide some information on changes in air pollution concentrations induced by regulation, but it may be difficult to identify the characteristics of populations in those affected areas, as well as to perform high-resolution air quality modeling nationwide. Furthermore, the overall distribution of health benefits will depend on whether and how households engage in averting behaviors in response to changes in air quality, e.g., by moving or changing the amount of time spent outside (Sieg et al., 2004).

Another limitation of the methodology is that it treats the response of ozone benefits to changes in emissions from the tagged sources as linear. For instance, the benefits associated with a 10 percent national change in oil and natural gas VOC emissions would be estimated to be twice as large as the benefits associated with a 5 percent change in nation oil and natural gas VOC emissions. The methodology therefore does not account for 1) any potential nonlinear responses of ozone atmospheric chemistry to emissions changes and 2) any departure from linearity that may occur in the estimated ozone-attributable health effects resulting from large changes in ozone exposures. We note that the emissions changes between scenarios are relatively small compared to 2017 emissions totals from all sources. 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). Additionally, past studies have shown that ozone responds more linearly to changes in VOC emissions than changes in NO_X emissions (Hakami et al., 2003; Hakami et al., 2004). Therefore, it is reasonable to expect that the ozone benefits from expected VOC emissions changes from this proposed rule can be adequately represented using this this linear assumption.

A final limitation is that the source apportionment ozone contributions reflect the spatial and temporal distribution of the emissions from each source tag in the 2017 modeled case. The representation of the spatial patterns of ozone contributions are important because benefits calculations depend on the spatial patterns of ozone changes in relationship to spatial distribution of population and health incidence values. While we accounted for changes the size of the population, baseline rates of death and income, we assume the spatial pattern of oil and natural gas VOC contributions to ozone remain constant at 2017 levels. Thus, the current methodology does not allow us to represent any expected changes in the spatial patterns of ozone that could result from changes in oil and natural gas emissions patterns in future years or from spatially heterogeneous emissions changes resulting from this proposed rule. For instance, the method does not account for the possibility that new sources would change the spatial distribution of oil and natural gas VOC emissions. In addition, the method does not account for any changes in spatial patterns of ozone that would result from spatially varying emissions change which could result from differing impacts of this proposed rule in locations with existing state regulations. For instance, in Section 2 we describe the impact of existing regulations in Colorado and California. Due to the stringency of current on-the-books oil and natural gas regulations in these and other states, we do not expect large impacts from this rule of VOC emissions in those states. We note specifically that Figure 4-2 depicts that oil and natural gas VOC contributions to ozone are large in Colorado compared to other parts of the contiguous US. In addition, Figure 4-2 shows that there are some modeled oil and natural gas VOC contributions to ozone in densely populated southern California. Since VOC emissions impacts from this rule are calculated at a national level, at this time we do not have more refined information which could be used to spatially vary the response of ozone impacts to proposed VOC emissions changes. As an example, the fraction of national ozone benefits that occur in Colorado and California locations is approximately one quarter of the 2026 benefits in the tables below and also note that ozone benefits occuring in locations with existing strong state regulations may not be realized. We also note that while we have identified existing state regulations in California and Colorado, we have not characterized the impacts of state regulations from other states on VOC emissions impacts or associated ozone benefits nor have we characterized how spatially heterogeneous emissions changes due to other factors would impact the quantified benefits.

B.4 Estimated Screening-Level Benefits

Table B-2 Estimated Avoided Ozone-Related Premature Respiratory Mortality and Illnesses under the Primary Proposed NSPS OOOOb and EG OOOOc Option in 2026[a]

Avoided premature respiratory mortality		Proposed NSPS OOOOb and EG OOOOc
Long-term exposure	Turner et al. (2016)	200
Short-term exposure	Katsouyanni et al. (2009)[b] and Zanobetti et al. (2008)[c,d] pooled	9.2
Avoided respiratory morbidity effects		
Long-term exposure	Asthma onset[d]	1,700
	Allergic rhinitis symptoms [f,e]	9,700
Short-term exposure	Hospital admissions—respiratory[b]	24
	ED visits—respiratory[g]	510
	Asthma symptoms[g]	310,000
	Minor restricted-activity days[b]	140,000
	School absence days [c,h]	110,000

