United States
Environmental Protection
Agency

Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants

CONTACT INFORMATION

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DEDICATION

This Regulatory Impact Analysis is dedicated to the memory of Lillian Grace Bradley who made substantial contributions to this analysis and report. Lillian freely expressed her fundamental belief that everyone has an inherent right to be treated with dignity and respect, regardless of their position or background, and she was a recognized leader in Environmental Justice and Tribal issues at EPA. She expressed her deep regard for others through individual acts of kindness as well as her dedication to increasing social awareness and emotional intelligence in the workplace. Her caring, integrity, and outspokenness were a gift to us all. Lillian challenged us to lead our very best life. She will be greatly missed.

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Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants

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TABLE OF CONTENTS

Table of Contents iv
List of Tables x
List of Figures xviii
Acronyms xxi
Executive Summary ES-1
ES.1 Background and Context of Proposed EGU GHG Existing Source Guidelines ES-1
ES.2 Summary of Proposed EGU GHG Existing Source Guidelines ES-1
ES.3 Control Strategies for Existing EGUs ES-3
ES.4 Costs of Existing EGU Guidelines ES-7
ES.5 Monetized Climate Benefits and Health Co-benefits for Existing EGUs ES-9
ES.5.1 Estimating Global Climate Benefits ES-13
ES 5.2 Estimating Air Pollution Health Co-Benefits ES-15
ES 5.3 Combined Benefits Estimates ES-17
ES.6 Monetized Benefits, Compliance Costs and Net Benefits of the Proposed Guidelines for Existing Sources ES-19
ES.7 Economic Impacts of the Proposed Emission Guidelines for Existing EGUs ES-24
ES.8 Economic Impacts of the Proposed Guidelines for Existing EGUs for Sectors Other Than the EGU Sector and for Employment ES-24
ES.9 Modified and Reconstructed Sources ES-26
ES.10 References ES-27
Chapter 1: Introduction and Background 1-1
1.1 Introduction 1-1
1.2 Legal, Scientific and Economic Basis for this Rulemaking 1-1
1.2.1 Statutory Requirement 1-1
1.2.2 Health and Welfare Impacts from Climate Change 1-2
1.2.3 Market Failure 1-3
1.3 Summary of Regulatory Analysis 1-3
1.4 Background for the Proposed EGU Existing Source GHG Guidelines 1-4
1.4.1 Base Case and Years of Analysis 1-4
1.4.2 Definition of Affected Sources 1-5
1.4.3 Regulated Pollutant 1-5

1.4.4 Emission Guidelines 1-6
1.5 Organization of the Regulatory Impact Analysis 1-7
1.6 References 1-8
Chapter 2: Electric Power Sector Profile 2-1
2.1 Introduction 2-1
2.2 Power Sector Overview 2-1
2.2.1 Generation 2-1
2.2.2 Transmission 2-5
2.2.3 Distribution 2-6
2.3 Deregulation and Restructuring 2-6
2.4 Emissions of Greenhouse Gases from Electric Utilities 2-8
2.5 Improving GHG Performance at Existing EGUs 2-12
2.6 GHG and Clean Energy Regulation in the Power Sector 2-14
2.6.1 State Policies 2-14
2.6.2 Federal Policies 2-16
2.7 Revenues, Expenses, and Prices 2-19
2.8 Natural Gas Market 2-22
2.9 Electricity Demand and Demand Response 2-25
2.10 References 2-28
Chapter 3: Cost, Economic, and Energy Impacts 3-1
3.1 Introduction 3-1
3.2 Overview 3-1
3.3 Power Sector Modelling Framework 3-2
3.3.1 Recent Updates to EPA's Base Case using IPM (v.5.13) 3-4
3.4 State Goals in this Proposal 3-6
3.5 Compliance Scenarios Analyzed 3-9
3.6 Demand Side Energy Efficiency 3-14
3.6.1 Projected Demand-Side Energy Savings 3-14
3.6.2 Demand-Side Energy Efficiency Total Costs 3-17
3.7 Projected Power Sector Impacts 3-19
3.7.1 Projected Emissions 3-19
3.7.2 Projected Compliance Costs 3-22
3.7.3 Projected Compliance Actions for Emissions Reductions 3-24
3.7.4 Projected Generation Mix 3-25

3.7.5 Projected Incremental Retirements ... 3-32
3.7.6 Projected Capacity Additions ... 3-34
3.7.7 Projected Coal Productions for the Electric Power Sector ... 3-36
3.7.8 Projected Fuel Price Impacts ... 3-37
3.7.9 Projected Retail Electricity Prices ... 3-38
3.7.10 Projected Electricity Bill Impacts ... 3-43
3.8 Projected Primary PM Emissions from Power Plants ... 3-44
3.9 Limitations of Analysis ... 3-45
3.10 Significant Energy Impacts ... 3-46
3.11 Monitoring, Reporting, and Recordkeeping Costs ... 3-47
3.12 Social Costs ... 3-48
3.13 References ... 3-53
Appendix 3A: Analysis of Potential Upstream Methane Emissions Changes in Natural Gas Systems and Coal Mining ... 3A-1
3A.1 General Approach ... 3A-1
3A.1.1 Analytical Scope ... 3A-1
3A.1.2 Coal Mining Source Description ... 3A-3
3A.1.3 Natural Gas Systems Source Description ... 3A-4
3A.1.4 Compliance Approaches Examined ... 3A-6
3A.1.5 Activity Drivers ... 3A-6
3A.2 Results ... 3A-7
3A.2.1 Primary Results ... 3A-7
3A.2.2 Sensitivity Analysis: Side Case Incorporating More Coal Production Geographic Detail ... 3A-9
3A.2.3 Uncertainties and Limitations ... 3A-10
3A.3 Methodologies ... 3A-11
3A.3.1 Coal Mining ... 3A-11
3A.3.2 Natural Gas Systems ... 3A-14
3A.4 References ... 3A-31
Chapter 4: Estimated Climate Benefits and Human Health Co-benefits ... 4-1
4.1 Introduction ... 4-1
4.2 Estimated Climate Benefits from CO_2 ... 4-1
4.2.1 Climate Change Impacts ... 4-2
4.2.2 Social Cost of Carbon ... 4-7
4.3 Estimated Human Health Co-Benefits ... 4-14

4.3.1 Health Impact Assessment for $PM_{2.5}$ and Ozone 4-16
4.3.2 Economic Valuation for Health Co-benefits 4-21
4.3.3 Benefit-per-ton Estimates for $PM_{2.5}$ 4-23
4.3.4 Benefit-per-ton Estimates for Ozone 4-24
4.3.5 Estimated Health Co-Benefits Results 4-25
4.3.6 Characterization of Uncertainty in the Estimated Health Co-benefits 4-39
4.4 Combined Climate Benefits and Health Co-benefits Estimates 4-46
4.5 Unquantified Co-benefits 4-51
4.5.1 HAP Co-benefits 4-53
4.5.2 Additional NO_2 Health Co-Benefits 4-57
4.5.3 Additional SO_2 Health Co-Benefits 4-58
4.5.4 Additional NO_2 and SO_2 Welfare Co-Benefits 4-59
4.5.5 Ozone Welfare Co-Benefits 4-60
4.5.6 Carbon Monoxide Co-Benefits 4-60
4.5.7 Visibility Impairment Co-Benefits 4-61
4.6 References 4-62
Appendix 4A: Generating Regional Benefit-per-Ton Estimates for Electric Generating Units 4A-1
4A.1 Overview of Benefit-per-Ton Estimates 4A-1
4A.2 Underlying Source Apportionment Air Quality Modeling 4A-2
4A.3 Regional $PM_{2.5}$ Benefit-per-Ton Estimates for EGUs 4A-3
4A.4 Regional Ozone Benefit-per-Ton Estimates 4A-16
4A.5 Evaluating the Benefit-per-Ton Estimates 4A-20
4A.6 References 4A-26
Chapter 5: Economic Impacts – Markets Outside the Electricity Sector 5-1
5.1 Introduction 5-1
5.2 Summary of Secondary Market Impacts of Energy Price Changes 5-3
5.2.1 Share of Total Production Costs 5-4
5.2.2 Ability to Substitute between Inputs to the Production Process 5-5
5.2.3 Availability of Substitute Goods and Services 5-5
5.3 Conclusions 5-6
Chapter 6: Employment Impact Analysis 6-1
6.1 Introduction 6-1
6.2 Overview of the Proposed EGU GHG Existing Source Guidelines 6-2
6.2.1 Determining State Goals Utilizing the Four Building Blocks 6-2

6.3 Economic Theory and Employment 6-3
6.4 Current State of Knowledge Based on the Peer-Reviewed Literature 6-7
6.4.1 Regulated Sector 6-8
6.4.2 Labor Supply Impacts 6-9
6.5 Recent Employment Trends...6-10
6.5.1 Electric Power Generation 6-11
6.5.2 Fossil Fuel Extraction 6-12
6.5.3 Clean Energy Employment Trends 6-15
6.6 Projected Sectoral Employment Changes due to Proposed Guidelines 6-19
6.6.1 Projected Changes in Employment in Electricity Generation and Fossil Fuel Extraction..........6-21
6.6.2 Projected Changes in Employment in Demand-Side Energy Efficiency Activities...................6-27
6.7 Conclusion 6-32
6.8 References...6-35
Appendix 6A: Estimating Supply-Side Employment Impacts of the Proposed EGU GHG Existing Source Guidelines 6A-1
6A.1 General Approach 6A-1
6A.1.1 Employment Effects Included In the Analysis...6A-2
6A.2 Employment Changes due to Heat Rate Improvements..6A-3
6A.2.1 Employment Changes Due to Building (or Avoiding) New Generation Capacity 6A-5
6A.2.2 Employment Changes due to Coal and Oil/Gas Retirements..6A-8
6A.2.3 Employment Changes due to Coal and Oil/Gas Retirements..6A-8
Chapter 7: Statutory and executive Order Analysis...7-1
7.1 Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review 7-1
7.2 Paperwork Reduction Act 7-3
7.3 Regulatory Flexibility Act 7-4
7.4 Unfunded Mandates Reform Act (UMRA) 7-5
7.5 Executive Order 13132, Federalism...7-7
7.6 Executive Order 13045, Protection of Children from Environmental Health Risks and Safety..........7-8
7.7 Executive Order 13211, Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use…………………………………………………………………….......................7-8
7.8 National Technology Transfer and Advancement Act (NTTAA) 7-9
7.9 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations…………………………………………………………............................7-9
7.10 Executive Order 13175 - Consultation and Coordination with Indian Tribal Governments 7-13

Chapter 8: Comparison of Benefits and Costs 8-1
8.1 Comparison of Benefits and Costs 8-1
8.2 Uncertainty Analysis 8-7
8.2.1 Uncertainty in Abatement Costs and Compliance Approaches 8-7
8.2.2 Uncertainty Associated with $PM_{2.5}$ and Ozone Health Co-Benefits Assessment 8-8
8.2.3 Uncertainty Associated with Estimating the Social Cost of Carbon 8-10
Chapter 9: Benefits, Costs, and Economic Impacts of Standards of Performance for Reconstructed and Modified Electric Utility Generating Units 9-1
9.1 Introduction 9-1
9.2 Legal Basis for this Rulemaking 9-1
9.3 Background for the Proposed EGU Reconstructed and Modified Source GHG Standards 9-2
9.3.1 Definition of Affected Sources 9-2
9.3.2 Emission Limits 9-3
9.4 Impacts of the Proposed Reconstructed and Modified Source Standards 9-5
9.4.1 Reconstructed Sources 9-5
9.4.2 Modified Sources 9-6
9.5 Statutory and Executive Order Requirements 9-14
9.5.1 Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review 9-14
9.5.2 Paperwork Reduction Act 9-14
9.5.3 Regulatory Flexibility Act 9-16
9.5.4 Unfunded Mandates Reform Act (UMRA) 9-18
9.5.5 Executive Order 13132, Federalism 9-20
9.5.6 Executive Order 13175, Consultation and Coordination with Indian Tribal Governments 9-21
9.5.7 Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks 9-22
9.5.8 Executive Order 13211, Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use 9-22
9.5.9 National Technology Transfer and Advancement Act 9-22
9.5.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations 9-23
9.6 References 9-25

LIST OF TABLES

Table ES-1. Proposed State Goals (Adjusted MWh-Weighted-Average Pounds of CO_2 per Net MWh from all Affected Fossil Fuel-Fired EGUs) for Options 1 and 2 .... ES-4

Table ES-2. Summary of Climate and Air Pollutant Emission Reductions Option 1[1] ES-6

Table ES-3. Summary of Climate and Air Pollutant Emission Reductions Option 2[1] ES-7

Table ES-4. Summary of Illustrative Compliance Costs ES-8

Table ES-5. Quantified and Unquantified Benefits ES-11

Table ES-6. Combined Estimates of Climate Benefits and Health Co-Benefits for Proposed Existing EGU GHG Rule – Regional Compliance Approach (billions of 2011$)* ES-18

Table ES-7. Combined Estimates of Climate Benefits and Health Co-Benefits for Proposed Existing EGU GHG Rule – State Compliance Approach (billions of 2011$)* ES-19

Table ES-8. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines – 2020 (billions of 2011$) [a] ES-21

Table ES-9. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines – 2025 (billions of 2011$) [a] ES-22

Table ES-10. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines –2030 (billions of 2011$) [a] ES-23

Table 2-1. Existing Electricity Generating Capacity by Energy Source, 2012 2-2

Table 2-2. Electricity Net Generation in 2012 (billion kWh) 2-2

Table 2-3. Total U.S. Electric Power Industry Retail Sales in 2012 (billion kWh) 2-3

Table 2-4. Coal Steam Electricity Generating Units in 2015, by Size, Age, Capacity, and Thermal Efficiency (Heat Rate) 2-4

Table 2-5. Domestic Emissions of Greenhouse Gases, by Economic Sector (million metric tons of CO_2 equivalent) 2-9

Table 2-6. Greenhouse Gas Emissions from the Electricity Sector (Generation, Transmission and Distribution), 2012 (million metric tons of CO_2 equivalent) 2-10

Table 2-7. Fossil Fuel Emission Factors in EPA Modeling Applications 2-11

Table 2-8. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities 2-21

Table 2-9. Projected Revenues by Service Category in 2015 for Public Power and Investor-Owned Utilities (billions) 2-21

Table 3-1. Proposed State Goals (Adjusted MWh-Weighted-Average Pounds of CO_2 Per Net MWh from all Affected Fossil Fuel-Fired EGUs) for Options 1 and 2 3-6

Table 3-2. Projected Base Case CO_2 Emissions Rate (Adjusted MWh-Weighted-Average Pounds of CO_2 Per Net MWh from all Affected Fossil Fuel-Fired EGUs) 3-7

Table 3-3. Net Cumulative Savings as a Percent of Projected BAU Sales 3-16

Table 3-4. Annualized Cost of Demand-Side Energy Efficiency (at discount rates of 3% and 7%, billions 2011$) 3-19

Table 3-5. Projected CO_2 Emission Impacts, Relative to Base Case 3-20

Table 3-6. Projected CO_2 Emission Impacts, Relative to 2005 3-20

Table 3-7. Projected Non-CO_2 Emission Impacts, 2020-2030 3-21

Table 3-8. Annualized Compliance Costs (billions of 2011$) 3-22

Table 3-9. Total Power Sector Generating Costs (IPM) (billions 2011$) 3-23

Table 3-10. Projected Capacity Factor of Existing Coal Steam and Natural Gas Combined Cycle Capacity 3-25

Table 3-11. Generation Mix (thousand GWh) 3-27

Table 3-12. Total Generation Capacity by 2020-2030 (GW) 3-34

Table 3-13. Projected Capacity Additions, Gas (GW)....................3-35

Table 3-14. Projected Capacity Additions, Non-hydro Renewable (GW)....................3-35

Table 3-15. Coal Production for the Electric Power Sector, 2020....................3-36

Table 3-16. Power Sector Gas Use 3-36

Table 3-17. Projected Average Minemouth and Delivered Coal Prices (2011$/MMBtu)....................3-38

Table 3-18. Projected Average Minemouth and Delivered Coal Prices: Percent Change from Base Case Projections....................3-38

Table 3-19. Projected Average Henry Hub (spot) and Delivered Natural Gas Prices (2011$/MMBtu).3-38

Table 3-20. Average Henry Hub (spot) and Delivered Natural Gas Prices: Percent Change from Base Case Projections 3-38

Table 3-21. 2020 Projected Contiguous U.S. and Regional Retail Electricity Prices (cents/kWh)........3-40

Table 3-22. 2025 Projected Contiguous U.S. and Regional Retail Electricity Prices (cents/kWh)........3-41

Table 3-23. 2030 Projected Contiguous U.S. and Regional Retail Electricity Prices (cents/kWh)........3-42

Table 3-24. Projected Changes in Average Electricity Bills....................3-43

Table 3-25. Years 2020, 2025 and 2030: Summary of Annual Respondent Burden and Cost of Reporting and Recordkeeping Requirements (2011$) 3-48

Table 3-26. Annualized Compliance Costs Including Monitoring, Reporting and Recordkeeping Costs Requirements (billions of 2011$)....................3-48

Table 3A-1. Base Year Upstream Methane-Related Emissions in the U.S. GHG Inventory 3A-5

Table 3A-2. Projected Coal Production Impacts, Option 1 ....3A-7

Table 3A-3. Projected Coal Production Impacts, Option 2 ....3A-7

Table 3A-4. Projected Natural Gas Production Impacts, Option 1 .... 3A-7

Table 3A-5. Projected Natural Gas Production Impacts, Option 2 .... 3A-7

Table 3A-6. Upstream Emissions Changes, Baseline to Compliance Scenarios 3A-9

Table 3A-7. Upstream Emissions Changes, Baseline to Compliance Scenarios, Side Case Incorporating More Coal Production Geographic Detail 3A-10

Table 4-1. Climate Effects 4-2

Table 4-2. Global Social Cost of CO_2, 2015-2050 (in 2011$)* 4-12

Table 4-3. Estimated Global Climate Benefits of CO_2 Reductions for Proposed EGU GHG Existing Source Guidelines in 2020 (billions of 2011$)* 4-12

Table 4-4. Estimated Global Climate Benefits of CO_2 Reductions for Proposed EGU GHG Existing Source Guidelines in 2025 (billions of 2011$)* 4-12

Table 4-5. Estimated Global Climate Benefits of CO_2 Reductions for Proposed EGU GHG Existing Source Guidelines in 2030 (billions of 2011$)* 4-12

Table 4-6. Human Health Effects of Ambient $PM_{2.5}$ and Ozone 4-17

Table 4-7. Summary of National and Regional Benefit-per-ton Estimates for EGUs in 2020 4-26

Table 4-8. Summary of National and Regional Benefit-per-Ton Estimates for EGUs in 2025 4-26

Table 4-9. Summary of National and Regional Benefit-per-Ton Estimates for EGUs in 2030 4-27

Table 4-10. Emission Reductions of Criteria Pollutants for the Proposed EGU GHG Existing Source Guidelines in 2020 (thousands of short tons)* 4-28

Table 4-11. Emission Reductions of Criteria Pollutants for the Proposed EGU GHG Existing Source Guidelines in 2025 (thousands of short tons)* 4-29

Table 4-12. Emission Reductions of Criteria Pollutants for the Proposed EGU GHG Existing Source Guidelines in 2030 (thousands of short tons)* 4-30

Table 4-13. Summary of Estimated Monetized Health Co-Benefits for the Proposed EGU GHG Existing Source Guidelines in 2020 (millions of 2011$) * 4-31

Table 4-14. Summary of Estimated Monetized Health Co-Benefits for the Proposed EGU GHG Existing Source Guidelines in 2025 (millions of 2011$) * 4-32

Table 4-15. Summary of Estimated Monetized Health Co-Benefits for the Proposed EGU GHG Existing Source Guidelines in 2030 (millions of 2011$) * 4-33

Table 4-16. Summary of Avoided Health Incidences from $PM_{2.5}$-Related and Ozone-Related Co-benefits for Proposed EGU GHG Existing Source Guidelines in 2020*....4-34

Table 4-17. Summary of Avoided Health Incidences from $PM_{2.5}$-Related and Ozone-Related Co-benefits for Proposed EGU GHG Existing Source Guidelines in 2025*....4-35

Table 4-18. Summary of Avoided Health Incidences from $PM_{2.5}$-Related and Ozone-Related Co-Benefits for Proposed EGU GHG Existing Source Guidelines in 2030*....4-36

Table 4-19. Population Exposure in the Baseline Sector Modeling (used to generate the benefit-per-ton estimates) Above and Below Various Concentrations Benchmarks in the Underlying Epidemiology Studies *....4-44

Table 4-20. Combined Climate Benefits and Health Co-Benefits for Proposed EGU GHG Existing Source Guidelines in 2020 (billions of 2011$)*....4-48

Table 4-21. Combined Climate Benefits and Health Co-Benefits for Proposed EGU GHG Existing Source Guidelines in 2025 (billions of 2011$)*....4-49

Table 4-22. Combined Climate Benefits and Health Co-Benefits for Proposed EGU GHG Existing Source Guidelines in 2030 (billions of 2011$)*....4-50

Table 4-23. Unquantified Health and Welfare Co-benefits Categories 4-52

Table 4A-1. Summary of National and Regional Emissions in Sector Modeling for EGUs in 2016 (in short tons)....4A-7

Table 4A-2. Summary of National and Regional $PM_{2.5}$ Benefit-per-Ton Estimates for EGUs in 2020 (2011$)* 4A-11