[a] Values rounded to two significant figures. The fraction of national ozone benefits that occur in Colorado and California locations is approximately one quarter of the total benefits. Long-term exposure health benefit estimates were calculated using annual baseline incidence rates, while short-term exposure health benefits were calculated using May-September baseline incidence rates.
[b] Converted O_3 risk estimate metric from MDA1 to MDA8.
[c] Converted O_3 risk estimate metric from DA8 to MDA8.
[d] Applied risk estimate derived from June-August exposures to April-September estimates of O_3.
[e] Converted O_3 risk estimate metric from DA24 to MDA8.
[f] Applied risk estimate derived from May-September exposures to April-September estimates of O_3.
[g] Applied risk estimate derived from full year exposures to April-September estimates of O_3.
[h] Applied risk estimate derived from January-June exposures to April-September estimates of O_3.

Table B-3 Benefit Per Ton Estimates of Ozone-Attributable Premature Mortality and Illnesses for the Proposal in 2026

	Benefit Per Ton of Reducing VOC from the Oil and Natural Gas Sector
Short-term mortality and morbidity health effects (discounted at 3%)	$230
Short-term mortality and morbidity health effects (discounted at 7%)	$210
Long-term mortality and morbidity health effects (discounted at 3%)	$1,800
Long-term mortality and morbidity health effects (discounted at 7%)	$1,600

Table B-4 Estimated Discounted Economic Value of Ozone-Attributable Premature Mortality and Illnesses under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (million 2019$)[a]

	Primary Proposed NSPS OOOOb and EG OOOOc Option	
Year	3% Discount Rate	7% Discount Rate
2023	$4.3[b] to $33[c]	$3.8[b] to $29[c]
2024	$6.4[b] to $49[c]	$5.7[b] to $44[c]
2025	$8.6[b] to $67[c]	$7.7[b] to $59[c]
2026	$160[b] to $1,200[c]	$140[b] to $1,100[c]
2027	$160[b] to $1,200[c]	$140[b] to $1,100[c]
2028	$150[b] to $1,200[c]	$140[b] to $1,100[c]
2029	$150[b] to $1,200[c]	$130[b] to $1,100[c]
2030	$150[b] to $1,200[c]	$130[b] to $1,100[c]
2031	$140[b] to $1,200[c]	$130[b] to $1,000[c]
2032	$140[b] to $1,200[c]	$130[b] to $1,000[c]
2033	$140[b] to $1,100[c]	$120[b] to $1,000[c]
2034	$140[b] to $1,100[c]	$120[b] to $1,000[c]
2035	$140[b] to $1,100[c]	$120[b] to $1,000[c]

[a] Values rounded to two significant figures. Benefit per ton estimates used to develop these estimated economic valuations were derived from source-apportionment modeling and are available in Table B-3. The fraction of national ozone benefits that occur in Colorado and California locations in 2026 is approximately one quarter of the total benefits.
[b] Includes ozone mortality estimated using the pooled Katsouyanni et al. (2009) and Zanobetti and Schwartz (2008) short-term risk estimates.
[c] Includes ozone mortality estimated using the Turner et al. (2016) long-term risk estimate.

Table B-5 Stream of Human Health Benefits under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035: Monetized Benefits Quantified as Sum of Avoided Morbidity Health Effects and Avoided Long-term Ozone Mortality (discounted at 3 percent to 2021; million 2019$)[a]

Year	Primary Proposed NSPS OOOOb and EG OOOOc Option
2023	$33
2024	$49
2025	$67
2026	$1,200
2027	$1,200
2028	$1,200
2029	$1,200
2030	$1,200
2031	$1,200
2032	$1,200
2033	$1,100
2034	$1,100
2035	$1,100
Present Value (PV)	**$9,600**
Equivalent Annualized Value (EAV)	**$820**

[a] Benefits calculation includes ozone-related morbidity effects and avoided ozone-attributable deaths quantified using the Turner et al. (2016) long-term risk estimate.

Table B-6 Stream of Human Health Benefits under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035: Monetized Benefits Quantified as Sum of Avoided Morbidity Health Effects and Avoided Long-term Ozone Mortality (discounted at 7 percent to 2021; million 2019$)[a]

Year	Proposed NSPS OOOOb and EG OOOOc
2023	$29
2024	$44
2025	$59
2026	$1,100
2027	$1,100
2028	$1,100
2029	$1,100
2030	$1,100
2031	$1,000
2032	$1,000
2033	$1,000
2034	$1,000
2035	$1,000
Present Value (PV)	**$6,600**
Equivalent Annualized Value (EAV)	**$650**

[a] Benefits calculated as value of avoided ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. (2016) study and ozone-related morbidity effects).