Table 4A-3. Summary of National and Regional $PM_{2.5}$ Benefit-per-Ton Estimates for EGUs in 2025 (2011$)* 4A-11

Table 4A-4. Summary of National and Regional $PM_{2.5}$ Benefit-per-Ton Estimates for EGUs in 2030 (2011$)* 4A-12

Table 4A-5. Summary of Regional $PM_{2.5}$ Incidence-per-Ton Estimates for EGUs in 2020* 4A-13

Table 4A-6. Summary of Regional $PM_{2.5}$ Incidence-per-Ton Estimates for EGUs in 2025* 4A-14

Table 4A-7. Summary of Regional $PM_{2.5}$ Incidence-per-Ton Estimates for EGUs in 2030* 4A-15

Table 4A-8. Summary of National and Regional Ozone Benefit-per-Ton Estimates for EGUs in 2020 (2011$)* 4A-18

Table 4A-9. Summary of National and Regional Ozone Benefit-per-Ton Estimates for EGUs in 2025 (2011$)* 4A-18

Table 4A-10. Summary of National and Regional Ozone Benefit-per-Ton Estimates for EGUs in 2030 (2011$)* 4A-18

Table 4A-11. Summary of Regional Ozone Incidence-per-Ton Estimates for EGUs in 2020* 4A-19

Table 4A-12. Summary of Regional Ozone Incidence-per-Ton Estimates for EGUs in 2025* 4A-19

Table 4A-13. Summary of Regional Ozone Incidence-per-Ton Estimates for EGUs in 2030* 4A-19

Table 5-1. Estimated Percentage Changes in Average Energy Prices, by Energy Type and Regulatory Option 5-4

Table 6-1. U. S. Green Goods and Services (GGS) Employment (annual average) 6-17

Table 6-2. Renewable Electricity Generation-Related Employment 6-18

Table 6-3. Energy and Resources Efficiency-Related Employment 6-19

Table 6-4. Engineering-Based[a] Changes in Labor Utilization, Regional Compliance Approach - (Number of Job-Years[b] of Employment in a Single Year) 6-26

Table 6-5. Engineering-Based[a] Changes in Labor Utilization, State Compliance Approach (Number of Job-Years of Employment in Year)....................6-27

Table 6-6. Estimated Demand-Side Energy Efficiency Employment Impacts For Option 1 and Option 2 for Both Regional and State Compliance Approaches 6-31

Table 6A-1. Labor Productivity Growth Rate due to Heat Rate Improvement 6A-4

Table 6A-2. Capital Charge Rate and Duration Assumptions 6A-6

Table 6A-3. Expenditure Breakdown due to New Generating Capacity 6A-6

Table 6A-4. Labor Productivity due to New Generating Capacity....................6A-7

Table 6A-5. Average FOM Cost Assumptions....................6A-8

Table 6A-6. Labor Productivity due to New Generating Capacity....................6A-9

Table 7-1. Potentially Regulated Categories and Entities[a]....................7-4

Table 8-1. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits

for the Proposed Guidelines – 2020 (billions of 2011$) [a]....................8-4

Table 8-2. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines – 2025 (billions of 2011$) [a]....................8-5

Table 8-3. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines –2030 (billions of 2011$) [a]....................8-6

Table 9-1. Proposed Emission Limits - Reconstructions....................9-3

Table 9-2. Proposed Emission Limits - Modifications 9-5

Table 9-3. Annualized Costs and Fuel Savings of Efficiency Improvements (millions of 2011$) 9-9

Table 9-4. Emission Reductions from Efficiency Improvements (tons/year) 9-10

Table 9-5. Summary of National Benefit-per-ton (BPT) Estimates for EGUs in 2025 9-10

Table 9-6. Estimated Global Climate Benefits of Illustrative CO_2 Reductions in 2025 (millions of 2011$)* 9-11

Table 9-7. Summary of Estimated Monetized Health Co-benefits of Illustrative Efficiency Improvements in 2025 (thousands of 2011$)* 9-12

Table 9-8. Combined Estimated Climate Benefits and Health Co-Benefits of Illustrative Efficiency Improvements in 2025 (millions of 2011$)* 9-13

LIST OF FIGURES

Figure 2-1. Fossil Fuel-Fired Electricity Generating Facilities, by Size 2-5

Figure 2-2. Status of State Electricity Industry Restructuring Activities 2-8

Figure 2-3. Domestic Emissions of Greenhouse Gases, 2012 (million metric tons of CO_2 equivalent) ...2-9

Figure 2-4. Direct GHG Emissions from the Power Sector Relative to Total Domestic GHG Emissions (2012) 2-11

Figure 2-5. National Average Retail Electricity Price (1960 – 2013, 2011$) 2-20

Figure 2-6. Average Retail Electricity Price by State (cents/kWh), 2011 2-22

Figure 2-7. Natural Gas Spot Price, Annual Average (Henry Hub) 2-25

Figure 2-8. Electricity Growth Rate (3-Year Rolling Average) and Projections from the Annual Energy Outlook 2014 2-26

Figure 3-1. NERC Regions 3-12

Figure 3-2. NERC Assessment Areas 3-12

Figure 3-3. Regional Compliance Zones Used in this Analysis 3-13

Figure 3-4. Generation Mix with the Base Case and 111(d) Options, 2020-2030 (million GWh) 3-28

Figure 3-5. Electricity Market Module Regions 3-43

Figure 4-1. Monetized Health Co-benefits for each Option (Regional Compliance) of the Proposed EGU GHG Existing Source Guidelines in 2020 * 4-37

Figure 4-2. Breakdown of Monetized Health Co-benefits by Precursor Pollutant at a 3% Discount Rate for each Option (Regional Compliance) for Proposed EGU GHG Existing Source Guidelines in 2020* 4-38

Figure 4-3. Breakdown of Monetized Health Co-Benefits by Region at a 3% Discount Rate for each Option (Regional compliance) for Proposed EGU GHG Existing Source Guidelines in 2020* 4-39

Figure 4-4. Percentage of Adult Population (age 30+) by Annual Mean $PM_{2.5}$ Exposure in the Baseline Sector Modeling (used to generate the benefit-per-ton estimates)* 4-45

Figure 4-5. Cumulative Distribution of Adult Population (age 30+) by Annual Mean $PM_{2.5}$ Exposure in the Baseline Sector Modeling (used to generate the benefit-per-ton estimates)* 4-46

Figure 4-6. Breakdown of Combined Monetized Climate and Health Co-benefits of Proposed EGU GHG Existing Source Guidelines in 2020 by Option (Regional Compliance) and Pollutant (3% discount rate)* 4-51

Figure 4A-1. Conceptual Overview of Benefit-per-Ton Calculation 4A-2

Figure 4A-2. Modeled $PM_{2.5}$ Concentrations Attributable to EGUs in 2016 (Annual Mean, in µg/m^3) (Source: BPT TSD) 4A-4

Figure 4A-3. Modeled $PM_{2.5}$ Concentrations Attributable to EGUs by Precursor in 2016 (Annual Mean, in µg/m^3)....................4A-6

Figure 4A-4. Regional Breakdown 4A-7

Figure 4A-5. Breakdown of Directly Emitted $PM_{2.5}$ Emissions from EGU in Sector Modeling....................4A-8

Figure 4A-6. Modeled Average Ozone Concentrations Attributable to EGUs in 2016 (Daily 8-hour maximum, May-September, in ppb)....................4A-17

Figure 4A-7. Comparison of Base Case SO_2 Emissions in 2020....................4A-21

Figure 4A-8. Comparison of Base Case Annual NOx Emissions in 2020....................4A-22

Figure 4A-9. Comparison of Base Case Ozone-season NOx Emissions in 2020....................4A-23

Figure 6.1. Electric Power Industry Employment....................6-12

Figure 6.2. Coal Production Employment 6-14

Figure 6.3. Oil and Gas Production Employment 6-15

ACRONYMS

ACS	American Cancer Society
AEO	Annual Energy Outlook
AQ	Air quality
ASM	Annual Survey of Manufactures
ATSDR	Agency for Toxic Substances and Disease Registry
BACT	Best Available Control Technology
BenMAP	Benefits Mapping and Analysis Program
BPT	Benefit-per-Ton
BSER	Best System of Emissions Reduction
Btu	British Thermal Units
C	Celsius
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration or Carbon Capture and Storage
CCSP	Climate Change Science Program
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CRF	Capital Recovery Factor
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbines
CUA	Climate Uncertainty Adder
DICE	Dynamic Integrated Climate and Economy Model
DOE	U.S. Department of Energy
EAB	Environmental Appeals Board
EC	Elemental carbon
ECS	Energy Cost Share
EG	Emissions guidelines
EGR	Enhanced Gas Recovery

EGU	Electric Generating Unit
EIA	U.S. Energy Information Administration
EMM	Electricity Market Module
EO	Executive Order
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
ER	Enhanced Recovery
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FOAK	First of a Kind
FOM	Fixed Operating and Maintenance
FR	Federal Register
FRCC	Florida Reliability Coordinating Council
FUND	Framework for Uncertainty, Negotiation, and Distribution Model v
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GS	Geologic Sequestration
Gt	Gigaton
H_2S	Hydrogen Sulfide
HAP	Hazardous air pollutant
HCl	Hydrogen chloride
HFC	Hydrofluorocarbons
HIA	Health impact assessment
IARC	International Agency for Research on Cancer
IAM	Integrated Assessment Model
ICR	Information Collection Request
IGCC	Integrated Gasification Combined Cycle
IOU	Investor Owned Utility
IPCC	Intergovernmental Panel on Climate Change
IPM	Integrated Planning Model
IRIS	Integrated Risk Information System
IRP	Integrated Resource Plan
ISA	Integrated Science Assessment

kWh	Kilowatt-hour
lbs	Pounds
LCOE	Levelized Cost of Electricity
LML	Lowest measured level
LNB	Low NO_x Burners
MATS	Mercury and Air Toxics Standards
MEA	Monoethanolamine
MECSA	Manufacturing Energy Consumption Survey
MeHg	Methylmercury
MGD	Millions of Gallons per Day
mg/L	Milligrams per Liter
mmBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NaOH	Sodium Hydroxide
NATCARB	National Carbon Sequestration Database and Geographic Information System
NEEDS	National Electric Energy Data System
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NMMAPS	National Morbidity, Mortality Air Pollution Study
NOAK	Next of a Kind or Nth of a Kind
NO_x	Nitrogen Oxide
NRC	National Research Council
NSPS	New Source Performance Standard
NSR	New Source Review
NTTAA	National Technology Transfer and Advancement Act
OC	Organic carbon
OFA	Overfire Air

OMB	Office of Management and Budget
PAGE	Policy Analysis of the Greenhouse Gas Effect Model
PFC	Perfluorocarbons
$PM_{2.5}$	Fine Particulate Matter
ppm	Parts per Million
PRA	Paperwork Reduction Act
PSD	Prevention of Significant Deterioration
RCSP	Regional Carbon Sequestration Partnerships
RADS	Relative Airways Dysfunction Syndrome
RES	Renewable Electricity Standards
RFA	Regulatory Flexibility Act
RGGI	Regional Greenhouse Gas Initiative
RIA	Regulatory Impact Analysis
RPS	Renewable Portfolio Standards
SAB-CASAC	Science Advisory Board Clean Air Scientific Advisory Committee
SAB-HES	Science Advisory Board Health Effects Subcommittee of the Advisory Council on Clean Air Compliance
SAB-EEAC	Science Advisory Board Environmental Economics Advisory Committee
SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act
SCC	Social Cost of Carbon
SCPC	Super Critical Pulverized Coal
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Tcf	Trillion Cubic Feet
TDS	Total Dissolved Solids
TSD	Technical Support Document
TSM	Transportation Storage and Monitoring
UMRA	Unfunded Mandates Reform Act
U.S.C.	U.S. Code

USGCRP	U.S. Global Change Research Program
USGS	U.S. Geological Survey
USG SCC	U.S. Government's Social Cost of Carbon
U.S. NRC	U.S. Nuclear Regulatory Commission
VCS	Voluntary Consensus Standards
VOC	Volatile Organic Compounds
VOM	Variable Operating and Maintenance
VSL	Value of a statistical life
WTP	Willingness to pay

EXECUTIVE SUMMARY

This Regulatory Impact Analysis (RIA) discusses potential benefits, costs, and economic impacts of the proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units (herein referred to EGU GHG Existing Source Guidelines). This RIA also discusses the potential benefits, costs and economic impacts of the proposed Standards of Performance for Greenhouse Gas Emissions from Reconstructed and Modified Stationary Sources (EGU GHG Reconstructed and Modified Source Standards).

ES.1 Background and Context of Proposed EGU GHG Existing Source Guidelines

Greenhouse gas pollution threatens Americans' health and welfare by leading to long-lasting changes in our climate that can have a range of severely negative effects on human health and the environment. Carbon Dioxide (CO_2) is the primary greenhouse gas pollutant, accounting for nearly three-quarters of global greenhouse gas emissions and 84 percent of U.S. greenhouse gas emissions. Fossil fuel-fired electric generating units (EGUs) are, by far, the largest emitters of GHGs, primarily in the form of CO_2, among stationary sources in the U.S.

In this action, the EPA is proposing emission guidelines for states to use in developing plans to address greenhouse gas emissions from existing fossil fuel-fired EGUs. Specifically, the EPA is proposing state-specific rate-based goals for carbon dioxide emissions from the power sector, as well as emission guidelines for states to use in developing plans to attain the state-specific goals. This rule, as proposed, would set in motion actions to lower the carbon dioxide emissions associated with existing power generation sources in the United States.

ES.2 Summary of Proposed EGU GHG Existing Source Guidelines

Under Clean Air Act (CAA) section 111(d), state plans must establish standards of performance that reflect the degree of emission limitation achievable through the application of the “best system of emission reduction” (BSER) that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements, the Administrator determines has been adequately demonstrated.[1] Consistent with CAA section 111(d), this proposed rule contains state-specific goals that reflect the EPA's calculation of the emission reductions that a state can achieve through the application of BSER. The EPA is using the following four building blocks to determine state-specific goals:

1. Reducing the carbon intensity of generation at individual affected EGUs through heat-rate improvements.
2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including natural gas combined cycle [NGCC] units that are under construction).
3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.
4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

The proposed rule also contains emission guidelines for states to use in developing plans that set their standards of performance. The EPA recognizes that each state has different policy considerations, including varying emission reduction opportunities and existing state programs and measures, and characteristics of the electricity system (e.g., utility regulatory structure, generation mix, electricity demand). The proposed emission guidelines provide states with options for establishing standards of performance in a manner that accommodates a diverse range of state approaches. The proposed guidelines would also allow states to collaborate and to demonstrate emission performance on a multi-state basis, in recognition of the fact that electricity is transmitted across state lines, and local measures often impact regional EGU CO_2

[1] Under CAA sections 111(a)(1) and (d), the EPA is authorized to determine the BSER and to calculate the amount of emission reduction achievable through applying the BSER; and the state is authorized to identify the standard(s) of performance that reflects that amount of emission reduction. In addition, the state is required to include in its state plan the standards of performance and measures to implement and enforce those standards. The state must submit the plan to the EPA, and the EPA must approve the plan if the standards of performance and implementing and enforcing measures are satisfactory.

emissions.

While the EPA must establish BSER and is proposing goals and guidelines that reflect BSER, CAA section 111(d) also provides the EPA with the flexibility to design goals and guidelines that recognize, and are tailored to, the uniqueness and complexity of the power generation sector and CO_2 emissions. And, importantly, CAA section 111(d) allows the states flexibility in designing the measures for their state plans in response to the EPA's guidelines. States are not required to use each of the measures that the EPA determines constitute BSER, or use those measures to the same degree of stringency that the EPA determines is achievable at a reasonable cost; rather, CAA section 111(d) allows each state to determine the appropriate combination of, and the extent of its reliance on, measures for its state plan, by way of meeting its state-specific goal. Given the flexibilities afforded states in complying with the emission guidelines, the benefits, cost and economic impacts reported in this RIA are not definitive estimates, but are instead illustrative of compliance actions states may take.

ES.3 Control Strategies for Existing EGUs

States will ultimately determine approaches to comply with the goals established in this regulatory action. The EPA is proposing a BSER goal approach referred to as Option 1 and taking comment on a second approach referred to as Option 2. Each of these goal approaches use the four building blocks described above at different levels of stringency. Option 1 involves higher deployment of the four building blocks but allows a longer timeframe to comply (2030) whereas Option 2 has a lower deployment over a shorter timeframe (2025).

Table ES-1 shows the proposed state goals for Options 1 and 2. This RIA depicts illustrative rate-based compliance scenarios for the goals set for Options 1 and 2, as well as regional and state compliance approaches for each option. With the state compliance approach, states are assumed to comply with the guidelines by implementing measures solely within the state and emissions rate averaging occurs between affected sources on an intrastate basis only. In contrast under the regional approach, groups of states are assumed to collaboratively comply with the guidelines. States have the discretion of choosing between a regional or state compliance approach, and this RIA reports the economic consequences of compliance under two sets of assumptions: one that assumes all states individually take a rate-based compliance approach and the other that assumes certain groups of states take regional rate-based approaches. The analysis in the illustrative scenarios does not assume that states use any specific policy mechanism to achieve the state goals. The distributions of emissions and electricity generation reflected in the Integrated Planning Model (IPM) analysis of the illustrative scenarios could be achieved by various policy mechanisms. Alternative compliance approaches are also possible. For example, the guidance allows flexibility of compliance, including the possibility of using a mass-based approach. While IPM finds a least cost way to achieve the state goals implemented through the rate-based constraints imposed in the illustrative scenarios, individual states or multi-state regional groups may develop more cost effective approaches to achieve their state goals.

Table ES-1. Proposed State Goals (Adjusted MWh-Weighted-Average Pounds of CO_2 per Net MWh from all Affected Fossil Fuel-Fired EGUs) for Options 1 and 2

State[2]	Option 1		Option 2	
	Interim Goal (2020-2029)	Final Goal (2030 Forward)	Interim Goal (2020-2024)	Final Goal (2025 Forward)
Alabama	1,147	1,059	1,270	1,237
Alaska	1,097	1,003	1,170	1,131
Arizona *	735	702	779	763
Arkansas	968	910	1,083	1,058
California	556	537	582	571
Colorado	1,159	1,108	1,265	1,227
Connecticut	597	540	651	627
Delaware	913	841	1,007	983
Florida	794	740	907	884
Georgia	891	834	997	964
Hawaii	1,378	1,306	1,446	1,417
Idaho	244	228	261	254
Illinois	1,366	1,271	1,501	1,457
Indiana	1,607	1,531	1,715	1,683
Iowa	1,341	1,301	1,436	1,417
Kansas	1,578	1,499	1,678	1,625
Kentucky	1,844	1,763	1,951	1,918
Louisiana	948	883	1,052	1,025

[2] The EPA has not developed goals for Vermont and the District of Columbia because current information indicates those jurisdictions have no affected EGUs. Also, as noted in Chapter 3, EPA is not proposing goals for tribes or U.S. territories at this time.

Table ES-1. Continued

Maine	393	378	418	410
Maryland	1,347	1,187	1,518	1,440
Massachusetts	655	576	715	683
Michigan	1,227	1,161	1,349	1,319
Minnesota	911	873	1,018	999
Mississippi	732	692	765	743
Missouri	1,621	1,544	1,726	1,694
Montana	1,882	1,771	2,007	1,960
Nebraska	1,596	1,479	1,721	1,671
Nevada	697	647	734	713
New Hampshire	546	486	598	557
New Jersey	647	531	722	676
New Mexico *	1,107	1,048	1,214	1,176
New York	635	549	736	697
North Carolina	1,077	992	1,199	1,156
North Dakota	1,817	1,783	1,882	1,870
Ohio	1,452	1,338	1,588	1,545
Oklahoma	931	895	1,019	986
Oregon	407	372	450	420
Pennsylvania	1,179	1,052	1,316	1,270
Rhode Island	822	782	855	840
South Carolina	840	772	930	897
South Dakota	800	741	888	861
Tennessee	1,254	1,163	1,363	1,326
Texas	853	791	957	924
Utah *	1,378	1,322	1,478	1,453
Virginia	884	810	1,016	962
Washington	264	215	312	284
West Virginia	1,748	1,620	1,858	1,817
Wisconsin	1,281	1,203	1,417	1,380
Wyoming	1,808	1,714	1,907	1,869

* Excludes EGUs located in Indian country.

Table ES-2 shows the emission reductions associated with the compliance scenarios for the proposed Option 1 regional and state compliance approaches and Table ES-3 reports emission reductions associated with Option 2. In 2020, the EPA estimates that CO_2 emissions will be reduced by 371 million metric tons under the regional compliance approach and by 383 million metric tons assuming a state specific compliance approach compared to base case levels. CO_2 emission reductions for Option 1 increase to 545 and 555 million metric tons annually in 2030 when compared to the base case emissions for Option 1 regional and state compliance approaches, respectively. Tables ES-2 and ES-3 also show emission reductions for criteria air pollutants.