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APPENDIX C ADDITIONAL INFORMATION ON ENVIRONMENTAL JUSTICE ANALYSIS

In Section 4.2.3 we quantitatively assessed EJ implications of ozone-related impacts from VOC emissions in the baseline, focusing particularly on differences in potential exposure to ozone among subpopulations of interest. As noted, we stopped short of characterizing the respiratory mortality risk among these populations, or drawing comparisons among them, due to the impact on results caused by differences in the age distributions, and therefore baseline incidence rates of respiratory mortality, of White and non-White populations.

Here, we provide additional information to show how other factors, in addition to ozone levels, may translate into respiratory mortality risk among potential EJ populations (Sections C.2 and C.2.2). Notably, risk estimates also incorporate:

- The number of people affected by the air pollution reduction. In this instance, the population is further divided by race/ethnicity, age, and sex.
- The relationship between exposure and health impact baseline incidence rates, or more specifically, the percentage change in the risk of an adverse health effect due to a one-unit change in ambient air pollution. These concentration-response functions are generally derived from epidemiologic studies and in this case, the same concentration-response function is applied to each subpopulation.
- The average number of people who die in a given population over a given period of time. This is commonly referred to as the baseline incidence rate. For these analyses, an overall baseline incidence rate is applied to both sexes and all age groups. In contrast, race- and ethnicity-specific, or stratified, baseline incidence rates were used to estimate risk more accurately within each demographic group when calculating risk in racial and ethnic populations.[87] Risk estimates using the overall incidence rate are also provided, for comparison.

[87] Information on how the race-stratified baseline incidence were developed can be found in Section C.1.

However, of the above bullets, only baseline incidence rates are brought into the risk calculation as the population is normalized across groups and a single overall concentration-response function is used to relate exposure to health impacts.

C.1 Development of Race- and Ethnicity-Stratified Baseline Incidence Rates for Respiratory Mortality[88]

Previously EPA has used race- and ethnicity-stratified baseline incidence rates for the all-cause mortality health endpoint only. In Section APPENDIX C, we use race- and ethnicity stratified baseline incidence rates to estimate the respiratory mortality risk associated with ozone from oil and natural gas VOC emissions in a 2017 baseline scenario. These race- and ethnicity-stratified baseline incidence rates were developed using an approach similar to what was used to develop the original stratified all-cause mortality rates, with the addition of a spatial scale level (i.e., rural and urban state-level).

C.1.1 Race-stratified Incidence Rates

To estimate race-stratified and age-stratified respiratory mortality incidence rates at the county level, we downloaded all-cause and respiratory mortality data from 2007 to 2016 from the CDC WONDER mortality database.[89] Race-stratified incidence rates were calculated for the following age groups: < 1 year, 1–4 years, 5–14 years, 15–24 years, 25–34 years, 35–44 years, 45–54 years, 55–64 years, 65–74 years, 75–84 years, and 85+ years. To address the frequent county-level data suppression for race-specific death counts, we stratified the county-level data into two broad race categories, White and Non-White populations. In a later step, we stratified the non-White incidence rates by race (Black, Asian, Native American) using the relative magnitudes of incidence values by race at the regional level, described in more detail below.

We followed the methods outlined in Section D.1.1 of the BenMAP User Manual with one notable difference in methodology; we included an intermediate spatial scale between county and

[88] This is the first time EPA has used race- and ethnicity-stratified respiratory mortality baseline incidence rates, although we have previously used race- and ethnicity-stratified all-cause mortality baseline incidence rates. Additionally, we have improved our method of developing race- and ethnicity-stratified respiratory mortality baseline incidence rates to better account for urban/rural status. Please note, all baseline incidence rates are also stratified into the following age ranges: < 1, 1–4, 5–9, 10–14, 15–19, 20–24, 25–29, 30–34, 35–39, 40–44, 45–49, 50–54, 55–59, 60–64, 65–69, 70–74, 75–79, 80–84, and 85–99.