Table ES-2. Summary of Climate and Air Pollutant Emission Reductions Option 1[1]

	CO_2 (million metric tons)	SO_2 (thousands of tons)	NO_X (thousands of tons)	$PM_{2.5}$ (thousands of tons)
2020 Regional Compliance Approach				
Base Case	2,161	1,476	1,559	212
Proposed Guidelines	1,790	1,184	1,213	156
Emissions Change	-371	-292	-345	-56
2025 Regional Compliance Approach				
Base Case	2,231	1,515	1,587	209
Proposed Guidelines	1,730	1,120	1,166	150
Emissions Change	-501	-395	-421	-59
2030 Regional Compliance Approach				
Base Case	2,256	1,530	1,537	198
Proposed Guidelines	1,711	1,106	1,131	144
Emission Change	-545	-424	-407	-54
2020 State Compliance Approach				
Base Case	2,161	1,476	1,559	212
Proposed Guidelines	1,777	1,140	1,191	154
Emissions Change	-383	-335	-367	-58
2025 State Compliance Approach				
Base Case	2,231	1,515	1,587	209
Proposed Guidelines	1,724	1,090	1,151	146
Emission Change	-506	-425	-436	-63
2030 State Compliance Approach				
Base Case	2,256	1,530	1,537	198
Proposed Guidelines	1,701	1,059	1,109	142
Emissions Change	-555	-471	-428	-56

Source: Integrated Planning Model, 2014.

[1] CO_2 emission reductions are used to estimate the climate benefits of the guidelines. SO_2, NOx, and directly emitted $PM_{2.5}$ emission reductions are relevant for estimating air pollution health co-benefits of the proposed guidelines.

Table ES-3. Summary of Climate and Air Pollutant Emission Reductions Option 2[1]

	CO_2 (million metric tons)	SO_2 (thousands of tons)	NO_X (thousands of tons)	$PM_{2.5}$ (thousands of tons)
2020 Regional Compliance Approach				
Base Case	2,161	1,476	1,559	212
Option 2	1,878	1,231	1,290	166
Emissions Change	-283	-244	-268	-46
2025 Regional Compliance Approach				
Base Case	2,231	1,515	1,587	209
Option 2	1,862	1,218	1,279	165
Emissions Change	-368	-297	-309	-44
2020 State Compliance Approach				
Base Case	2,161	1,476	1,559	212
Option 2	1,866	1,208	1,277	163
Emissions Change	-295	-267	-281	-49
2025 State Compliance Approach				
Base Case	2,231	1,515	1,587	209
Option 2	1,855	1,188	1,271	161
Emissions Change	-376	-327	-317	-48

Source: Integrated Planning Model, 2014.

[1] CO_2 emission reductions are used to estimate the climate benefits of the guidelines. SO_2, NOx, and directly emitted $PM_{2.5}$ emission reductions are relevant for estimating air pollution health co-benefits of the guidelines.

ES.4 Costs of Existing EGU Guidelines

The ‘‘compliance costs’’ of this proposed action are represented in this analysis as the change in electric power generation costs between the base case and illustrative compliance scenario policy cases. The compliance scenario policy cases reflect the pursuit by states of a distinct set of strategies, which are not limited to the technologies and measures included in the BSER to meet the EGU GHG emission guidelines, and include cost estimates for demand side energy efficiency. The compliance assumptions, and therefore the projected “compliance costs” set forth in this analysis, are illustrative in nature and do not represent the full suite of compliance flexibilities states may ultimately pursue.

The EPA projects that the annual incremental compliance cost of the proposed Option 1 ranges from $5.4 to $7.4 billion in 2020 and from $7.3 to $8.8 billion in 2030 ($2011), excluding the costs associated with monitoring, reporting, and recordkeeping. The estimated cost of Option 2 is between $4.2 and $5.4 billion in 2020 and between $4.5 and $5.5 billion in 2025 (2011$). The estimated monitoring, reporting and recordkeeping costs for both options are $68.3 million in 2020, $8.9 million in 2025, and $8.9 million in 2030 (2011$). The annual incremental cost is the projected additional cost of complying with the proposed rule in the year analyzed and includes the net change in the annualized cost of capital investment in new generating sources and heat rate improvements at coal steam facilities,[3] the change in the ongoing costs of operating pollution controls, shifts between or amongst various fuels, demand-side energy efficiency measures, and other actions associated with compliance. Costs for both options are reflected in Table ES-4 below and discussed more extensively in Chapter 3 of this RIA.

Table ES-4. Summary of Illustrative Compliance Costs

	Incremental Cost from Base Case (billions of 2011$)		
	2020	2025	2030
Option 1			
State Compliance	$7.4	$5.5	$8.8
Regional Compliance	$5.4	$4.6	$7.3
Option 2			
State Compliance	$5.4	$5.5	n/a
Regional Compliance	$4.2	$4.5	n/a

Source: Integrated Planning Model, 2014, with post-processing to account for exogenous demand-side management energy efficiency costs. See Chapter 5 of the GHG Abatement Measures TSD for a full explanation. Compliance costs shown here do not include monitoring, reporting, and recordkeeping costs.

The costs reported in Table ES-4 represent the estimated incremental electric utility generating costs changes from the base case, plus end-use energy efficiency program costs (paid by electric utilities) and end-use energy efficiency participant costs (paid by electric utility consumers). For example in 2020 for the proposed Option 1 regional compliance approach, end-use energy efficiency program costs are estimated to be $5.1 billion and end-use efficiency participant costs are $5.1 billion using a 3% discount rate (see Table 3-4). This estimate for end-use energy efficiency costs of $10.2 billion is combined with the costs generated by the IPM that include the costs of states' compliance with state goals associated with changes to reduce the carbon-intensity of electricity production and the energy demand decreases expected from end-use energy efficiency assumed in the illustrative scenarios. In order to reflect the full cost

[3] See Chapter 8 of EPA's Base Case using IPM (v5.13) documentation, available at: http://www.epa.gov/powersectormodeling/BaseCasev513.html

attributable to the policy, it is necessary to include this incremental -$4.8 billion (see Table 3-9) in electricity supply expenditure with the annualized expenditure needed to secure the end-use energy efficiency improvements. As a result, this analysis finds the cost of the Option 1 regional scenario in 2020 to be $5.4 billion (the sum of incremental supply-related and demand-related expenditures). Note that when monitoring, reporting and recordkeeping costs of $68.3 million are added to this estimate, compliance costs become $5.5 billion in 2020.

The compliance costs reported in Table ES-4 are not social costs. These costs represent the illustrative real resources costs for states to comply with the BSER goals for Options 1 and 2. Electric sector compliance costs and monitoring, recordkeeping and reporting costs are compared to social benefits in Tables ES-8, ES-9 and ES-10 to derive illustrative net benefits of the guidelines. For a more extensive discussion of social costs, see Chapter 3 of this RIA.

ES.5 Monetized Climate Benefits and Health Co-benefits for Existing EGUs

Implementing the proposed guidelines is expected to reduce emissions of CO_2 and have ancillary emission reductions (i.e., co-benefits) of SO_2, NO_2, and directly emitted $PM_{2.5}$, which would lead to lower ambient concentrations of $PM_{2.5}$ and ozone. The climate benefits estimates have been calculated using the estimated values of marginal climate impacts presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866*, henceforth denoted as the 2013 SCC TSD.[4] Also, the range of combined benefits reflects different concentration-response functions for the air pollution health co-benefits, but it does not capture the full range of uncertainty inherent in the health co-benefits estimates. Furthermore, we were unable to quantify or monetize all of the climate benefits and health and environmental co-benefits associated with the proposed emission

[4] Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised November 2013). Available at: http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf

guidelines, including reducing exposure to SO_2, NO_x, and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment. These unquantified benefits could be substantial, but it is difficult to approximate the potential magnitude of these unquantified benefits and previous quantification attempts have been incomplete. The omission of these endpoints from the monetized results should not imply that the impacts are small or unimportant. Table ES-5 provides the list of the quantified and unquantified environmental and health benefits in this analysis.

Table ES-5. Quantified and Unquantified Benefits

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Environment				
Reduced climate effects	Global climate impacts from CO_2	—	✓	SCC TSD
	Climate impacts from ozone and black carbon (directly emitted PM)	—	—	Ozone ISA, PM ISA[1]
	Other climate impacts (e.g., other GHGs such as methane, aerosols, other impacts)	—	—	IPCC[1]
Improved Human Health (co-benefits)				
Reduced incidence of premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	✓	✓	PM ISA
	Infant mortality (age <1)	✓	✓	PM ISA
Reduced incidence of morbidity from exposure to $PM_{2.5}$	Non-fatal heart attacks (age > 18)	✓	✓	PM ISA
	Hospital admissions—respiratory (all ages)	✓	✓	PM ISA
	Hospital admissions—cardiovascular (age >20)	✓	✓	PM ISA
	Emergency room visits for asthma (all ages)	✓	✓	PM ISA
	Acute bronchitis (age 8-12)	✓	✓	PM ISA
	Lower respiratory symptoms (age 7-14)	✓	✓	PM ISA
	Upper respiratory symptoms (asthmatics age 9-11)	✓	✓	PM ISA
	Asthma exacerbation (asthmatics age 6-18)	✓	✓	PM ISA
	Lost work days (age 18-65)	✓	✓	PM ISA
	Minor restricted-activity days (age 18-65)	✓	✓	PM ISA
	Chronic Bronchitis (age >26)	—	—	PM ISA[1]
	Emergency room visits for cardiovascular effects (all ages)	—	—	PM ISA[1]
	Strokes and cerebrovascular disease (age 50-79)	—	—	PM ISA[1]
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[2]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[2]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc)	—	—	PM ISA[2,3]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[2,3]
Reduced incidence of mortality from exposure to ozone	Premature mortality based on short-term study estimates (all ages)	✓	✓	Ozone ISA
	Premature mortality based on long-term study estimates (age 30–99)	—	—	Ozone ISA[1]
Reduced incidence of morbidity from exposure to ozone	Hospital admissions—respiratory causes (age > 65)	✓	✓	Ozone ISA
	Hospital admissions—respiratory causes (age <2)	✓	✓	Ozone ISA
	Emergency department visits for asthma (all ages)	✓	✓	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[1]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[2]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[2]
	Reproductive and developmental effects	—	—	Ozone ISA[2,3]

Table ES-5. Continued

Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions (all ages)	—	—	NO_2 ISA[1]
	Chronic lung disease hospital admissions (age > 65)	—	—	NO_2 ISA[1]
	Respiratory emergency department visits (all ages)	—	—	NO_2 ISA[1]
	Asthma exacerbation (asthmatics age 4–18)	—	—	NO_2 ISA[1]
	Acute respiratory symptoms (age 7–14)	—	—	NO_2 ISA[1]
	Premature mortality	—	—	NO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO_2 ISA[2,3]
Reduced incidence of morbidity from exposure to SO_2	Respiratory hospital admissions (age > 65)	—	—	SO_2 ISA[1]
	Asthma emergency department visits (all ages)	—	—	SO_2 ISA[1]
	Asthma exacerbation (asthmatics age 4–12)	—	—	SO_2 ISA[1]
	Acute respiratory symptoms (age 7–14)	—	—	SO_2 ISA[1]
	Premature mortality	—	—	SO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	SO_2 ISA[1,2]
Reduced incidence of morbidity from exposure to methylmercury	Neurologic effects—IQ loss	—	—	IRIS; NRC, 2000[1]
	Other neurologic effects (e.g., developmental delays, memory, behavior)	—	—	IRIS; NRC, 2000[2]
	Cardiovascular effects	—	—	IRIS; NRC, 2000[2,3]
	Genotoxic, immunologic, and other toxic effects	—	—	IRIS; NRC, 2000[2,3]
Reduced incidence of morbidity from exposure to HAP	Effects associated with exposure to hydrogen chloride	—	—	ATSDR, IRIS[1,2]
Improved Environment (co-benefits)				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[1]
	Visibility in residential areas	—	—	PM ISA[1]
Reduced effects on materials	Household soiling	—	—	PM ISA[1,2]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[2]
Reduced PM deposition (metals and organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[2]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[1]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[1]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[1]
	Damage to urban ornamental plants	—	—	Ozone ISA[2]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[1]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[2]
	Other non-use effects			Ozone ISA[2]
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[2]
Reduced effects from acid deposition	Recreational fishing	—	—	NO_x SO_x ISA[1]
	Tree mortality and decline	—	—	NO_x SO_x ISA[2]
	Commercial fishing and forestry effects	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO_x SO_x ISA[2]

Table ES-5. Continued

Reduced effects from nutrient enrichment	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Coastal eutrophication	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NO_x SO_x ISA[2]
Reduced vegetation effects from exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NO_x SO_x ISA[2]
	Injury to vegetation from NO_x exposure	—	—	NO_x SO_x ISA[2]
Reduced ecosystem effects from exposure to methylmercury	Effects on fish, birds, and mammals (e.g., reproductive effects)	—	—	Mercury Study RTC[2]
	Commercial, subsistence and recreational fishing	—	—	Mercury Study RTC[1]

[1] We assess these co-benefits qualitatively due to data and resource limitations for this analysis.

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

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

ES.5.1 Estimating Global Climate Benefits

We estimate the global social benefits of CO_2 emission reductions expected from this rulemaking using the SCC estimates presented in the 2013 SCC TSD. We refer to these estimates, which were developed by the U.S. government, as “SCC estimates” for the remainder of this document. The SCC is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (i.e., benefits of rulemakings that have an incremental impact on cumulative global CO_2 emissions).

The SCC estimates used in this analysis have been developed over many years, using the best science available, and with input from the public. The EPA and other federal agencies have considered the extensive public comments on ways to improve SCC estimation received via the notice and comment period that was part of numerous rulemakings since 2006. In addition, OMB’s Office of Information and Regulatory Affairs recently sought public comment on the approach used to develop the SCC estimates. The comment period ended on February 26, 2014, and OMB is reviewing the comments received.

An interagency process that included the EPA and other executive branch entities used three integrated assessment models (IAMs) to develop SCC estimates and selected four global values for use in regulatory analyses. The SCC estimates represent global measures because of the distinctive nature of the climate change problem. Emissions of greenhouse gases contribute to damages around the world, even when they are released in the United States, and the world's economies are now highly interconnected. Therefore, the SCC estimates incorporate the worldwide damages caused by carbon dioxide emissions in order to reflect the global nature of the problem, and we expect other governments to consider the global consequences of their greenhouse gas emissions when setting their own domestic policies. See RIA Chapter 4 for more discussion.

The federal government first released the estimates in February 2010 and updated them in 2013 using new versions of each IAM. The general approach to estimating the SCC values in 2010 and 2013 was to run the three integrated assessment models (DICE, FUND, and PAGE)[5] using the following three inputs in each model: a probabilistic distribution for climate sensitivity; five scenarios capturing economic, population, and emission trajectories; and constant annual discount rates. The 2010 SCC Technical Support Document (SCC TSD) provides a complete discussion of the methodology and the 2013 SCC TSD presents and discusses the updated estimates. The four SCC estimates, updated in 2013, are as follows: $13, $46, $68, and $137 per metric ton of CO_2 emissions in the year 2020 (2011$), and each estimate increases over time. These SCC estimates are associated with different discount rates. The first three estimates are the model average at 5 percent discount rate, 3 percent, and 2.5 percent, respectively, and the fourth estimate is the 95th percentile at 3 percent.

The 2010 SCC TSD noted a number of limitations to the SCC analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their

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[5] The full models names are as follows: Dynamic Integrated Climate and Economy (DICE); Climate Framework for Uncertainty, Negotiation, and Distribution (FUND); and Policy Analysis of the Greenhouse Gas Effect (PAGE).

incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Current integrated assessment models do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. In particular, the IPCC Fourth Assessment Report concluded that "It is very likely that [SCC estimates] underestimate the damage costs because they cannot include many non-quantifiable impacts." Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 emission reductions to inform the benefit-cost analysis.

ES 5.2 Estimating Air Pollution Health Co-Benefits

The proposed guidelines would reduce emissions of precursor pollutants (e.g., SO_2, NOx, and directly emitted particles), which in turn would lower ambient concentrations of $PM_{2.5}$ and ozone. This co-benefits analysis quantifies the monetized benefits associated with the reduced exposure to these two pollutants.[6] Unlike the global SCC estimates, the air pollution health co-benefits are only estimated for the contiguous U.S.[7] The estimates of monetized $PM_{2.5}$ co-benefits include avoided premature deaths (derived from effect coefficients in two cohort studies [Krewski et al. 2009 and Lepeule et al. 2012] for adults and one for infants [Woodruff et al. 1997]), as well as avoided morbidity effects for ten non-fatal endpoints ranging in severity from lower respiratory symptoms to heart attacks (U.S. EPA, 2012). The estimates of monetized ozone co-benefits include avoided premature deaths (derived from the range of effect coefficients represented by two short-term epidemiology studies [Bell et al. (2004) and Levy et al. (2005)]), as well as avoided morbidity effects for five non-fatal endpoints ranging in severity from school absence days to hospital admissions (U.S. EPA, 2008, 2011).

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[6] We did not estimate the co-benefits associated with reducing direct exposure to SO_2 and NOx.

[7] We do not have emission reduction information or air quality modeling available to estimate the air pollution health co-benefits in Alaska and Hawaii anticipated from implementation of the proposed guidelines.

We used a "benefit-per-ton" approach to estimate the health co-benefits. To create the benefit-per-ton estimates for $PM_{2.5}$, this approach uses an air quality model to convert emissions of $PM_{2.5}$ precursors (e.g., SO_2, NO_x) and directly emitted particles into changes in ambient $PM_{2.5}$ concentrations and BenMAP to estimate the changes in human health associated with that change in air quality. We then divide these health impacts by the emissions in specific sectors at the regional level (i.e., East, West, and California). We followed a similar process to estimate benefit-per-ton estimates for the ozone precursor NO_x. To calculate the co-benefits for the proposed guidelines, we then multiplied the regional benefit-per-ton estimates for the EGU sector by the corresponding emission reductions. All benefit-per-ton estimates reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions in this rulemaking, and thus they may not reflect the local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location.

Our estimate of the monetized co-benefits is based on the EPA's interpretation of the best available scientific literature (U.S. EPA, 2009) and methods and supported by the EPA's Science Advisory Board and the NAS (NRC, 2002). Below are key assumptions underlying the estimates for $PM_{2.5}$-related premature mortality, which accounts for 98 percent of the monetized $PM_{2.5}$ health co-benefits:

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

2. We assume that the health impact function for fine particles is log-linear without a threshold in this analysis. Thus, the estimates include health co-benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both

areas that do not meet the fine particle standard and those areas that are in attainment, down to the lowest modeled concentrations.

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

Every benefits analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe this analysis provides a reasonable indication of the expected health co-benefits of the air pollution emission reductions for the illustrative compliance options for the proposed standards under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates.

ES 5.3 Combined Benefits Estimates

The EPA has evaluated the range of potential impacts by combining all four SCC values with health co-benefits values at the 3 percent and 7 percent discount rates. Different discount rates are applied to SCC than to the health co-benefit estimates; because CO_2 emissions are long-lived and subsequent damages occur over many years. Moreover, several discount rates are applied to SCC because the literature shows that the estimate of SCC is sensitive to assumptions about discount rate and because no consensus exists on the appropriate rate to use in an intergenerational context. The U.S. government centered its attention on the average SCC at a 3 percent discount rate but emphasized the importance of considering all four SCC estimates.

Tables ES-6 and ES-7 provide the combined climate benefits and health co-benefits for each option evaluated for 2020, 2025 and 2030 for Options 1 and 2, respectively for each discount rate combination.

Table ES-6. Combined Estimates of Climate Benefits and Health Co-Benefits for Proposed Existing EGU GHG Rule – Regional Compliance Approach (billions of 2011$)*

Option	SCC Discount Rate and Statistic**	Climate Benefits Only	Climate Benefits plus Health Co-Benefits (Discount Rate Applied to Health Co-Benefits) 3%			7%		
Option 1	In 2020	371	million metric tonnes CO_2					
	5%	$4.7	$21	to	$42	$19	to	$39
	3%	$17	$33	to	$54	$32	to	$51
	2.5%	$25	$41	to	$63	$40	to	$59
	3% (95th percentile)	$51	$67	to	$88	$65	to	$85
	In 2025	501	million metric tonnes CO_2					
	5%	$7.5	$30	to	$61	$28	to	$56
	3%	$25	$48	to	$78	$46	to	$74
	2.5%	$37	$60	to	$90	$57	to	$85
	3% (95th percentile)	$76	$99	to	$130	$97	to	$120
	In 2030	545	million metric tonnes CO_2					
	5%	$9.3	$35	to	$68	$32	to	$63
	3%	$30	$55	to	$89	$53	to	$84
	2.5%	$44	$69	to	$100	$66	to	$97
	3% (95th percentile)	$92	$120	to	$150	$120	to	$150
Option 2	In 2020	283	million metric tonnes CO_2					
	5%	$3.6	$17	to	$34	$16	to	$32
	3%	$13	$26	to	$44	$25	to	$41
	2.5%	$19	$33	to	$50	$31	to	$47
	3% (95th percentile)	$39	$52	to	$70	$51	to	$67
	In 2025	368	million metric tonnes CO_2					
	5%	$5.5	$23	to	$46	$21	to	$42
	3%	$18	$36	to	$59	$34	to	$55
	2.5%	$27	$44	to	$67	$43	to	$64
	3% (95th percentile)	$56	$73	to	$96	$72	to	$93

*All benefit estimates are rounded to two significant figures. Climate benefits are based on reductions in CO_2 emissions. Co-benefits are based on regional benefit-per-ton estimates. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski et al. (2009) with Bell et al. (2004) to Lepeule et al. (2012) with Levy et al. (2005)). The monetized health co-benefits do not include reduced health effects from direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment. See Chapter 4 for more information about these estimates and regarding the uncertainty in these estimates.
**Unless otherwise specified, it is the model average.

Table ES-7. Combined Estimates of Climate Benefits and Health Co-Benefits for Proposed Existing EGU GHG Rule – State Compliance Approach (billions of 2011$)*

Option	SCC Discount Rate and Statistic**	Climate Benefits Only	Climate Benefits plus Health Co-Benefits (Discount Rate Applied to Health Co-Benefits)					
			3%			7%		
Option 1	In 2020	383	million metric tonnes CO_2					
	5%	$4.9	$22	to	$45	$20	to	$41
	3%	$18	$35	to	$57	$33	to	$54
	2.5%	$26	$43	to	$66	$42	to	$62
	3% (95th percentile)	$52	$69	to	$92	$68	to	$88
	In 2025	506	million metric tonnes CO_2					
	5%	$7.6	$31	to	$62	$29	to	$57
	3%	$25	$49	to	$80	$46	to	$75
	2.5%	$37	$61	to	$92	$58	to	$87
	3% (95th percentile)	$77	$100	to	$130	$98	to	$130
	In 2030	555	million metric tonnes CO_2					
	5%	$9.5	$36	to	$72	$34	to	$66
	3%	$31	$57	to	$93	$55	to	$87
	2.5%	$44	$71	to	$110	$69	to	$100
	3% (95th percentile)	$94	$120	to	$160	$120	to	$150
Option 2	In 2020	295	million metric tonnes CO_2					
	5%	$3.8	$17	to	$35	$16	to	$32
	3%	$14	$27	to	$45	$26	to	$42
	2.5%	$20	$34	to	$52	$32	to	$49
	3% (95th percentile)	$40	$54	to	$72	$53	to	$69
	In 2025	376	million metric tonnes CO_2					
	5%	$5.6	$23	to	$47	$22	to	$43
	3%	$19	$36	to	$60	$35	to	$56
	2.5%	$28	$45	to	$69	$44	to	$65
	3% (95th percentile)	$57	$75	to	$98	$73	to	$95

*All benefit estimates are rounded to two significant figures. Climate benefits are based on reductions in CO_2 emissions. Co-benefits are based on regional benefit-per-ton estimates. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski et al. (2009) with Bell et al. (2004) to Lepeule et al. (2012) with Levy et al. (2005)). The monetized health co-benefits do not include reduced health effects from direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment. See Chapter 4 for more information about these estimates and regarding the uncertainty in these estimates.

**Unless otherwise specified, it is the model average.

ES.6 Monetized Benefits, Compliance Costs and Net Benefits of the Proposed Guidelines for Existing Sources

In this summary, the EPA provides the estimates of the climate benefits, health co-benefits, compliance costs and net benefits of the proposed Option 1 and alternative Option 2 assuming a regional compliance approach and an alternative state compliance approach. In Table

ES-8, the EPA estimates that in 2020 the proposed Option 1 regional compliance approach will yield monetized climate benefits of $17 billion using a 3 percent discount rate (model average, 2011$). The air pollution health co-benefits in 2020 are estimated to be $16 billion to $37 billion (2011$) for a 3 percent discount rate and $15 billion to $34 billion (2011$) for a 7 percent discount rate. The annual compliance costs, including monitoring and reporting costs, are approximately $5.5 billion (2011$) in 2020. The quantified net benefits (the difference between monetized benefits and costs) are $28 billion to $49 billion (2011$) for 2020 (Table ES-8 below) and $48 billion to $82 billion (2011$) for 2030 (Table ES-10 below), using a 3 percent discount rate (model average). For the Option 1 state compliance approach in 2020, the EPA estimates monetized climate benefits of approximately $18 billion using a 3 percent discount rate (model average). The air pollution health co-benefits in 2020 are estimated to be $17 billion to $40 billion for a 3 percent discount rate and $15 billion to $36 billion (2011$) for a 7 percent discount rate. The annual compliance costs including monitoring and reporting costs, are approximately $7.5 billion (2011$) in 2020. The quantified net benefits (the difference between monetized benefits and costs) are $27 billion to $50 billion for 2020 (Table ES-8 below) and $49 billion to $84 billion (2011$) for 2030 (Table ES-10 below). Benefit and cost estimates for Option 1 regional and state compliance approaches for 2020, 2025, and 2030 and are presented in Tables ES-8, ES-9, and ES-10, and similar estimates for Option 2 regional and state compliance approaches are presented in Tables ES-8 and ES-9 for 2020 and 2025.

The EPA could not monetize some important benefits of the guidelines. Unquantified benefits include climate benefits from reducing emissions of non-CO_2 greenhouse gases and co-benefits from reducing exposure to SO_2, NO_x, and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment. Upon considering these limitations and uncertainties, it remains clear that the benefits of this proposal are substantial and far outweigh the costs.

Table ES-8. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines – 2020 (billions of 2011$) [a]

	Option 1 - state		Option 2 – state	
	3% Discount Rate	7% Discount Rate	3% Discount Rate	7% Discount Rate
Climate Benefits [b]				
5% discount rate	$4.9		$3.8	
3% discount rate	$18		$14	
2.5% discount rate	$26		$20	
95th percentile at 3% discount rate	$52		$40	
Air pollution health co-benefits [c]	$17 to $40	$15 to $36	$14 to $32	$12 to $29
Total Compliance Costs [d]	$7.5		$5.5	
Net Benefits [e]	$27 to $50	$26 to $46	$22 to $40	$20 to $37
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 1.5 tons of Hg Ecosystem Effects Visibility impairment		Direct exposure to SO_2 and NO_2 1.2 tons of Hg Ecosystem Effects Visibility impairment	
	Option 1 - regional		Option 2 – regional	
	3% Discount Rate	7% Discount Rate	3% Discount Rate	7% Discount Rate
Climate Benefits [b]				
5% discount rate	$4.7		$3.6	
3% discount rate	$17		$13	
2.5% discount rate	$25		$19	
95th percentile at 3% discount rate	$51		$39	
Air pollution health co-benefits [c]	$16 to $37	$15 to $34	$13 to $31	$12 to $28
Total Compliance Costs [d]	$5.5		$4.3	
Net Benefits [e]	$28 to $49	$26 to $45	$22 to $40	$21 to $37
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 1.3 tons of Hg Ecosystem effects Visibility impairment		Direct exposure to SO_2 and NO_2 0.9 tons of Hg Ecosystem effects Visibility impairment	

[a] All estimates are for 2020 and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimates in this summary table reflect global impacts from CO_2 emission changes and do not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume 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.

[d] Total social costs are approximated by the illustrative compliance costs which, in part, are estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5%. This estimate also includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SCC at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

Table ES-9. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines – 2025 (billions of 2011$) [a]

	Option 1 – state		Option 2 – state	
	3% Discount Rate	7% Discount Rate	3% Discount Rate	7% Discount Rate
Climate Benefits [b]				
5% discount rate	$7.6		$5.6	
3% discount rate	$25		$19	
2.5% discount rate	$37		$28	
95th percentile at 3% discount rate	$77		$57	
Air pollution health co-benefits [c]	$23 to $54	$21 to $49	$18 to $41	$16 to $37
Total Compliance Costs [d]	$5.5		$5.5	
Net Benefits [e]	$43to $74	$41 to $69	$31 to $55	$29 to $51
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 2.0 tons of Hg Ecosystem Effects Visibility impairment		Direct exposure to SO_2 and NO_2 1.7 tons of Hg Ecosystem Effects Visibility impairment	
	Option 1 – regional		Option 2 – regional	
	3% Discount Rate	7% Discount Rate	3% Discount Rate	7% Discount Rate
Climate Benefits [b]				
5% discount rate	$7.5		$5.5	
3% discount rate	$25		$18	
2.5% discount rate	$37		$27	
95th percentile at 3% discount rate	$76		$56	
Air pollution health co-benefits [c]	$23 to $53	$21 to $48	$17 to $40	$16 to $36
Total Compliance Costs [d]	$4.6		$4.5	
Net Benefits [e]	$43 to $74	$41 to $69	$31 to $54	$29 to $50
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 1.7 tons of Hg Ecosystem effects Visibility impairment		Direct exposure to SO_2 and NO_2 1.3 tons of Hg Ecosystem effects Visibility impairment	

[a] All estimates are for 2025 and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimates in this summary table reflect global impacts from CO_2 emission changes and do not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume 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.

[d] Total social costs are approximated by the illustrative compliance costs which, in part, are estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5%. This estimate also includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SCC at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

Table ES-10. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines –2030 (billions of 2011$) [a]

	Option 1– state	
	3% Discount Rate	7% Discount Rate
Climate Benefits [b]		
5% discount rate	$9.5	
3% discount rate	$31	
2.5% discount rate	$44	
95th percentile at 3% discount rate	$94	
Air pollution health co-benefits [c]	$27 to $62	$24 to $56
Total Compliance Costs [d]	$8.8	
Net Benefits [e]	$49 to $84	$46 to $79
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 2.1 tons of Hg and 590 tons of HCl Ecosystem effects Visibility impairment	
	Option 1– regional	
	3% Discount Rate	7% Discount Rate
Climate Benefits [b]		
5% discount rate	$9.3	
3% discount rate	$30	
2.5% discount rate	$44	
95th percentile at 3% discount rate	$92	
Air pollution health co-benefits [c]	$25 to $59	$23 to $54
Total Compliance Costs [d]	$7.3	
Net Benefits [e]	$48 to $82	$46 to $77
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 1.7 tons of Hg and 580 tons of HCl Ecosystem effects Visibility impairment	

[a] All estimates are for 2030, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimates in this summary table reflect global impacts from CO_2 emission changes and do not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume 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.

[d] Total social costs are approximated by the illustrative compliance costs which, in part, are estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5%. This estimate also includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SCC at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

ES.7 Economic Impacts of the Proposed Emission Guidelines for Existing EGUs

The proposed guidelines have important energy market implications. Under Option 1, average nationwide retail electricity prices are projected to increase roughly 6 to 7 percent in 2020, and roughly 3 percent in 2030 (contiguous U.S.), compared to base case price estimates modeled for these same years. Average monthly electricity bills are anticipated to increase by roughly 3 percent in 2020, but decline by roughly 9 percent by 2030 because increased energy efficiency will lead to reduced usage.

The average delivered coal price to the power sector is projected to decrease by 16 to 17 percent in 2020 and roughly 18 percent in 2030, relative to the base case (Option 1). The EPA projects coal production for use by the power sector, a large component of total coal production, will decline by roughly 25 to 27 percent in 2020 from base case levels. The use of coal by the power sector will decrease by roughly 30 to 32 percent in 2030.

The EPA also projects that the electric power sector-delivered natural gas prices will increase by 9 to 12 percent in 2020, with negligible changes by 2030 relative to the base case. Natural gas use for electricity generation will increase by as much as 1.2 trillion cubic feet (TCF) in 2020 relative to the base case, declining over time.

Renewable energy capacity is anticipated to increase by roughly 12 GW in 2020 and by 9 GW in 2030 under Option 1. Energy market impacts from the guidelines are discussed more extensively in Chapter 3 of this RIA.

ES.8 Economic Impacts of the Proposed Guidelines for Existing EGUs for Sectors Other Than the EGU Sector and for Employment

Changes in supply or demand for electricity, natural gas, and coal can impact markets for goods and services produced by sectors that use these energy inputs in the production process or that supply those sectors. Changes in cost of production may result in changes in price and/or quantity produced and these market changes may affect the profitability of firms and the economic welfare of their consumers. The EPA recognizes that these guidelines provide significant flexibilities and states implementing the guidelines may choose to mitigate impacts to some markets outside the EGU sector. Similarly, demand for new generation or energy efficiency can result in changes in production and profitability for firms that supply those goods and services. The guidelines provide flexibility for states that may want to enhance demand for goods and services from those sectors.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, "our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science" (Executive Order 13563, 2011). Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, during periods of sustained high unemployment, employment impacts are of particular concern and questions may arise about their existence and magnitude.

States have the responsibility and flexibility to implement policies and practices for compliance with Proposed Electric Generating Unit Greenhouse Gas Existing Source Guidelines. Given the wide range of approaches that may be used, quantifying the associated employment impacts is difficult. The EPA's illustrative employment analysis includes an estimate of projected employment impacts associated with these guidelines for the electric power industry, coal and natural gas production, and demand side energy efficiency activities. These projections are derived, in part, from a detailed model of the electricity production sector used for this regulatory analysis, and U.S government data on employment and labor productivity. In the electricity, coal, and natural gas sectors, the EPA estimates that these guidelines could result in an increase of approximately 28,000 to 25,900 job-years in 2020 for Option 1, state and regional compliance approaches, respectively. For Option 2, the state and regional compliance approach estimates reflect an increase of approximately 29,800 to 26,700 job-years in 2020. The Agency is also offering an illustrative calculation of potential employment effects due to demand-side energy efficiency programs. Employment impacts in 2020 could be an increase of approximately 78,800 jobs for Option 1 (for both the state and regional compliance approaches). For Option 2 demand-side energy efficiency employment impacts in 2020 could be an increase of approximately 57,000 jobs (for both the state and regional compliance approaches). More detail about these analyses can be found in Chapter 6 of this RIA.

ES.9 Modified and Reconstructed Sources

The EPA is proposing emission limits for CO_2 emitted from reconstructed and modified EGUs under section 111(b) of the CAA. Based on historical information that has been reported to the EPA, the EPA anticipates few, if any, covered units will trigger the reconstruction or modification provisions in the period of analysis (through 2025). As a result, we do not anticipate any significant costs or benefits associated with this proposal. However, because there have been a few units that have notified the EPA of modifications in the past, in Chapter 9 of this RIA we present an illustrative analysis of the costs and benefits for a hypothetical unit if it were to trigger the modification provision.

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CHAPTER 1: INTRODUCTION AND BACKGROUND

1.1 Introduction

This document presents the expected benefits, costs, and economic impacts of illustrative strategies states may implement to comply with the proposed Electric Utility Generating Unit (EGU) Existing Source GHG Guidelines in 2020, 2025, and 2030. Furthermore, this document provides a separate description of the expected benefits, costs, and economic impacts of proposed emission limits for reconstructed and modified EGU sources. This chapter contains background information on these rules and an outline of the chapters in the report.

1.2 Legal, Scientific and Economic Basis for this Rulemaking

1.2.1 Statutory Requirement

Section 111 of the Clean Air Act (CAA) requires performance standards for air pollutant emissions from categories of stationary sources that may reasonably contribute to endangerment of public health or welfare. In April 2007, the Supreme Court ruled in *Massachusetts* v. the *Environmental Protection Agency* (EPA) that greenhouse gases (GHGs) meet the definition of an "air pollutant" under the CAA. This ruling clarified that the authorities and requirements of the CAA apply to GHGs. As a result, the EPA must make decisions about whether to regulate GHGs under certain provisions of the CAA, based on relevant statutory criteria. The EPA issued a final determination that GHG emissions endanger both the public health and the public welfare of current and future generations in the Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the CAA (74 FR 66,496; Dec. 15, 2009).

Section 111(b) authorizes the EPA to issue new source performance standards (NSPS) for carbon dioxide (CO_2) from newly constructed, reconstructed, and modified sources. In January 2014, under the authority of CAA section 111(b), the EPA proposed standards for emissions of CO_2 from newly constructed fossil fuel-fired electric steam generating units (utility boilers and integrated gasification combined cycle [IGCC] units) and for natural gas-fired stationary combustion turbines. The EPA is currently proposing standards to address CO_2 emissions from reconstructed and modified power plants under the authority of CAA section 111(b).

Furthermore, when the EPA establishes section 111(b) standards of performance for newly constructed sources in a particular source category for a pollutant that is not regulated as a criteria pollutant or hazardous air pollutant, the EPA must establish requirements for existing sources in that source category for that pollutant under section 111(d). Under 111(d), the EPA develops "emission guidelines" that the states must develop plans to meet. The EPA is proposing state goals for GHG emissions from existing sources under section 111(d) of the CAA.

1.2.2 Health and Welfare Impacts from Climate Change

In 2009, the EPA Administrator found "six greenhouse gases taken in combination endanger both the public health and the public welfare."[8] These adverse impacts make it necessary for the EPA to regulate GHGs from EGU sources. This proposed rule is designed to reduce the rate at which atmospheric concentrations of these gases are increasing, and therefore reduce the risk of adverse effects.

A number of major peer-reviewed scientific assessments have been released since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial. The EPA has reviewed these assessments and finds that in general, the improved understanding of the climate system they present are consistent with the assessments underlying the 2009 Endangerment Finding. For example, the recently released National Climate Assessment stated, "Climate change is already affecting the American people in far reaching ways. Certain types of extreme weather events with links to climate change have become more frequent and/or intense, including prolonged periods of heat, heavy downpours, and, in some regions, floods and droughts. In addition, warming is causing sea level to rise and glaciers and Arctic sea ice to melt, and oceans are becoming more acidic as they absorb carbon dioxide. These and other aspects of climate change are disrupting people's lives and damaging some sectors of our economy." This and other assessments are outlined in Chapter 4 of this Regulatory Impact Assessment (RIA).

[8] Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act.

1.2.3 Market Failure

Many regulations are promulgated to correct market failures, which 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.

GHG 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 good produced is electricity. These social costs associated with the health and welfare impacts are referred to as negative externalities. If an electricity producer pollutes the atmosphere when it generates electricity, this cost will be borne not by the polluting firm but by society as a whole. The market price of electricity will fail to incorporate the full opportunity cost to society of generating electricity. All else equal, given this externality, the quantity of electricity generated in a free market will not be at the socially optimal level. More electricity will be produced than would occur if the power producers had to account for the full opportunity cost of production including the negative externality. Consequently, absent a regulation on emissions, the marginal social cost of the last unit of electricity produced will exceed its marginal social benefit.

1.3 Summary of Regulatory Analysis

In accordance with Executive Order 12866, Executive Order 13563, and the EPA’s “Guidelines for Preparing Economic Analyses,” the EPA prepared this RIA for this “significant regulatory action.” This action is an economically significant regulatory action because it is expected to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities.

This RIA addresses the potential costs, emission reductions, and benefits of the existing source emission guidelines that are the focus of this action. Additionally, this RIA includes information on potential impacts on electricity markets, employment, and markets outside the electricity sector. Chapter 9 of this document provides a separate description of the expected benefits, costs and economic impacts of proposed emission limits for reconstructed and modified EGU sources.

In evaluating the impacts of the proposed guidelines, we analyzed a number of uncertainties. For example, the analysis includes an evaluation of different potential spatial approaches to state compliance (i.e., state and regional) and in the estimated benefits of reducing carbon dioxide and other air pollutants. For a further discussion of key evaluations of uncertainty in the regulatory analyses for this proposed rulemaking, see Chapter 8 of this RIA.

1.4 Background for the Proposed EGU Existing Source GHG Guidelines

1.4.1 Base Case and Years of Analysis

The rule on which the majority of the analysis in this RIA is based proposes GHG emission guidelines for states to limit CO_2 emissions from certain existing EGUs. The base case for this analysis, which uses the Integrated Planning Model (IPM), includes state rules that have been finalized and/or approved by a state's legislature or environmental agencies, as well as final federal rules. The IPM Base Case v.5.13 includes the Clean Air Interstate Rule (CAIR),[9] the Mercury and Air Toxics Rule (MATS), and other state and Federal regulations to the extent that they contain measures, permits, or other air-related limitations or requirements. Additional legally binding and enforceable commitments for GHG reductions considered in the base case are discussed in the documentation for IPM.[10]

Costs and benefits are presented for compliance in 2020, 2025, and 2030 for Option 1 and 2020 and 2025 for Option 2. These years were selected because they represent partial and

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[9] EPA Base Case v.5.13 includes the Clean Air Interstate Rule (CAIR), a Federal regulatory measure for achieving the 1997 National Ambient Air Quality Standards (NAAQS) for ozone (8-hour average of 0.08 ppm) and fine particles (24-hour average of 65 $\mu g/m^3$ or less and annual average of 15 $\mu g/m^3$ for particles of diameter 2.5 micrometers or less, i.e., PM2.5). Originally issued on March 10, 2005, CAIR was remanded back to EPA by the U.S. Court of Appeals for the District of Columbia Circuit in December 2008 and EPA was required to correct legal flaws in the regulations that had been cited in a ruling by the Court in July 2008. CAIR remains in effect until replaced by EPA pursuant to the Court's ruling. CAIR's provisions were still in effect when EPA Base Case v.5.13 was released.

[10] See Chapter 3 of EPA's Base Case using IPM (v5.13) documentation, available at: http://www.epa.gov/powersectormodeling/BaseCasev513.html

full implementation dates for the two policy options analyzed. Analysis of employment impacts is presented for compliance in 2020, 2025, and 2030 for Option 1 and 2020 and 2025 for Option 2. All estimates are presented in 2011 dollars.

1.4.2 Definition of Affected Sources

This proposed rule under CAA section 111(d) will set emission guidelines for states to limit CO_2 emissions from certain existing EGUs. This rulemaking does not address GHG emissions from newly constructed sources or sources modifying or reconstructing. Section 111(b) emission limits for reconstructed and modified sources are being proposed in a separate action and are discussed in Chapter 9 of this RIA.

For the purposes of this proposed rule, an affected EGU is any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014, and is therefore an "existing source" for purposes of CAA section 111, but in all other respects would meet the applicability criteria for coverage under the proposed GHG standards for newly constructed fossil fuel-fired EGUs published in the Federal Register on that date. The proposed GHG standards for newly constructed EGUs generally define an affected EGU as any boiler, IGCC, or combustion turbine (in either simple cycle or combined cycle configuration) that (1) is capable of combusting at least 250 million British thermal units (Btu) per hour; (2) combusts fossil fuel for more than 10 percent of its total annual heat input; (3) sells the greater of 219,000 MWh per year or one-third of its potential electrical output to a utility distribution system; and (4) was not in operation or under construction as of January 8, 2014 (the date the proposed GHG standards of performance for newly constructed EGUs were published in the Federal Register). The minimum fossil fuel consumption condition applies over any consecutive three-year period (or as long as the unit has been in operation, if less). The minimum electricity sales condition applies over rolling three-year periods (or as long as the unit has been in operation, if less).