[89] https://wonder.cdc.gov/

state for imputation purposes.[90] We designated urban and rural counties within each state using CDC WONDER and, where possible, imputed missing data using the state-urban and state-rural classifications before relying on broader statewide data. We followed methods for dealing with suppressed and unreliable data at each spatial scale as described in Section D.1.1.

A pooled non-White incidence rate masks important differences in mortality risks by race. To estimate county-level mortality rates by individual race (Black, Asian, Native American), we applied regional race-specific incidence relationships to the county-level pooled non-White incidence rates. We calculated a weighted average of race-specific incidence rates using regional incidence rates for each region/age/race group normalized to one reference population (the Asian race group) and county population proportions based on race-specific county populations from CDC WONDER where available. In cases of population suppression across two or more races per county, we replaced all three race-specific population proportions derived from CDC WONDER with population proportions derived from 2010 Census data in BenMAP-CE (e.g., 50 percent Black, 30 percent Asian, 20 percent Native American).

C.1.2 Ethnicity-stratified Incidence Rates

To estimate ethnicity-stratified and age-stratified respiratory mortality incidence rates at the county level, we downloaded all-cause and respiratory mortality data from 2007 to 2016 from the CDC WONDER mortality database.[91] Ethnicity-stratified incidence rates were calculated for the following age groups: < 1 year, 1–4 years, 5–14 years, 15–24 years, 25–34 years, 35–44 years, 45–54 years, 55–64 years, 65–74 years, 75–84 years, and 85+ years. We stratified county-level data by Hispanic origin (Hispanic and non-Hispanic). We followed the methods outlined in Section D.1.1 to deal with suppressed and unreliable data. We also included an intermediate spatial scale between county and state designating urban and rural counties for imputation purposes, described in detail in Section D.1.3 of the BenMAP User Manual.[92]

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[90] https://www.epa.gov/sites/default/files/2015-04/documents/benmap-ce_user_manual_march_2015.pdf
[91] https://wonder.cdc.gov/
[92] https://www.epa.gov/sites/default/files/2015-04/documents/benmap-ce_user_manual_march_2015.pdf

C.2 Environmental Justice Risk Estimates

In addition to the assessment of CAP exposures among potential EJ populations (Section 4.2.3), here we present risk rate estimates across potential EJ populations.

C.2.1 Average Respiratory Mortality Risk Estimates

Average population-normalized risk due to ozone from oil and natural gas VOC emissions for each population with potential EJ concerns are shown on the rightmost column in Figure C-6. To allow for risk comparisons across populations, the right column of mortality per 100,000 people is calculated by dividing the number of ozone-attributable respiratory deaths in 2017 (central column) by the total baseline number of respiratory deaths occuring in 2017 (leftmost column) and then multiplying by 100,000. For each race and ethnicity, both the overall and corresponding stratified baseline rate was applied, shown in the 'Respiratory Mortality Incidence Dataset' column.

Overall, risk across sexes and races/ethnicities generally appeared similar to that of the overall population, with slight increases in female, White, and non-Hispanic populations. There was also increased risk in older adults aged 65–99. Lower risk in Native American and Hispanic populations may seem counterintuitive when taken together with increased average exposures in those populations shown in Figure C-6. However, populations of color are considerably younger than White populations (Pew, 2019), and the majority of air pollution-attributable mortality occurs in older adults. Lower baseline incidence in younger population of color counteracts the slightly higher ozone exposure and results in lower risk within those races/ethnicities for a single future year.