1.4.3 Regulated Pollutant

This rule sets emission guidelines for CO_2 emissions from affected sources. The EPA is proposing these guidelines because CO_2 is a GHG and fossil fuel-fired power plants are the country's largest stationary source emitters of GHGs. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.[11]

The EPA is aware that other GHGs such as nitrous oxide (N_2O) (and to a lesser extent, methane [CH_4]) may be emitted from fossil-fuel-fired EGUs, especially from coal-fired circulating fluidized bed combustors and from units with selective catalytic reduction and selective non-catalytic reduction systems installed for nitrogen oxide (NO_X) control. The EPA is not proposing separate N_2O or CH_4 guidelines or an equivalent CO_2 emission limit because of a lack of available data for these affected sources. Additional information on the quantity and significance of emissions and on the availability of controls of reasonable cost would be needed before proposing standards for these pollutants.

1.4.4 Emission Guidelines

The EPA is proposing emission guidelines for states to use in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for CO_2 emissions from the power sector, as well as guidelines for states to follow in developing plans to attain the state-specific goals. (These state-based goals can be found in the preamble and Chapter 3 of this RIA.) The proposed emission guidelines provide states with options for establishing standards of performance in a manner that accommodates a diverse range of state approaches. The proposed guidelines would also allow states to collaborate and to demonstrate compliance on a multi-state basis, in recognition of the fact that electricity is transmitted across state lines, and measures often impact regional EGU CO_2 emissions. The illustrative compliance strategies presented in this RIA include both regional and state-level compliance scenarios for each of the regulatory options presented.

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[11] Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act.

1.5 Organization of the Regulatory Impact Analysis

This report presents the EPA's analysis of the potential benefits, costs, and other economic effects of the proposed EGU Existing Source GHG Guidelines to fulfill the requirements of an RIA. This RIA includes the following chapters:

- Chapter 2, Electric Power Sector Profile
- Chapter 3, Control Strategies, Cost, Economic, and Energy Impacts
- Chapter 4, Estimated Climate Benefits and Health Co-benefits
- Chapter 5, Economic Impacts – Markets Outside the Electricity Sector
- Chapter 6, Employment
- Chapter 7, Statutory and Executive Order Analyses
- Chapter 8, Summary of Benefits and Cost of the Proposed Regulation
- Chapter 9, Benefits, Costs, and Economic Impacts of Standards of Performance for Modified and Reconstructed Electric Generating Units

1.6 References

40 CFR Chapter I [EPA–HQ–OAR–2009–0171; FRL–9091–8] RIN 2060–ZA14, "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act," Federal Register / Vol. 74, No. 239 / Tuesday, December 15, 2009 / Rules and Regulations.

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CHAPTER 2: ELECTRIC POWER SECTOR PROFILE

2.1 Introduction

This chapter discusses important aspects of the power sector that relate to the proposed EGU Existing Source GHG Standards, including the types of power-sector sources affected by the proposal, and provides background on the power sector and EGUs. In addition, this chapter provides some historical background on the EPA regulation of, and future projections for, the power sector.

2.2 Power Sector Overview

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

2.2.1 Generation

Electricity generation is the first process in the delivery of electricity to consumers. Most of the existing capacity for generating electricity does so by creating heat to create high pressure steam that is released to rotate turbines which, in turn, create electricity. The existing power sector consists of over 18,000 generating units, comprising fossil-fuel-fired units, nuclear units, and hydroelectric and other renewable sources dispersed throughout the country (see Table 2-1).

Table 2-1. Existing Electricity Generating Capacity by Energy Source, 2012

Energy Source	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
Coal	1,309	336,341	309,680	312,293
Petroleum	3,702	53,789	47,167	51,239
Natural Gas	5,726	485,957	422,364	455,214
Other Gases	94	2,253	1,946	1,933
Nuclear	104	107,938	101,885	104,182
Hydroelectric Conventional	4,023	78,241	78,738	78,215
Wind	947	59,629	59,075	59,082
Solar Thermal and Photovoltaic	553	3,215	3,170	3,053
Wood and Wood-Derived Fuels	351	8,520	7,508	7,570
Geothermal	197	3,724	2,592	2,782
Other Biomass	1,766	5,527	4,811	4,885
Hydroelectric Pumped Storage	156	20,858	22,368	22,271
Other Energy Sources	95	2,005	1,729	1,739
Total	**19,023**	**1,167,995**	**1,063,033**	**1,104,459**

Source: Table 4.3, EIA Electric Power Annual, 2013a

Note: This table presents generation capacity. Actual net generation is presented in Table 2-3.

In 2012, electric generating sources produced net 3,890 billion kWh to meet electricity demand. Roughly 70 percent of this electricity was produced through the combustion of fossil fuels, primarily coal and natural gas, with coal accounting for the largest single share.

Table 2-2. Electricity Net Generation in 2012 (billion kWh)

	Net Generation (Billion kWh)	Fuel Source Share
Coal	1,500.6	38.57%
Petroleum	20.1	0.52%
Natural Gas	1,132.8	29.12%
Other Gases	3.0	0.08%
Nuclear	769.3	19.78%
Hydroelectric	268.9	6.91%
Other	195.7	5.03%
Total	3,890	100%

Source: Tables 3.2.A and 3.3.A, EIA Electric Power Annual, 2013a

Note: Excludes generation from commercial and industrial sectors. Retail sales are not equal to net generation because net generation includes net exported electricity and loss of electricity that occurs through transmission and distribution.

These electric generating sources provide electricity for commercial, industrial, and residential uses, each of which consumes roughly a quarter to a third of the total electricity produced (see Table 2-3). Some of these uses are highly variable, such as heating and air conditioning in residential and commercial buildings, while others are relatively constant, such as industrial processes that operate 24 hours a day.

Table 2-3. Total U.S. Electric Power Industry Retail Sales in 2012 (billion kWh)

		Sales/Direct Use (Billion kWh)	Share of Total End Use
Retail Sales	Residential	1,375	35.87%
	Commercial	1,327	34.63%
	Industrial	986	25.72%
	Transportation	7.3	0.19%
Direct Use		138	3.59%
Total End Use		3,832	100%

Source: Table 2.2, EIA Electric Power Annual, 2013a

Coal-fired generating units have historically supplied “base-load” electricity, the portion of electricity loads which are continually present, and typically operate throughout the day. Along with nuclear generation, these coal units meet the part of demand that is relatively constant. Although much of the coal fleet operates as base load, there can be notable differences across various facilities (see Table 2-4). For example, coal-fired units less than 100 megawatts (MW) in size compose 32 percent of the total number of coal-fired units, but only 4 percent of total coal-fired capacity. Gas-fired generation is better able to vary output and is the primary option used to meet the variable portion of the electricity load and has historically supplied “peak” and “intermediate” power, when there is increased demand for electricity (for example, when businesses operate throughout the day or when people return home from work and run appliances and heating/air-conditioning), versus late at night or very early in the morning, when demand for electricity is reduced.

The evolving economics of the power sector, in particular the increased natural gas supply and subsequent relatively low natural gas prices, have resulted in more gas being utilized as base load energy in addition to supplying electricity during peak load. Projections of changes in capacity and the impact of this rule on the future need for construction of new generation capacity sources are discussed in more detail in Chapter 3 of this RIA.

Table 2-4. Coal Steam Electricity Generating Units in 2015, by Size, Age, Capacity, and Thermal Efficiency (Heat Rate)

Unit Size Grouping (MW)			No. Units	% of All Units	Avg. Age	Avg. Net Summer Capacity (MW)	Total Net Summer Capacity (MW)	% Total Capacity	Avg. Heat Rate (Btu/kWh)
0	To	25	133	14%	46	14	1,837	1%	11,860
>25	To	49	74	8%	38	37.5	2,775	1%	12,113
50	To	99	94	10%	44	72.0	6,765	2%	11,910
100	To	149	75	8%	49	124.4	9,329	3%	10,977
150	To	249	128	14%	47	91.3	24,492	9%	10,646
250	and up		432	46%	36	536.7	231,874	84%	10,336
Totals			1,266				316,480		

Source: National Electric Energy Data System (NEEDS) v.5.13

Note: The average heat rate reported is the mean of the heat rate of the units in each size category (as opposed to a generation-weighted or capacity-weighted average heat rate.) A lower heat rate indicates a higher level of fuel efficiency. Table is limited to coal-steam units online in 2013 or earlier, and excludes those units with planned retirements.

The locations of existing fossil units in NEEDS v.5.13 are shown in Figure 2-1.

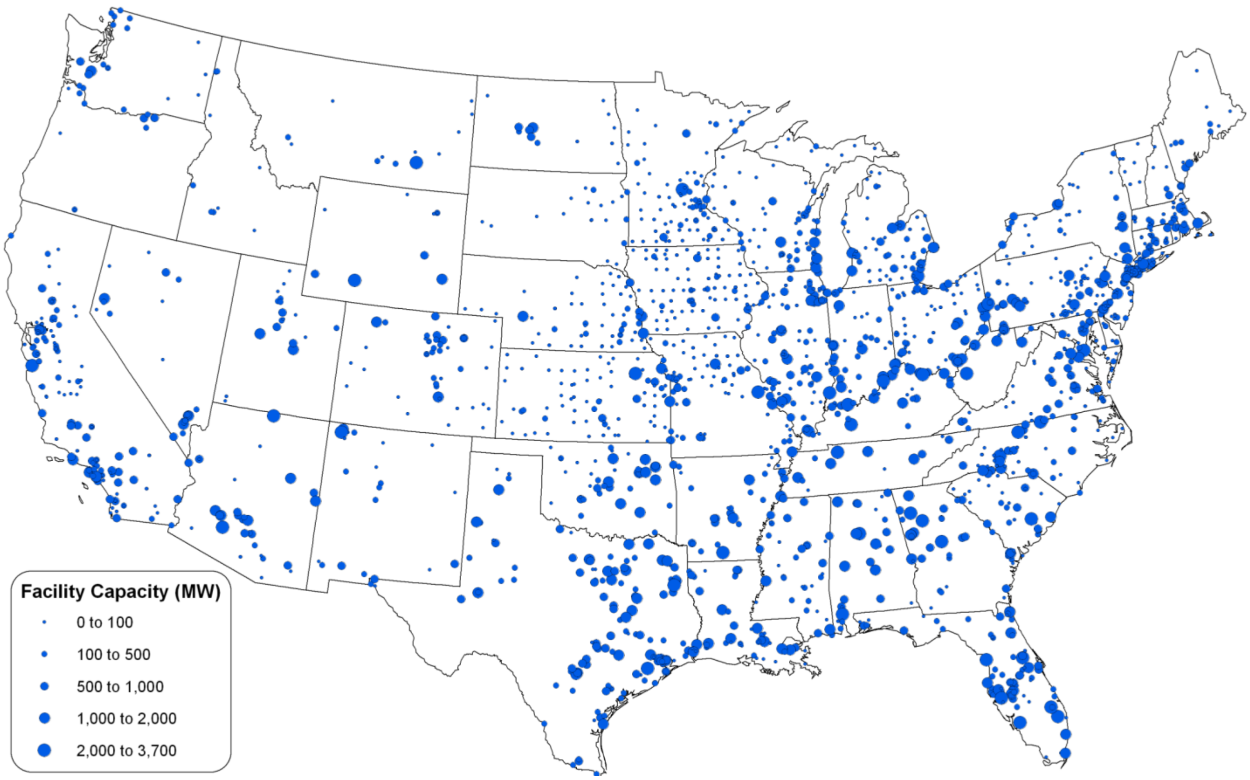

Figure 2-1. Fossil Fuel-Fired Electricity Generating Facilities, by Size

Source: National Electric Energy Data System (NEEDS) v.5.13

Note: This map displays fossil capacity at facilities in the NEEDS v.5.13 IPM frame. NEEDS reflects available fossil capacity on-line by the end of 2015. This includes planned new builds and planned retirements. In areas with a dense concentration of facilities, some facilities may be obscured.

2.2.2 Transmission

Transmission is the term used to describe the movement of electricity over a network of high voltage lines, from electric generators to substations where power is stepped down for local distribution. In the U.S. and Canada, there are three separate interconnected networks of high voltage transmission lines,[12] each operating synchronously. Within each of these transmission

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[12] These three network interconnections are the western US and Canada, corresponding approximately to the area west of the Rocky Mountains; eastern US and Canada, not including most of Texas; and a third network operating in most of Texas. These are commonly referred to as the Western Interconnect Region, Eastern Interconnect Region, and ERCOT, respectively.

networks, there are multiple areas where the operation of power plants is monitored and controlled to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator; in others, individual utilities coordinate the operations of their generation, transmission, and distribution systems to balance their common generation and load needs.

2.2.3 Distribution

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

Transmission has generally been developed by the larger vertically integrated utilities that typically operate generation and distribution networks. Often distribution is handled by a large number of utilities that purchase and sell electricity, but do not generate it. Over the last couple of decades, several jurisdictions in the United States began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. As discussed below, electricity restructuring has focused primarily on efforts to reorganize the industry to encourage competition in the generation segment of the industry, including ensuring open access of generation to the transmission and distribution services needed to deliver power to consumers. In many states, such efforts have also included separating generation assets from transmission and distribution assets to form distinct economic entities. Transmission and distribution remain price-regulated throughout the country based on the cost of service.

2.3 Deregulation and Restructuring

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

Beginning in the 1970s, government policy shifted against traditional regulatory approaches and in favor of deregulation for many important industries, including transportation (notably commercial airlines), communications, and energy, which were all thought to be natural monopolies (prior to 1970) that warranted governmental control of pricing. However, deregulation efforts in the power sector were most active during the 1990s. Some of the primary drivers for deregulation of electric power included the desire for more efficient investment choices, the economic incentive to provide least-cost electric rates through market competition, reduced costs of combustion turbine technology that opened the door for more companies to sell power with smaller investments, and complexity of monitoring utilities' cost of service and establishing cost-based rates for various customer classes.

The pace of restructuring in the electric power industry slowed significantly in response to market volatility in California and financial turmoil associated with bankruptcy filings of key energy companies. By the end of 2001, restructuring had either been delayed or suspended in eight states that previously enacted legislation or issued regulatory orders for its implementation (shown as "Suspended" in Figure 2-2 below). Eighteen other states that had seriously explored the possibility of deregulation in 2000 reported no legislative or regulatory activity in 2001 (EIA, 2003) ("Not Active" in Figure 2-2 below). Currently, there are 15 states where price deregulation of generation (restructuring) has occurred ("Active" in Figure 2-2 below). Power sector restructuring is more or less at a standstill; there have been no recent proposals to the Federal Energy Regulatory Commission (FERC) for actions aimed at wider restructuring, and no additional states have recently begun retail deregulation activity.

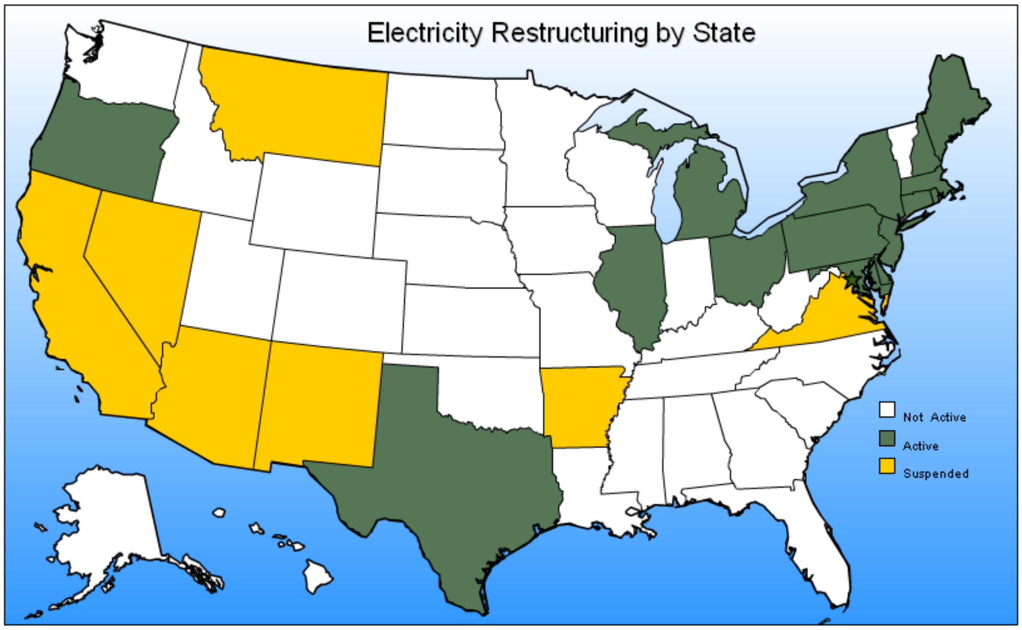

Figure 2-2. Status of State Electricity Industry Restructuring Activities

Source: EIA "Status of Electricity Restructuring by State" 2010a.

2.4 Emissions of Greenhouse Gases from Electric Utilities

The burning of fossil fuels, which generates about 70 percent of our electricity nationwide, results in emissions of greenhouse gases. The power sector is a major contributor of CO_2 in particular, but also contributes to emissions of sulfur hexafluoride (SF_6), CH_4, and N_2O. In 2012, the power sector accounted for 32 percent of total nationwide greenhouse gas emissions, measured in CO_2 equivalent,[13] a slight increase from its 30 percent share in 1990. Table 2-5 and Figure 2-3 show the contributions of the power sector relative to other major economic sectors. Table 2-6 and Figure 2-4 show the contributions of CO_2 and other GHGs from the power sector.

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[13] All CO_2 equivalent tons in this report are based on the 100-year time horizon Global Warming Potential.

Table 2-5. Domestic Emissions of Greenhouse Gases, by Economic Sector (million metric tons of CO_2 equivalent)

Sector/Source	1990	2005	2008	2009	2010	2011	2012
Electricity Generation	1,866	2,446	2,402	2,187	2,303	2,201	2,064
Transportation	1,553	2,017	1,935	1,862	1,876	1,852	1,837
Industry	1,531	1,408	1,372	1,221	1,301	1,298	1,278
Agriculture	518	584	615	605	601	613	614
Commercial	385	370	379	382	377	378	353
Residential	345	371	365	358	3607	354	321
U.S. Territories	34	58	50	48	58	58	58
Total Emissions	6,233	7,254	7,118	6,663	6,875	6,753	6,523

Note that 2005 CO_2 emissions from the electricity generation sector differ slightly from the 2005 CO_2 emissions presented in Chapter 3 due to differences in methodology (e.g., distribution of cogeneration emissions in the commercial and industrial sectors). We believe that the methodology used in Chapter 3 better corresponds to the units covered by the proposal.

Source: EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks*: 1990–2012*. April 2014.

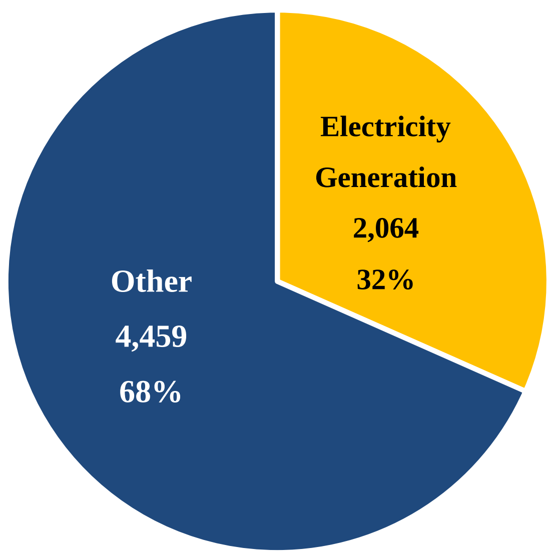


Figure 2-3. Domestic Emissions of Greenhouse Gases, 2012 (million metric tons of CO_2 equivalent)

Source: EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks*: 1990–2012*. April 2014.

Table 2-6. Greenhouse Gas Emissions from the Electricity Sector (Generation, Transmission and Distribution), 2012 (million metric tons of CO_2 equivalent)

Source	Total Emissions
CO_2 from Electricity Generation	2,023
Coal	1,511
Natural Gas	492
Fuel Oil	19
Geothermal	0.4
CH_4 from Electricity Generation	0.5
Coal	0.1
Fuel Oil	0.1
Natural Gas	0.4
Wood	+
N_2O from Electricity Generation	18.3
Coal	9.1
Fuel Oil	0.3
Natural Gas	8.7
Wood	0.1
SF_6 from Electricity Transmission and Distribution	6.0
Total	2,048

Source: EPA Inventory of U.S. Greenhouse Gas Emissions and Sink*s: 1990–2012*. April 2014.

+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

The amount of CO_2 emitted during the combustion of fossil fuels varies according to the carbon content and heating value of the fuel used (EIA, 2000) (see Table 2-7). Coal has higher carbon content than oil or natural gas and, thus, releases more CO_2 during combustion. Coal emits around 1.7 times as much carbon per unit of energy when burned as does natural gas (EPA 2013).

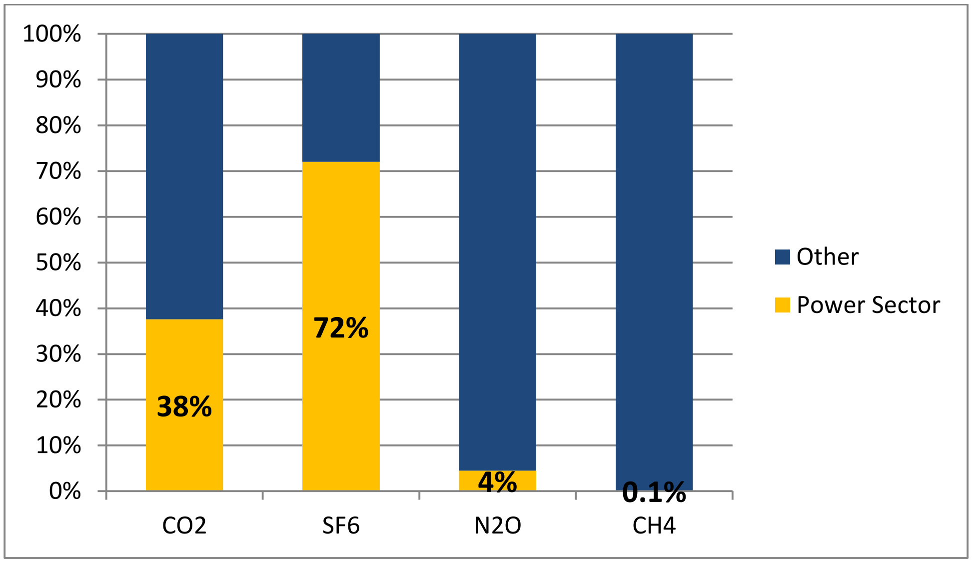


Figure 2-4. Direct GHG Emissions from the Power Sector Relative to Total Domestic GHG Emissions (2012)

Source: EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks*: 1990–2012*. April 2014.

Table 2-7. Fossil Fuel Emission Factors in EPA Modeling Applications

Fuel Type	Carbon Dioxide (lbs/MMBtu)
Coal	
Bituminous	205.2 – 206.6
Subbituminous	212.7 – 213.1
Lignite	213.5 – 217.0
Natural Gas	117.1
Fuel Oil	
Distillate	161.4
Residual	161.4 – 173.9
Biomass*	195
Waste Fuels	
Waste Coal	205.7
Petroleum Coke	225.1
Fossil Waste	321.1
Non-Fossil Waste	0
Tires	189.5
Municipal Solid Waste	91.9

Source: Documentation for IPM Base Case v.513. See also Table 9.9 of IPM Documentation.

Note: CO_2 emissions presented here for biomass reflect combustion only. They do not include any other biogenic or fossil emissions/sequestration related to biomass growth, harvest, transportation or any other biomass or processing emissions as part of the carbon cycle.

2.5 Improving GHG Performance at Existing EGUs

In proposing state goals, the analysis anticipates that states will pursue a mix of carbon-reducing strategies appropriate to each state's unique situation, developing an effective state plan that reflects the composition of the state's economy, existing state programs and measures, and characteristics of the state's existing electricity power system (e.g., utility regulatory structure, generation mix, transmission system and electricity demand). The analysis assumes states will develop plans involving four categories ("building blocks") of demonstrated approaches to improve the GHG performance of existing EGUs in the power sector:

1. Reducing the carbon intensity of generation at individual affected EGUs through heat-rate improvements.
2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including natural gas combined cycle [NGCC] units that are under construction).
3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.
4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

This section briefly describes each of these four building block categories. Our analyses of the magnitude of the opportunity for improvements from each category, and more detail about how we used each state's unique situation and availability of demonstrated approaches to improve GHG performance to determine state-specific emission goals, can be found in Chapter 5 of the Greenhouse Gas Abatement Measures TSD.

The first building block encompasses various improvements at existing EGUs that can lower the amount of CO_2 they emit when generating power. Heat rate improvements result in any changes in equipment, operating procedures or maintenance practices that increase the efficiency of converting fuel energy into electricity by an EGU. Such efficiency changes result in more electricity being generated by each unit of fuel (e.g., ton of coal or cubic foot of gas), thereby lowering the amount of CO_2 per kWh of electricity produced as a byproduct of fuel combustion.

The second building block consists of improvements to lower the electric system's overall carbon intensity by shifting generation among existing EGUs. The nation's EGUs are connected by transmission grids extending over large regions. Through these interconnections, EGU owners and/or grid operators prioritize among EGUs when deciding which ones to operate (i.e., "dispatch") to meet electricity demand at any time, subject to various constraints. Opportunities exist to lower significantly the electric system's carbon intensity through redispatch among existing EGUs, particularly by shifting generation from coal units to natural gas combined cycle (NGCC) units.[14] Over the last several years, advances in the production of natural gas have helped reduce natural gas prices and improved the competitive position of gas-fired units relative to coal-fired units. Operators have already shifted significant quantities of generation from coal units to NGCCs, absent any federal CO_2 requirements. Additional redispatch opportunities exist to further reduce carbon intensity of the power system, with extent of the additional opportunities varying region, based on factors such as the mix of EGU types, the relative prices of coal and natural gas and the amount of available NGCC capacity.

The third building block consists of the potential to increase the amount of lower carbon intensity generation by expanding low-carbon and renewable generating capacity. Adding new nuclear or renewable generating capacity to the electric system would tend to shift generation to the new units from existing EGUs with higher carbon intensity. Such expansion is consistent with current trends. While not included in the goal setting for building block 3, the addition of new NGCC capacity would have a similar impact and is one option states may choose to achieve the goal.

The fourth building block consists of improving the GHG performance of the power sector by reducing the total amount of generation required – in other words, improving demand-

[14]We view opportunities to shift generation to existing renewable EGUs such as wind or solar units as limited because such units already tend to run when capable of doing so due to their low variable operating costs.

side efficiency. Many studies have found that significant improvements in demand-side efficiency can be realized at less cost than the savings from avoided power generation.[15] These electricity demand reductions can be achieved through policies or programs, such as subsidies for the purchase of energy-efficient appliances, which incentivize investment in cost-effective efficiency improvements by overcoming market imperfections that otherwise thwart these investments. States already employ a variety of mechanisms for this purpose. These include energy efficiency resource standards, building energy codes and appliance and equipment energy standards. Reducing electricity demand also enhances efficiency by reducing the absolute amount of transmission and distribution losses that occur across the grid between the electricity generation sites and the demand sites. Particularly when integrated into a comprehensive approach for addressing GHG emissions, demand-side efficiency improvements can improve the carbon profile of the electricity supply system.

2.6 GHG and Clean Energy Regulation in the Power Sector

2.6.1 State Policies

Several states recently established emission performance standards or other measures to limit emissions of GHGs from existing EGUs that are comparable to this proposal for existing source guidance.

In 2003, then-Governor George Pataki of New York sent a letter to his counterparts in the Northeast and Mid-Atlantic inviting them to participate in the development of a regional cap-and-trade program addressing power plant CO_2 emissions. This program, known as the Regional Greenhouse Gas Initiative (RGGI), began in 2009 and sets a regional CO_2 cap for participating states. The currently participating states include: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. The cap covers CO_2 emissions from all fossil-fired EGUs greater than 25 MW in participating states, and limits total emissions to 91 million short tons in 2014. This emissions budget is reduced 2.5% annually

[15] *See, e.g.*, Granade, et al., July 2009 and EPRI, 2009.

from 2015 to 2020.

In September 2006, then-Governor of California Arnold Schwarzenegger signed into law Senate Bill 1368. The law limits long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the California Energy Commission and the California Public Utilities Commission. The Energy Commission has designed regulations that establish a standard for new and existing baseload generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lb CO_2/MWh.

In 2006 Governor Schwarzenegger also signed into law Assembly Bill 32, the Global Warming Solutions Act of 2006. This act includes a multi-sector GHG cap-and-trade program which covers approximately 85% of the state GHG emissions. EGUs are included in phase I of the program, which began in 2013. Phase II begins in 2015 and includes upstream sources. The cap is based on a 2 percent reduction from total 2012 expected emissions, and declines 2 percent annually through 2014, then 3 percent each year until 2020.

In May 2007, then-Governor Christine Gregoire of Washington signed Substitute Senate Bill 6001, which established statewide GHG emissions reduction goals, and imposed an emission standard that applies to any baseload electric generation that commenced operation after June 1, 2008 and is located in Washington, whether or not that generation serves load located within the state. Baseload generation facilities must initially comply with an emission limit of 1,100 lb CO_2/MWh. Bill 6001 also prohibited Washington electric utilities from entering new long-term power contracts after June 30, 2008 with any power plant exceeding the 1,100 lb CO_2/MWh limit.

In July 2009, then-Governor Theodore Kulongoski of Oregon signed Senate Bill 101, which mandated that facilities generating baseload electricity, whether gas- or coal-fired, must have emissions equal to or less than 1,100 lb CO_2/MWh, and prohibited utilities from entering into long-term purchase agreements for baseload electricity with out-of-state facilities that do not meet that standard. Natural gas- and petroleum distillate-fired facilities that are primarily used to serve peak demand or to integrate energy from renewable resources are specifically exempted from the performance standard.

In August 2011, New York Governor Andrew Cuomo signed the Power NY Act of 2011. This regulation establishes CO_2 emission standards for new and modified electric generators greater than 25 MW. The standards vary based on the type of facility: baseload facilities must meet a CO_2 standard of 925 lb/MWh or 120 lb/MMBtu, and peaking facilities must meet a CO_2 standard of 1,450 lbs/MWh or 160 lbs/MMBtu.

Additionally, the majority of states have implemented Renewable Portfolio Standards (RPS), or Renewable Electricity Standards (RES). These programs are designed to increase the renewable share of a state's total electricity generation. Currently 29 states and the District of Columbia have enforceable RPS or other mandatory renewable capacity policies, and 9 states have voluntary goals.[16] These programs vary widely in structure, enforcement, and scope. For more information about existing state policies and programs that reduce power sector CO_2 emissions, see the State Plan Considerations Technical Support Document Appendix.

2.6.2 Federal Policies

In April 2007, the Supreme Court concluded that GHGs met the CAA definition of an air pollutant, giving the EPA the authority to regulate GHGs under the CAA contingent upon an agency determination that GHG emissions from new motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. This decision set in motion EPA's finding that GHG endangered public health, welfare and its regulation of GHG emissions for motor vehicles and set the stage for the determination of whether other sources of GHG emissions, including stationary sources, would need to be regulated as well.

In response to the FY2008 Consolidated Appropriations Act (H.R. 2764; Public Law 110–161), the EPA issued the Mandatory Reporting of Greenhouse Gases Rule (74 FR 5620) which required reporting of GHG data and other relevant information from fossil fuel suppliers and industrial gas suppliers, direct greenhouse gas emitters, and manufacturers of heavy-duty and

[16] Database of State Incentives for Renewables and Efficiency, March 2013 and Alaska House Bill 306, 2010.

off-road vehicles and engines. The purpose of the rule was to collect accurate and timely GHG data to inform future policy decisions. As such, it did not require that sources control greenhouse gases, but sources above certain threshold levels must monitor and report emissions.

In August 2007, the EPA issued a prevention of significant deterioration (PSD) permit to Deseret Power Electric Cooperative, authorizing it to construct a new waste-coal-fired EGU near its existing Bonanza Power Plant, in Bonanza, Utah. The permit did not include emissions control requirements for CO_2. The EPA acknowledged the Supreme Court decision, but found that decision alone did not require PSD permits to include limits on CO_2 emissions. Sierra Club challenged the Deseret permit. In November 2008, the Environmental Appeals Board (EAB) remanded the permit to the EPA to reconsider "whether or not to impose a CO_2 BACT (best available control technology) limit in light of the 'subject to regulation' definition under the CAA." The remand was based in part on EAB's finding that there was not an established EPA interpretation of the regulatory phrase "subject to regulation."

In December 2008, the Administrator issued a memo indicating that the PSD Permitting Program would apply to pollutants that are subject to either a provision in the CAA or a regulation adopted by the EPA under the CAA that requires actual control of emissions of that pollutant. The memo further explained that pollutants for which the EPA regulations only require monitoring or reporting, such as the provisions for CO_2 in the Acid Rain Program, are not subject to PSD permitting. Fifteen organizations petitioned the EPA for reconsideration, prompting the agency to issue a revised finding in March 2009. After reviewing comments, the EPA affirmed the position that PSD permitting is not triggered for a pollutant such as GHGs until a final nationwide rule requires actual control of emissions of the pollutant. For GHGs, this meant January 2011 when the first national rule limiting GHG emissions for cars and light trucks was scheduled to take effect. Therefore, a permit issued after January 2, 2011, would have to address GHG emissions.

The Administrator signed two distinct findings in December 2009 regarding greenhouse gases under section 202(a) of the Clean Air Act. The endangerment finding indicated that current and projected concentrations of the six key well-mixed greenhouse gases — CO_2, CH_4, N_2O, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and SF_6 — in the atmosphere threaten the public health and welfare of current and future generations. These greenhouse gases have long lifetimes and, as a result, become homogeneously distributed through the lower level of the Earth's atmosphere (IPCC, 2001). This differentiates them from other greenhouse gases that are not homogeneously distributed in the atmosphere. The cause and contribute finding indicated that the combined emissions of these well-mixed greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the greenhouse gas pollution which threatens public health and welfare. Both findings were published in the Federal Register on December 15, 2009 (Docket ID EPA-HQ-OAR-2009-0171). These findings did not themselves impose any requirements on any industry or other entities, but allowed the EPA to regulate greenhouse gases under the CAA (see preamble section II.D for regulatory background). This action was a prerequisite to implementing the EPA's proposed greenhouse gas emission standards for light-duty vehicles, which was finalized in January 2010. Once a pollutant is regulated under the CAA, it is subject to permitting requirements under the PSD and Title V programs. The 2009 Endangerment Finding and a denial of reconsideration were challenged in a lawsuit; on June 26, 2012, the DC Circuit Court upheld the Endangerment Finding and the Reconsideration Denial, ruling that the Finding was neither arbitrary nor capricious, was consistent with Massachusetts v. EPA, and was adequately supported by the administrative record. The Court found that the EPA had based its decision on "substantial scientific evidence," noted that the EPA's reliance on assessments was consistent with the methods decision-makers often use to make a science-based judgment, and stated that "EPA's interpretation of the governing CAA provisions is unambiguously correct."

In May 2010, the EPA issued the final Tailoring Rule which set thresholds for GHG emissions that define when permits under the New Source Review and Title V Operating Permit programs are required for new and existing industrial facilities. Facilities responsible for nearly 70 percent of the national GHG emissions from stationary sources, including EGUs, were subject to permitting requirements under the rule. This rule was upheld by the D.C. Circuit in 2012.

On January 8, 2014 EPA proposed a new source performance standard (NSPS) for emissions of carbon dioxide for new fossil fuel-fired electric utility generating units. This action proposes to establish separate standards for fossil fuel-fired electric steam generating units (utility boilers and Integrated Gasification Combined Cycle (IGCC) units) and for natural gas-fired stationary combustion turbines. These proposed standards reflect separate determinations of the best system of emission reduction (BSER) adequately demonstrated for utility boilers and IGCC units and for natural gas-fired stationary combustion turbines. This action proposes a standard of performance for utility boilers and IGCC units based on partial implementation of carbon capture and storage (CCS) as the BSER. The proposed emission limit for those sources is 1,100 lb CO_2/MWh. This action also proposes standards of performance for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle (NGCC) technology as the BSER. The proposed emission limits for those sources are 1,000 lb CO2/MWh for larger units and 1,100 lb CO_2/MWh for smaller units.

2.7 Revenues, Expenses, and Prices

Due to lower retail electricity sales, total utility operating revenues declined in 2012 to $271 billion from a peak of almost $300 billion in 2008. Despite revenues not returning to 2008, operating expenses were appreciably lower and as a result, net income in 2012 rose in comparison previous years (see Table 2-8). Recent economic events and continued energy efficiency improvements have put downward pressure on electricity demand, thus dampening electricity prices and consumption (utility revenues), but have also reduced the price and cost of fossil fuels and other expenses. Electricity sales and revenues associated with the generation, transmission, and distribution of electricity are expected to rebound and increase modestly by 2015, when revenues are projected to be roughly $359 billion (see Table 2-9).

Table 2-8 shows that investor-owned utilities (IOUs) earned income of about 13 percent compared to total revenues in 2012. Based on EIA's *Annual Energy Outlook 2013,* Table 2-9 shows that the power sector is projected to derive revenues of $359 billion in 2015. Assuming the same income ratio from IOUs (with no income kept by public power), and using the same proportion of power sales from public power as observed in 2012, the EPA projects that the power sector will expend over $372 billion in 2015 to generate, transmit, and distribute electricity to end-use consumers.

Over the past 50 years, real national average retail electricity prices have ranged from around 8 cents per kWh in the early 1970s, to around 12 cents, reached in the early 1980s. Generally, retail electricity prices do not change rapidly and do not display the variability of other energy or commodity prices, although the frequency at which these prices change varies across different types of customers. Retail rate regulation has largely insulated consumers from the rising and falling wholesale electricity price signals whose variation in the marketplace on an hourly, daily, and seasonal basis is critical for driving lowest-cost matching of supply and demand. In fact, the real price of electricity today is lower than it was in the early 1960s and 1980s (see Figure 2-5).

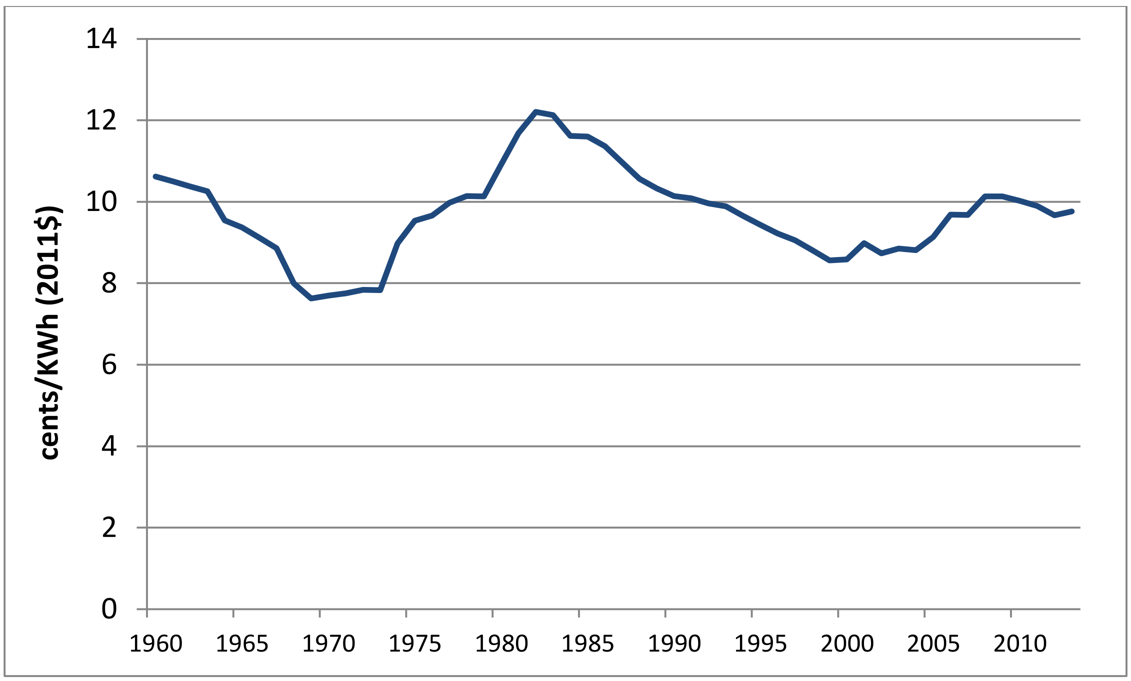


Figure 2-5. National Average Retail Electricity Price (1960 – 2013, 2011$)

Source: EIA **Monthly Energy Review** 2013, BEA **National Income Product Accoun**ts 2014

Table 2-8. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities ($millions)

	2010	2011	2012
Utility Operating Revenues	**285,512**	**280,520**	**270,912**
Electric Utility	260,119	255,573	249,166
Other Utility	25,393	24,946	21,745
Utility Operating Expenses	**253,022**	**247,118**	**235,694**
Electric Utility	234,173	228,873	220,722
Operation	166,922	161,460	152,379
Production	128,831	122,520	111,714
Cost of Fuel	44,138	42,779	38,998
Purchased Power	67,284	61,447	54,570
Other	17,409	18,294	18,146
Transmission	6,948	6,876	7,183
Distribution	4,007	4,044	4,181
Customer Accounts	5,091	5,180	5,086
Customer Service	4,741	5,311	5,640
Sales	185	185	221
Admin. and General	17,120	17,343	18,353
Maintenance	14,957	15,772	15,489
Depreciation	20,951	22,555	23,677
Taxes and Other	31,343	29,086	29,177
Other Utility	18,849	18,245	14,972
Net Utility Operating Income	**32,490**	**33,402**	**35,218**

Source: Table 8.3, *EIA Electric Power Annual*, 2013a. Values are in millions of current year (i.e., nominal) terms.

Note: This data does not include information for public utilities.