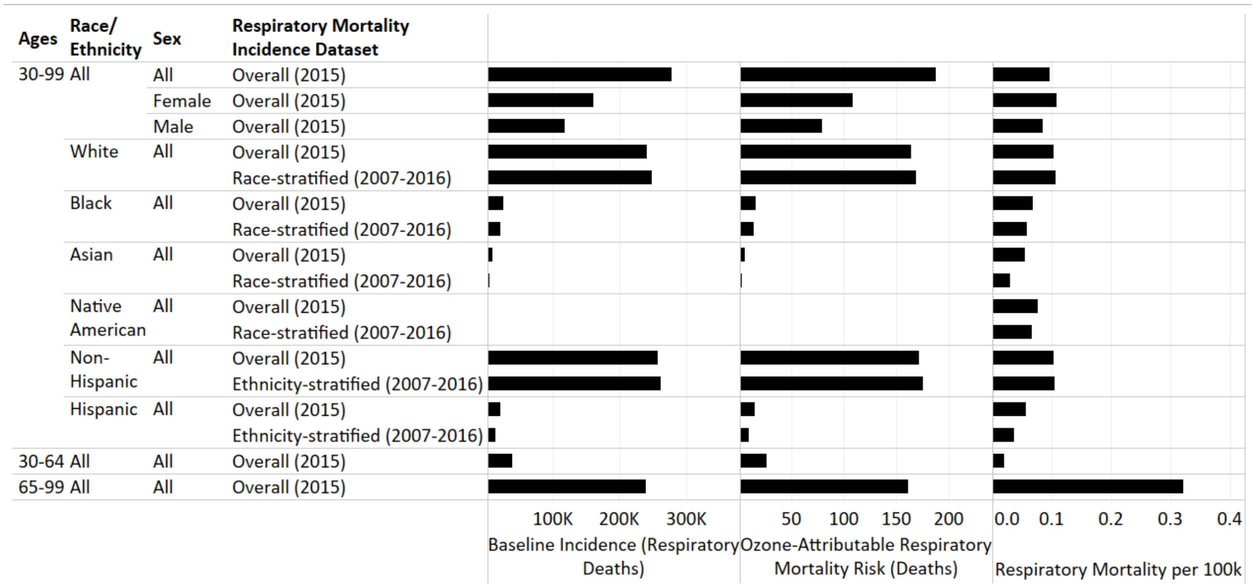

Figure C-6 Average Respiratory Mortality Risk from Ozone Concentrations from Oil and Natural Gas VOC Emissions by Population

C.2.2 Respiratory Mortality Risk Distributions

While average exposure concentrations and risk estimates across demographic populations can convey some insight, distributional information, while more complex, can provide a more comprehensive understanding of the analytical results. As such, we provide the running sum percentage of each population plotted against the increasing ozone concentration and respiratory mortality per 100,000 from oil and natural gas VOC emissions, so as to permit the direct comparison of demographic populations with different absolute numbers.

Figure C-7 shows the cumulative population distribution of White (black), non-Hispanic (grey), Hispanic (dark orange), Native American (light orange), Black or African American (dark blue), and Asian (light blue) populations plotted against the ozone concentration from oil and natural gas VOC emissions and the respiratory mortality per 100,000 people. Only race- and ethnicity-stratified baseline incidence rates are provided as the impact of stratified incidence rates is minimal (Figure C-7).

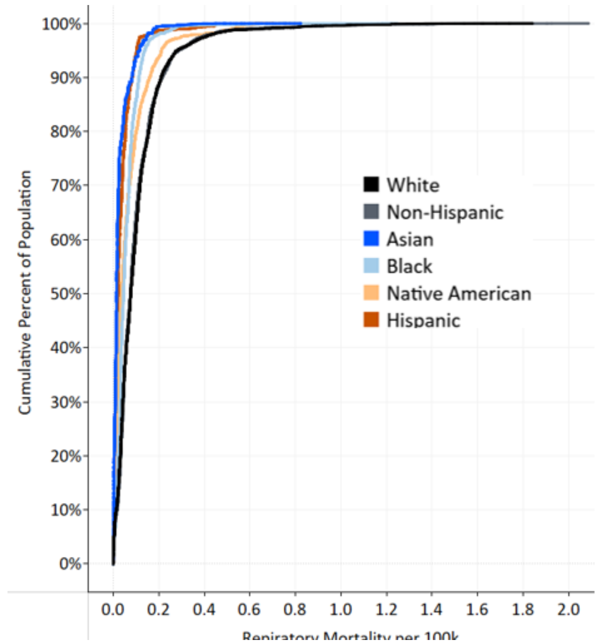

Figure C-7 Ozone Concentrations and Ozone-Attributable Respiratory Mortality Risk by Age

Figure C-8 shows the cumulative population distribution of males (orange) and females (blue) plotted against the ozone concentration from oil and natural gas VOC emissions and the respiratory mortality per 100,000 people.