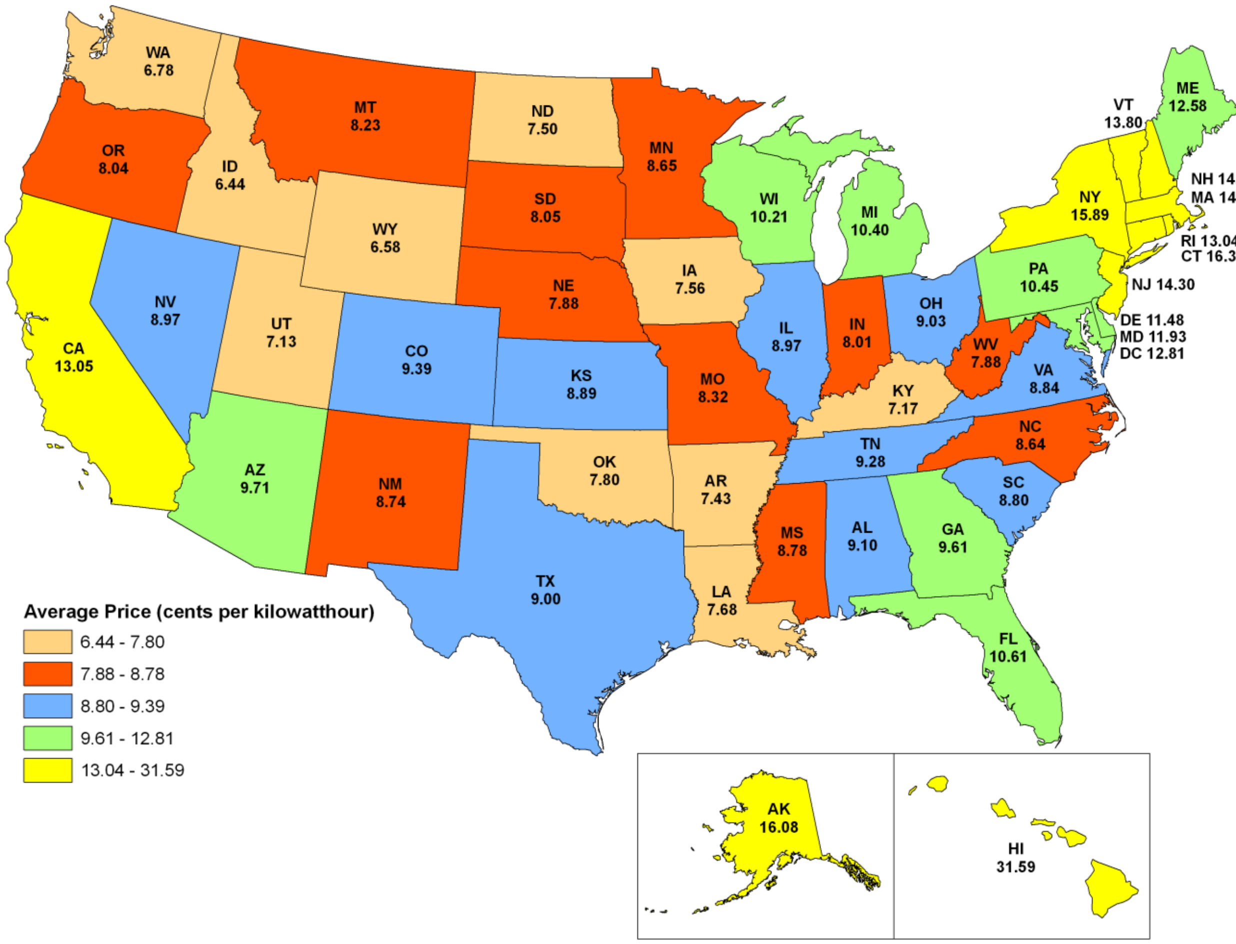
Table 2-9. Projected Revenues by Service Category in 2015 for Public Power and Investor-Owned Utilities (billions)

Generation	$207
Transmission	$40
Distribution	$111
Total	**$359**

Source: EIA 2013b

Note: Data are derived by taking either total electricity use (for generation) or sales (transmission and distribution) and multiplying by forecasted prices by service category from Table 8 of EIA AEO 2013 (Electricity Supply, Disposition, Prices, and Emissions).

On a state-by-state basis, retail electricity prices vary considerably. The Northeast and California have average retail prices that can be as much as double those of other states (see Figure 2-6).



Note: Data are displayed as 5 groups of 10 States and the District of Columbia. U.S. total average price per kilowatt-hour is 9.90 cents.

Source: U.S. Energy Information Administration. 2011b.

Figure 2-6. Average Retail Electricity Price by State (cents/kWh), 2011

2.8 Natural Gas Market

The natural gas market in the United States has historically experienced significant price volatility from year to year, between seasons within a year, and can undergo major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). Over the last decade, gas prices (both Henry Hub prices and delivered prices to the power sector) have ranged from below $3 to nearly $10/mmBtu on an annual average basis (see Figure 2-7). During that time, the daily price of natural gas reached as high as $15/mmBtu.

Recent forecasts of natural gas availability have also experienced considerable revision as new sources of gas have been discovered and have come to market, although there continues to be some uncertainty surrounding the precise quantity of the resource base.

Current and projected natural gas prices are considerably lower than the prices observed over the past decade, largely due to advances in hydraulic fracturing and horizontal drilling techniques that have opened up new shale gas resources and substantially increased the supply of economically recoverable natural gas. According to an EIA “Energy in Brief” (EIA 2012b):

“Shale gas refers to natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas. Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously uneconomical to produce. The production of natural gas from shale formations has rejuvenated the natural gas industry in the United States.”

The U.S. Energy Information Administration's Annual Energy Outlook 2012 (Early Release) estimates that the United States possessed 2,214 trillion cubic feet (Tcf) of technically recoverable natural gas resources as of January 1, 2010. Natural gas from proven and unproven shale resources accounts for 542 Tcf of this resource estimate. The AEO 2012 (Early Release) notes that many shale formations, especially the Marcellus, are so large that only small portions of the entire formations have been intensively production-tested. Consequently, the estimate of technically recoverable resources is highly uncertain, and is regularly updated as more information is gained through drilling and production. At the 2010 rate of U.S. consumption (about 24.1 Tcf per year), 2,214 Tcf of natural gas is enough to supply over 90 years of use. Although the estimate of the shale gas resource base is lower than in the prior edition of the Outlook, shale gas production estimates increased between the 2011 and 2012 Outlooks, driven by lower drilling costs and continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value in energy equivalent terms than dry natural gas.[17]

EIA's projections of natural gas conditions did not change substantially in AEO 2014 from the AEO 2013, and EIA is still forecasting abundant reserves consistent with the above findings. Recent historical data reported to EIA is also consistent with these trends, with 2013 being the highest year on record for domestic natural gas production.[18] The average delivered natural gas price to the power sector was $4.49 per MMBtu in 2013, higher than in 2012 ($3.54/MMBtu), but still down from $4.89/MMBtu in 2011.[19]

EIA projections of future natural gas prices assume trends that are consistent with historical and current market behavior, technological and demographic changes, and current laws and regulations.[20] Depending on actual conditions, there may be significant variation from the price projected in the reference case and the price observed. To address this uncertainty, EIA issues a range of alternative cases, including cases with higher and lower economic growth, which address many of the uncertainties inherent in the long-term projections.

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[17] For more information, see: http://www.eia.gov/forecasts/archive/aeo11/IF_all.cfm#prospectshale; http://www.eia.gov/energy_in_brief/about_shale_gas.cfm

[18] http://www.eia.gov/dnav/ng/hist/n9010us2a.htm

[19] http://www.eia.gov/dnav/ng/hist/n3045us3A.htm; Assumes that 1 TCF = 1.023 MMBtu natural gas (http://www.eia.gov/tools/faqs/faq.cfm?id=45&t=8)

[20] EIA 2010b.

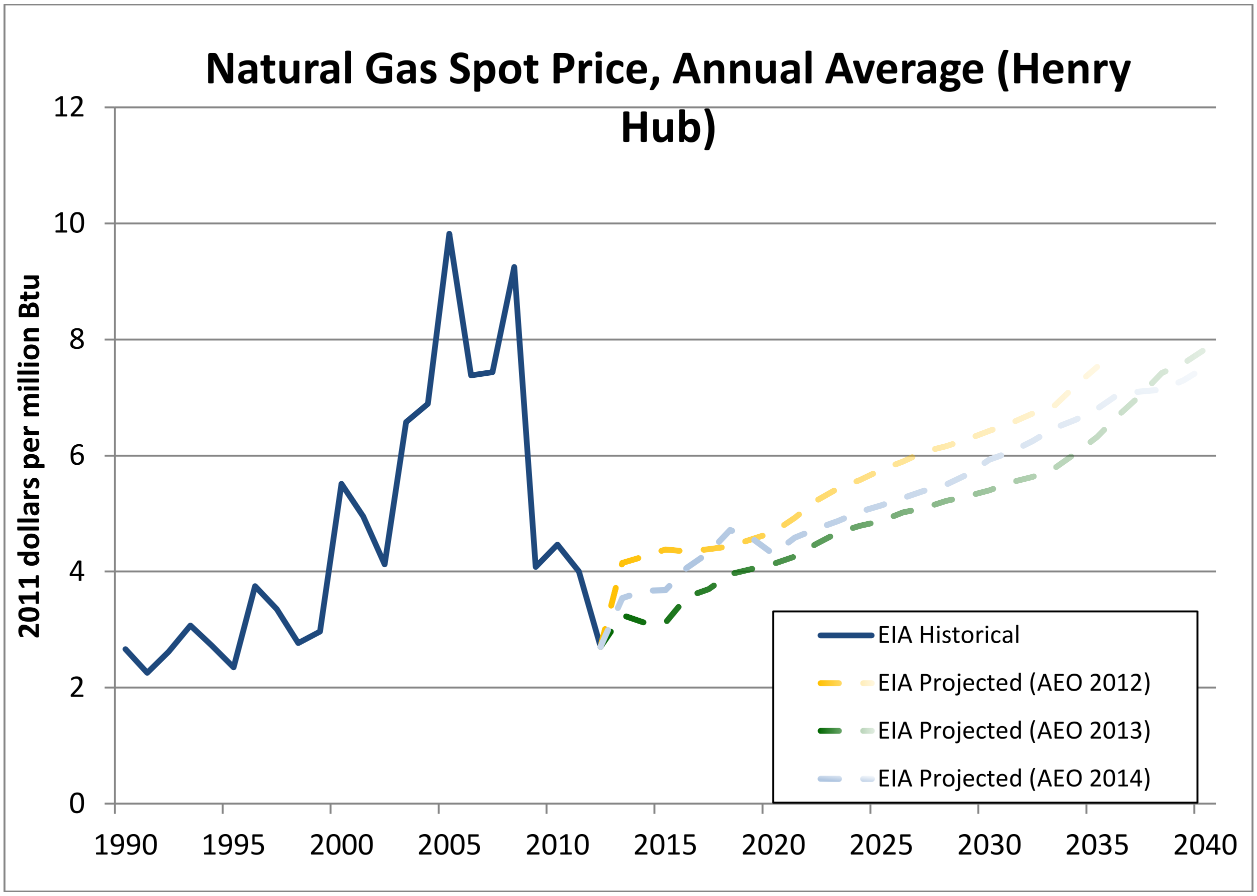

Figure 2-7. Natural Gas Spot Price, Annual Average (Henry Hub)

Source: EIA 2010c, EIA 2012a, EIA 2013b, EIA 2014

2.9 Electricity Demand and Demand Response

Electricity performs a vital and high-value function in the economy. Historically, growth in electricity consumption has been closely aligned with economic growth. Overall, the U.S. economy has become more efficient over time, producing more output (gross domestic product – GDP) per unit of energy input, with per capita energy use fairly constant over the past 30 years (EIA, 2010d). The growth rate of electricity demanded has also been in overall decline for the past sixty years (see Figure 2-8), with several key drivers that are worth noting. First, there has been a significant structural shift in the U.S. economy towards less energy-intensive sectors, like services.[21] Second, companies face increasing financial incentives to reduce expenditures, including those for energy. Third, companies are responding to the marketplace and continually develop and bring to market new technologies that reduce energy consumption. Fourth, energy efficiency policies at the state and Federal level have reduced demand. These broader changes have altered the outlook for future electricity growth.

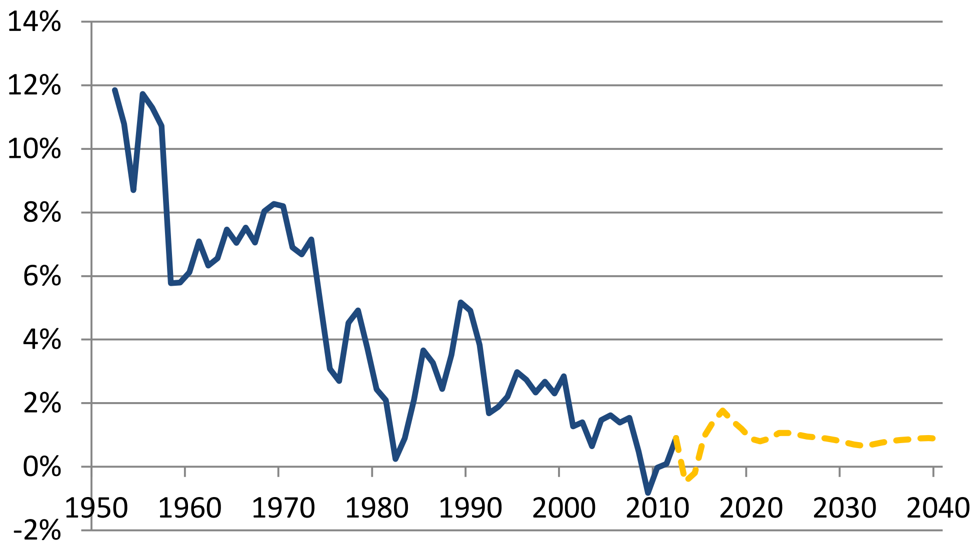

Figure 2-8. Electricity Growth Rate (3-Year Rolling Average) and Projections from the Annual Energy Outlook 2014

Source: EIA 2009, EIA 2014

State policies have driven a rapid increase in investment in utility energy efficiency programs (increasing from $1.6 billion in 2006 to $5.9 billion in 2011)[22] and investments in energy efficiency are projected to continue to increase significantly (to $8 billion or more) for at least the next decade[23], driven largely by the growing number of states that have adopted energy

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[21] EIA 2013b

[22] American Council for an Energy-Efficient Economy (ACEEE). November 2013. The 2013 State Energy Efficiency Scorecard. Available at http://www.aceee.org/state-policy/scorecard.

[23] Barbose, G.L., C.A. Goldman, I. Ml. Hoffman, M. A. Billingsley. January 2013. The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025. LBNL-5803E.

efficiency resource standards. These investments, and other energy efficiency policies at both the state and federal level, create incentives to reduce electricity consumption and peak load. According to data reported to EIA, energy efficiency programs reduced annual electricity demand by 3.74% in 2012.[24]

Demand for electricity, especially in the short run, is not very sensitive to changes in prices and is considered relatively price inelastic, although some demand reduction does occur in response to price. With that in mind, the EPA modeling does not typically incorporate a "demand response" in its electric generation modeling (see the discussion in Chapter 3) to the increases in electricity prices typically projected for EPA rulemakings.

Available at http://emp.lbl.gov/publications/future-utility-customer-funded energy-efficiency-programs-united-states-projected-spend.

[24] U.S. Energy Information Administration Form EIA-861 data files. 2012. Available at http://www.eia.gov/electricity/data/eia861/.

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CHAPTER 3: COST, ECONOMIC, AND ENERGY IMPACTS

3.1 Introduction

This chapter reports the compliance cost, economic, and energy impact analysis performed for the proposed rule. EPA used the Integrated Planning Model (IPM), developed by ICF International, to conduct its analysis. IPM is a dynamic linear programming model that can be used to examine air pollution control policies for CO_2, SO_2, NO_X, Hg, HCl, and other air pollutants throughout the United States for the entire power system. The IPM analysis is complemented by an analysis of the cost and scope of reductions in electricity demand that can be achieved through energy efficiency programs.

3.2 Overview

EPA is proposing emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for CO_2 emissions from the power sector, as well as guidelines for states to use in developing plans to attain the state-specific goals. This rule, as proposed, would set in motion actions to lower the carbon intensity of power generation in the United States.

Over the last decade, EPA has conducted extensive analyses of regulatory actions affecting the power sector. These efforts support the Agency's understanding of key variables that influence the effects of a policy and provide the framework for how the Agency estimates the costs and benefits associated with its actions.

The estimated annual costs of the proposed action are between $5.4 and $7.4 billion in 2020 and between $7.3 and $8.8 billion in 2030 for the primary Option (Option 1). The alternative option (Option 2) has annual estimated costs of between $4.2 and $5.4 billion in 2020 and between $4.5 and $5.5 billion in 2025[25, 26]

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[25] These costs do not include monitoring, reporting, and recordkeeping costs. For more information, see section 3.11.

[26] All costs represent real dollars ($2011).

3.3 Power Sector Modelling Framework

The Integrated Planning Model (IPM), developed by ICF Consulting, is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system. EPA used IPM, inclusive of the electricity demand reductions achieved through the energy efficiency scenario included in the proposed rule, to project likely future electricity market conditions with and without the proposed rule. The level of energy efficiency-driven reductions in electricity demand and their associated costs are reported in section 3.6.

IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. EPA has used IPM for over two decades to better understand power sector behavior under future business-as-usual conditions and evaluate the economic and emission impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[27]

Although the Agency typically focuses on broad system effects when assessing the economic impacts of a particular policy, EPA's application of IPM includes a detailed and sophisticated regional representation of key variables affecting power sector behavior.

The model incorporates a detailed representation of the fossil-fuel supply system that is used to forecast equilibrium fuel prices. The model includes an endogenous representation of the

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[27] Detailed information and documentation of EPA's Base Case using IPM (v5.13), including all the underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: http://www.epa.gov/powersectormodeling

North American natural gas supply system through a natural gas module that reflects a partial supply/demand equilibrium of the North American gas market accounting for varying levels of potential power sector gas demand and corresponding gas production and price levels.[28] This module consists of 118 supply, demand, and storage nodes and 15 liquefied natural gas re-gasification facility locations that are tied together by a series of linkages (i.e., pipelines) that represent the North American natural gas transmission and distribution network.

IPM also endogenously models the partial equilibrium of coal supply and EGU coal demand levels throughout the continental U.S., taking into account assumed non-power sector demand and imports/exports. IPM reflects 36 coal supply regions, 14 coal grades, and the coal transport network, which consists of over four thousand linkages representing rail, barge, and truck and conveyer linkages. The coal supply curves in IPM, which are publicly available, were developed during a thorough bottom-up, mine-by-mine approach that depicts the coal choices and associated supply costs that power plants would face if selecting that coal over the modeling time horizon. The IPM documentation outlines the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 36 coal regions curves. The coal supply curves were developed in consultation with Wood Mackenzie, one of the leading energy consulting firms and specialists in coal supply. These curves have been independently reviewed by industry experts and have been made available for public review prior to this rulemaking process.[29]

EPA has used IPM extensively over the past two decades to analyze options for reducing power sector emissions. Previously, the model has been used to forecast the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule, Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), and the proposed Carbon Pollution Standards for New Power Plants.

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[28] See Chapter 10 of EPA's Base Case using IPM (v5.13) documentation, available at: http://www.epa.gov/powersectormodeling/BaseCasev513.html

[29] See Chapter 9 of EPA's Base Case using IPM (v5.13) documentation, available at: http://www.epa.gov/powersectormodeling/BaseCasev513.html

The model and EPA's assumptions input into the model undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly detailed review of key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts. For example, in the late 1990's, the Science Advisory Board reviewed IPM as part of the CAA Amendments Section 812 prospective studies that are periodically conducted. The model has also undergone considerable interagency scrutiny when it has been used to conduct over a dozen legislative analyses (performed at Congressional request) over the past decade. The Agency has also used the model in a number of comparative modeling exercises sponsored by Stanford University's Energy Modeling Forum over the past 15 years.

IPM has also been employed by states (e.g., for RGGI, the Western Regional Air Partnership, Ozone Transport Assessment Group), other Federal and state agencies, environmental groups, and industry, all of whom subject the model to their own review procedures.

3.3.1 Recent Updates to EPA's Base Case using IPM (v.5.13)

This new IPM modeling platform (v.5.13) incorporates important structural improvements and data updates with respect to the previous version (v.4.10_MATS), and includes notable changes to the modeling architecture. This is the fifth major iteration of EPA's base case using IPM, and calibrates certain information and data from the Energy Information Agency's (EIA) Annual Energy Outlook (AEO), in this case AEO 2013 (hence the platform name of v5.13).

The current base case represents a projection of electricity sector activity that takes into account only those Federal and state laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized in August 2013. The

EPA Base Case v.5.13 includes the Clean Air Interstate Rule (CAIR),[30] the Mercury and Air Toxics Rule (MATS), and other state and Federal regulations to the extent that they contain measures, permits, or other air-related limitations or requirements.[31]

EPA has also updated the National Electric Energy Data System (NEEDS). This database contains the unit-level data that is used to construct the "model" plants that represent existing and committed[32] units in EPA modeling applications of IPM. NEEDS includes basic geographic, operating, air emissions, and other data on these generating units.[33]

Other routine updates were also adopted in v5.13. These include changes based on public comments that have been received over the last few years, updates reflecting planned new power plant construction, retirements, new power plant cost and performance, pollution control costs and performance, emission rate assignments, and state rules and enforcement actions. The update also included further refinement to the modeled regions to reflect more recent power market

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[30] EPA Base Case v.5.13 includes the Clean Air Interstate Rule (CAIR), a Federal regulatory measure for achieving the 1997 National Ambient Air Quality Standards (NAAQS) for ozone (8-hour average of 0.08 ppm) and fine particles (24-hour average of 65 $\mu g/m^3$ or less and annual average of 15 $\mu g/m^3$ for particles of diameter 2.5 micrometers or less, i.e., $PM_{2.5}$). Originally issued on March 10, 2005, CAIR was remanded back to EPA by the U.S. Court of Appeals for the District of Columbia Circuit in December 2008 and EPA was required to correct legal flaws in the regulations that had been cited in a ruling by the Court in July 2008. CAIR remains in effect until replaced by EPA pursuant to the Court's ruling. CAIR's provisions were still in effect when EPA Base Case v.5.13 was released.