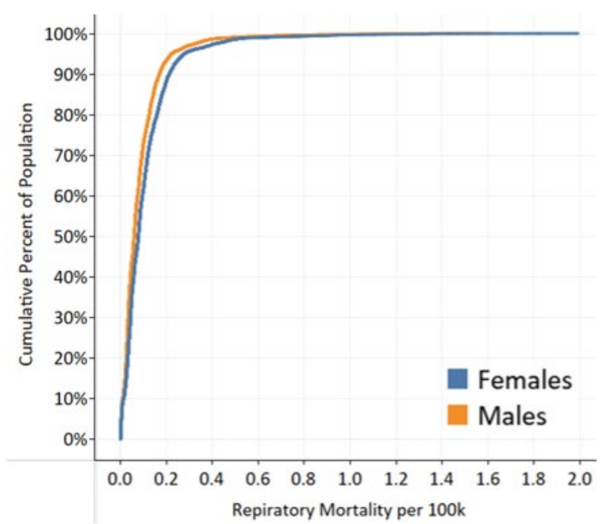

Figure C-8 Ozone Concentrations and Ozone-Attributable Respiratory Mortality Risk by Sex

Figure C-9 shows the cumulative population distribution of age ranges (30-64 in black and 65-99 in orange) plotted against ozone concentrations from oil and natural gas VOC emissions. Respiratory mortality risk across children and younger adults are not reported as the concentration-response function was derived from a cohort aged 30+.

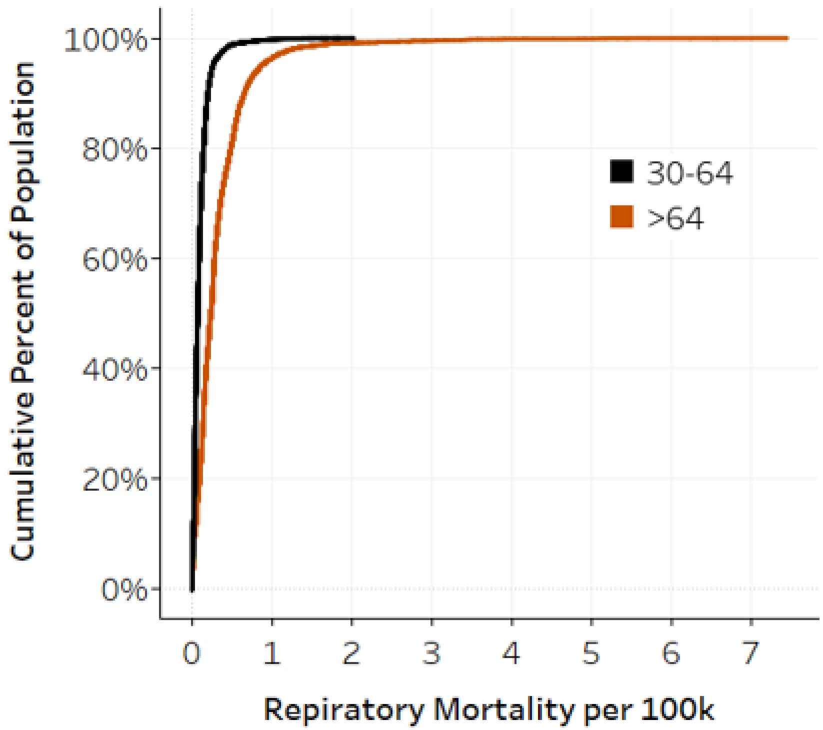

Figure C-9 Concentrations and Ozone-Attributable Respiratory Mortality Risk by Age Range

C.3 Limitations of this Environmental Justice Risk Analysis

Risk results shown in this Appendix are strongly influenced by the age distributions of various potential EJ subpopulations. Specifically, populations with higher median ages and those with larger populations of older adults (e.g., White populations), are associated with substantially higher baseline incidence rates of respiratory mortality. Higher baseline mortality rates translate into higher estimates of risk that can obfuscate impacts from small differences in ozone exposure levels.

C.4 References

Pew Research Center (Pew). 2019. *The most common age among whites in U.S. is 58 – more than double that of racial and ethnic minorities*. Washington DC. Published July 30, 2019. https://www.pewresearch.org/fact-tank/2019/07/30/most-common-age-among-us-racial-ethnic-groups/. Accessed August 3, 2021.

United States Environmental Protection Agency	Office of Air Quality Planning and Standards Health and Environmental Impacts Division Research Triangle Park, NC	Publication No. EPA-452/R-21-003 October 2021