[31] On May 19, 2014, EPA finalized the "National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities". This finalized rule, which implements section 316(b) of the Clean Water Act, affects sources with a cooling water design intake flow greater than 2 million gallons a day. Many of the sources affected by the 316(b) rule are electricity generating units, but not all of these generating units are subject to the proposed 111(d) rule. The 316(b) rule is not reflected in the base case of the 111(d) proposed rule analysis. However, the EPA estimated that the 316(b) rule will have relatively minor impacts on facilities affected by that regulation, with a net decrease in electricity generating capacity of 1 GW in 2030 (less than 0.1% of total 2030 base case generating capacity), generally reflecting the retirement of older, less efficient generating units with very low capacity utilization rates. It is not expected that the analysis described in this RIA would be meaningfully affected if the expected effects of the 316(b) rule were included in the base case.

[32] v.5.13 includes planned units that had broken ground or secured financing and were expected to be online by the end of 2015; one geothermal unit and four nuclear units that are scheduled to come online after 2015 were also included. For more information, see Chapter 4 of EPA's Base Case using IPM (v5.13) documentation, available at: http://www.epa.gov/powersectormodeling/BaseCasev513.html

[33] The NEEDS database can be found on the EPA's website for the Base Case using IPM (v5.13), <http://www.epa.gov/powersectormodeling/BaseCasev513.html>.

structure based on NERC, FERC, EIA, and other data and planning sources, and now includes more regions that better reflect limitations on current power system dispatch and transmission behavior.

3.4 State Goals in this Proposal

In this action, the EPA is proposing state-specific rate-based goals to guide states in the development of their plans. The agency is proposing one option (Option 1) for state-specific goals and requesting comment on a second set of state-specific goals and compliance period (Option 2).

Table 3-1. Proposed State Goals (Adjusted MWh-Weighted-Average Pounds of CO_2 Per Net MWh from all Affected Fossil Fuel-Fired EGUs) for Options 1 and 2

State[34]	Option 1		Option 2	
	Interim Goal (2020-2029)	Final Goal (2030 Forward)	Interim Goal (2020-2024)	Final Goal (2025 Forward)
Alabama	1,147	1,059	1,270	1,237
Alaska	1,097	1,003	1,170	1,131
Arizona *	735	702	779	763
Arkansas	968	910	1,083	1,058
California	556	537	582	571
Colorado	1,159	1,108	1,265	1,227
Connecticut	597	540	651	627
Delaware	913	841	1,007	983
Florida	794	740	907	884
Georgia	891	834	997	964
Hawaii	1,378	1,306	1,446	1,417
Idaho	244	228	261	254
Illinois	1,366	1,271	1,501	1,457
Indiana	1,607	1,531	1,715	1,683
Iowa	1,341	1,301	1,436	1,417
Kansas	1,578	1,499	1,678	1,625
Kentucky	1,844	1,763	1,951	1,918
Louisiana	948	883	1,052	1,025
Maine	393	378	418	410
Maryland	1,347	1,187	1,518	1,440
Massachusetts	655	576	715	683
Michigan	1,227	1,161	1,349	1,319
Minnesota	911	873	1,018	999
Mississippi	732	692	765	743

[34] The EPA has not developed goals for Vermont and the District of Columbia because current information indicates those jurisdictions have no affected EGUs. Also, as noted above, EPA is not proposing goals for tribes or U.S. territories at this time.

Table 3-1. Continued

Missouri	1,621	1,544	1,726	1,694
Montana	1,882	1,771	2,007	1,960
Nebraska	1,596	1,479	1,721	1,671
Nevada	697	647	734	713
New Hampshire	546	486	598	557
New Jersey	647	531	722	676
New Mexico *	1,107	1,048	1,214	1,176
New York	635	549	736	697
North Carolina	1,077	992	1,199	1,156
North Dakota	1,817	1,783	1,882	1,870
Ohio	1,452	1,338	1,588	1,545
Oklahoma	931	895	1,019	986
Oregon	407	372	450	420
Pennsylvania	1,179	1,052	1,316	1,270
Rhode Island	822	782	855	840
South Carolina	840	772	930	897
South Dakota	800	741	888	861
Tennessee	1,254	1,163	1,363	1,326
Texas	853	791	957	924
Utah *	1,378	1,322	1,478	1,453
Virginia	884	810	1,016	962
Washington	264	215	312	284
West Virginia	1,748	1,620	1,858	1,817
Wisconsin	1,281	1,203	1,417	1,380
Wyoming	1,808	1,714	1,907	1,869

* Excludes EGUs located in Indian country.

Table 3-2. Projected Base Case CO_2 Emissions Rate (Adjusted MWh-Weighted-Average Pounds of CO_2 Per Net MWh from all Affected Fossil Fuel-Fired EGUs)

State	2020	2025	2030
Alabama	1,491	1,511	1,557
Arizona*	1,458	1,439	1,523
Arkansas	1,563	1,576	1,577
California	691	692	633
Colorado	1,647	1,595	1,599
Connecticut	869	869	868
Delaware	1,076	1,104	937
Florida	1,211	1,285	1,345
Georgia	1,304	1,346	1,368
Idaho	544	596	592
Illinois	1,731	1,666	1,672
Indiana	1,938	1,791	1,753
Iowa	1,525	1,533	1,529
Kansas	1,833	1,795	1,790
Kentucky	2,163	2,165	2,168

Table 3-2. Continued

Louisiana	1,301	1,294	1,316
Maine	1,003	1,003	1,004
Maryland	1,746	1,747	1,721
Massachusetts	923	929	929
Michigan	1,794	1,829	1,826
Minnesota	1,697	1,687	1,695
Mississippi	1,053	1,078	1,144
Missouri	1,986	1,971	1,970
Montana	2,134	2,134	2,135
Nebraska	2,133	2,122	2,122
Nevada	989	876	879
New Hampshire	874	877	879
New Jersey	1,324	1,406	1,399
New Mexico*	1,396	1,246	1,330
New York	967	959	960
North Carolina	1,512	1,597	1,608
North Dakota	1,982	1,984	1,984
Ohio	1,704	1,777	1,794
Oklahoma	1,382	1,361	1,339
Oregon	531	503	536
Pennsylvania	1,566	1,639	1,684
Rhode Island	890	888	887
South Carolina	1,039	1,101	1,060
South Dakota	1,127	1,124	1,126
Tennessee	1,522	1,519	1,539
Texas	1,473	1,514	1,529
Utah*	1,829	1,749	1,800
Virginia	1,352	1,457	1,517
Washington	659	711	724
West Virginia	2,025	2,025	2,025
Wisconsin	1,935	1,944	1,938
Wyoming	2,053	2,054	2,055

* Excludes EGUs located in Indian country.

Note that the proposed state goals in Table 3-1 differ slightly from the state goals modelled in the illustrative compliance scenarios analyzed in this RIA. Any differences in the goals are minor and reflect small adjustments to the goal setting methodology due to minor adjustments in the assumed at-risk nuclear capacity, fossil units included in Indian Country, the treatment of cogeneration in historical data, and the assumed applicability for some units. The resulting changes to the state goals are minor, and any differences in results obtained by analyzing these new goals would be negligible. Furthermore, these small changes in the goals would be offset by comparable changes in the illustrative compliance scenarios (in which compliance is consistent with the assumptions used in setting state goals).

3.5 Compliance Scenarios Analyzed

In order to estimate the costs, benefits, and impacts of implementing the proposed guidelines, the EPA modeled two illustrative compliance scenarios. One of these scenarios allows averaging of emission rates within each individual state (these scenarios are referred to as "state"), and another set of scenarios where groups of states are assumed to collaborate and achieve compliance across larger regions (referred to as "regional"). Estimates of the benefits, costs, and economic impacts of this proposed action are presented for both state and regional compliance.[35] These illustrative compliance scenarios are designed to reflect, to the extent possible, the scope and nature of the proposed guidelines. However, there is considerable uncertainty with regard to the precise measures that states will adopt to meet the proposed requirements, since there are considerable flexibilities afforded to the states in developing their state plans. Nonetheless, the analysis of the benefits, costs, and relevant impacts of the proposed rule attempts to encapsulate some of those flexibilities in order to inform states and stakeholders of the potential overall impacts of the proposal. The relevant impacts, costs, and benefits are provided for 2020, 2025, and 2030 for Option 1 and 2020 and 2025 for Option 2 (with both state and regional compliance).

It is also important to note that the analysis does not specify any particular CO_2 reduction measure to occur, with the exception of the level of demand-side energy efficiency (EE), which the model is not currently configured to include as an endogenous compliance option. In other words, aside from EE, the analysis allows the power system the flexibility to respond to average emissions rate constraints on affected sources in the illustrative scenarios that achieve the state rate-based goals in the most cost-effective manner determined by IPM, as specified below.

In the illustrative compliance scenarios analyzed, the average emissions rate of the source types included in the calculation of the state goals must be, on average, less than or equal to the proposed goals over the entire compliance period. That is, the sources assumed to be directly

[35] For more details on the nature of the regulatory options, see the preamble.

affected by the illustrative state compliance scenarios are only those included in the calculation of the state goals, and include affected sources as well as savings from demand-side energy efficiency.[36] These affected sources are: [37]

- Existing fossil steam boilers with nameplate capacity greater than 25 MW
- Existing NGCC units with nameplate capacity greater than 25 MW
- Simple cycle combustion turbines with nameplate capacity greater than 25 MW, and 33% capacity factor and 219,000 MWh of generation in 2012
- New and existing non-hydro renewable capacity
- At risk and under construction nuclear.[38]

All compliance scenarios modeled include an assumption that affected sources within states are able to meet state goals collectively, by averaging all of their emissions relative to all of their generation. This approach enables some sources to emit at rates higher than the relevant goal, as long as there is corresponding generation coming from sources that emit at a lower rate such that the goal (in lbs/MWh) is met across all affected sources collectively. The average emissions rate at covered sources must be less than or equal to the applicable state goal, on average, over the entire compliance period, but not in any particular year.

The illustrative compliance scenarios further assume that the states adopt intertemporal averaging in the initial compliance period for both Option 1 and Option 2. That is, the average emissions rate at covered sources in each state must be less than or equal to the applicable state goal over the compliance period. The initial compliance period for Option 1 is 2020 to 2029 and for Option 2 it is 2020 to 2024. After the initial compliance period the average emission rate of

[36] As discussed in the preamble, for compliance purposes states may be able to include sources of generation in the calculation of the state's emission rate other than those sources of generation considered in constructing the building blocks for setting the state goals. However, this illustrative analysis does not include those options.

[37] For the illustrative scenarios renewable generation includes generation from wind, solar, geothermal, and biomass co-fired with coal. Dedicated biomass is not an affected source in the illustrative scenarios.

[38] See Greenhouse Gas Abatement Measures TSD

the affected sources in each year must be less than or equal to the state goal in the illustrative compliance scenarios.

For EE, the megawatt-hour (MWh) savings and associated costs are specified exogenously for Option 1 and Option 2 compliance scenarios consistent with the EE "best practice" performance levels informing calculation of state goals under each option. EPA has determined that these performance levels are achievable at costs that are generally less than avoided power system costs. EPA has specified and imposed EE-related costs and changes in future electricity demand exogenously when modeling the compliance scenarios presented for this rule. Details of the implementation of the demand reduction are reported in the following section.

EPA also analyzed a set of compliance scenarios that assume greater geographic flexibility for compliance where states may choose to cooperate in order to achieve more cost-effective outcomes, since some states can reduce their emissions more easily relative to others. This scenario is modeled for both Option 1 and Option 2 and is referred to as the “Regional” scenario. The regional scenarios allow emission rate averaging across affected sources within six multi-state regions, informed by North American Electric Reliability Corporation (NERC) regions and Regional Transmission Organizations (RTOs). These regions do not always follow state borders, however, so certain states that fall into more than one region were grouped in regions where there was a majority of geographic territory (area) or generation. While Florida and Texas each have unique NERC regions unto themselves, for purposes of this compliance analysis, those states were each grouped with other neighboring states:

- West (WECC) (CA, WA, OR, ID, MT, UT, NV, CO, WY, NM, AZ)
- North Central (MISO)[39] – ND, SD, IA, MN, WI, MO, IL, IN, MI
- South Central (SPP + ERCOT) – NE, KS, OK, AR, TX, LA
- Southeast (SERC + FL) – KY, NC, SC, TN, MS, AL, GA, FL
- East Central (PJM) – OH, PA, WV, MD, DE, NJ, VA

[39] Note that the MISO region expanded to integrate Entergy territory at the end of 2013.

- Northeast (NPCC) – NY, RI, MA, CT, NH, VT, ME

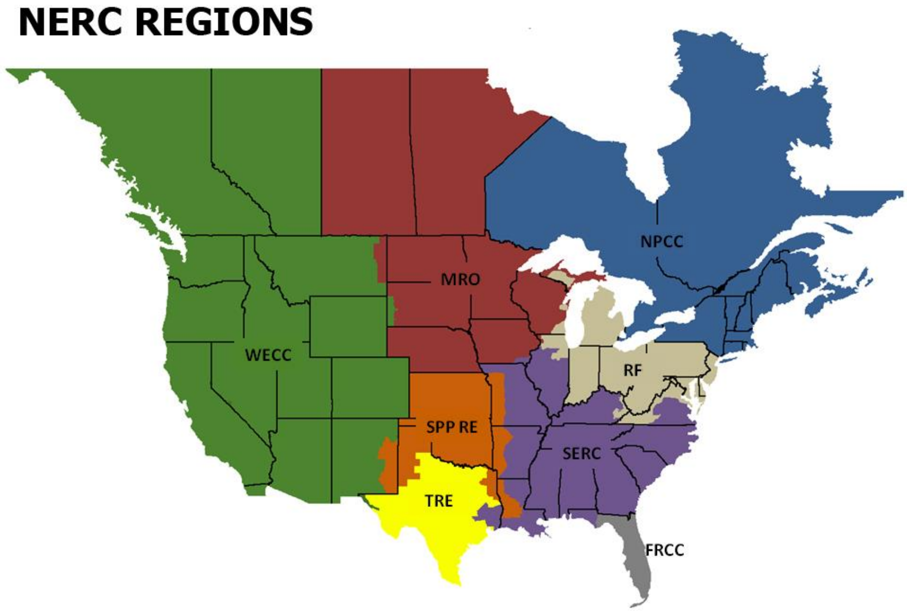

Figure 3-1. NERC Regions

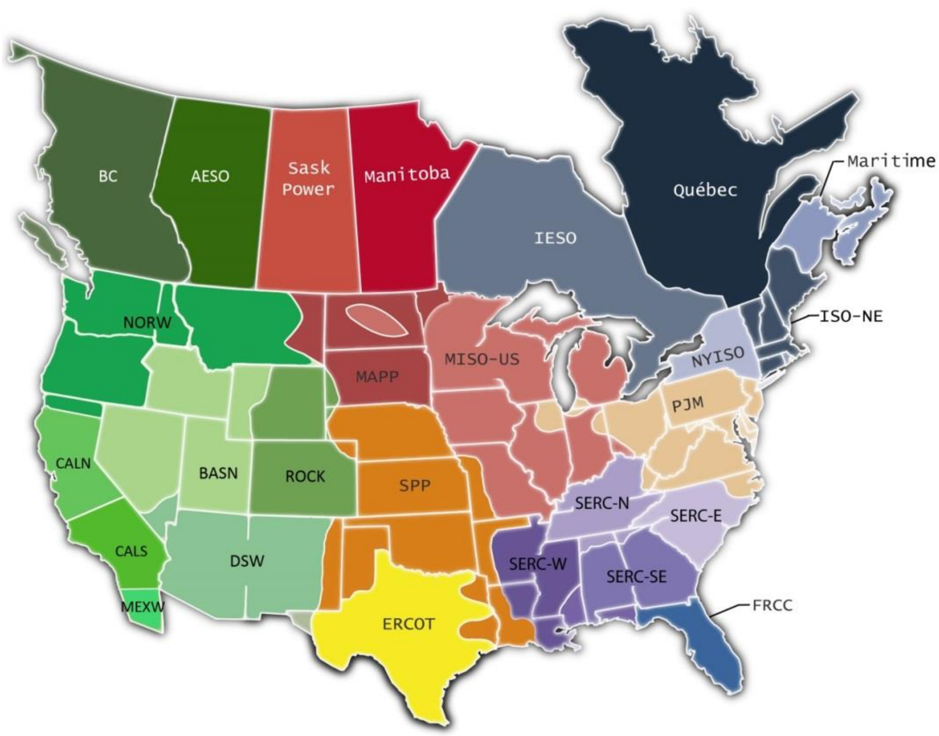

Figure 3-2. NERC Assessment Areas

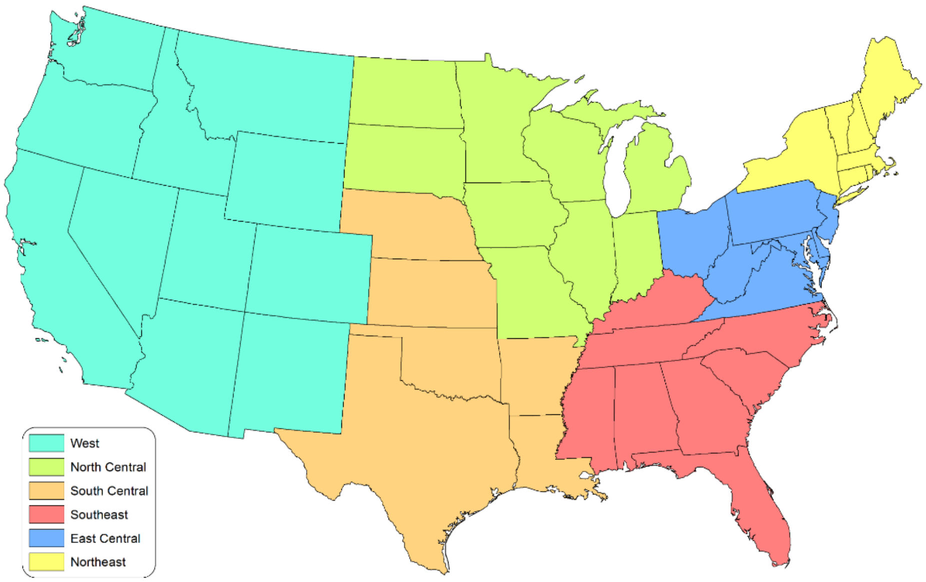

Figure 3-3. Regional Compliance Zones Used in this Analysis

These regional groupings of states allow the state goals in each option analyzed to be met collectively by averaging emission rate performance across all affected units located in that region. Results are also presented for "State" scenarios (for both options), to illustrate potential impacts and benefits should states choose not to cooperate in a "Regional" manner. In the regional scenarios, as in the state scenarios, affected sources in each state must respond to their respective state goal. However, the ability to average is extended to all affected sources in each compliance region. In these scenarios, the average emissions rate from affected sources in each region must be less than or equal to the weighted average[40] of the state goals in that region, over the compliance period. Furthermore, as in the "State" scenarios, the regions are assumed to adopt intertemporal averaging in the initial compliance period for each Option.

The analysis in the illustrative scenarios does not assume that states use any specific policy mechanism to achieve the state goals. While IPM produces a least cost solution to

[40] The weights are the generation of the covered sources plus the demand-side energy savings, in the respective state.

achieve the state goals imposed in the illustrative scenarios, there may be less costly approaches that the states may adopt to achieve their state goals.

In addition to these four illustrative compliance scenarios which estimate the costs and impacts of the proposed state goals, EPA also analyzed the impacts of the individual building blocks used to construct the proposed goals. For each of these additional scenarios, EPA imposed CO_2 emission rate constraints for each state that reflect the particular combination of building blocks analyzed in that scenario. The various building block combinations analyzed in these scenarios will be available in the docket for this rulemaking.

3.6 Demand Side Energy Efficiency

3.6.1 Projected Demand-Side Energy Savings[41]

To estimate the potential electricity demand reduction that could be achieved, and associated costs incurred, through implementation of demand-side energy efficiency policies, EPA developed scenarios that reflect increased levels of demand-side energy efficiency, rooted in what leading states have already accomplished or have requirements in place to accomplish.[42] For Option 1, adjustments were made to each state's annual incremental reduction in electricity consumption by ramping up from an historical basis[43] to a target rate of 1.5% of electricity demand annually over a period of years starting in 2017, and maintain that rate throughout the modeling horizon. Twelve leading states have either achieved, or have established requirements that will lead them to achieve, this rate of incremental electricity demand reduction, which we refer to as the "savings rate." The pace of improvement from the state's historical value is assumed to be 0.2% per year, beginning in 2017 until the target rate of reduction from baseline

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[41] For a more detailed discussion of the demand-side energy efficiency savings projections, refer to the Greenhouse Gas Abatement Measures TSD.

[42] This scenario is intended to represent a feasible pathway for additional EE resulting from accelerated use of energy efficiency policies, in all states, consistent with a level of performance that has already been demonstrated or required by policies (e.g., energy efficiency resource standards) of leading energy efficiency implementing states, and consistent with a demonstrated annual pace of performance improvement from current levels. It does not represent an estimate of the full potential for end-use EE.

[43] The historical basis of the percentage of reduced electricity consumption differs for each state and is drawn from the data reported in Energy Information Administration (EIA) Form 861, 2012, available at http://www.eia.gov/electricity/data/eia861/.

electricity demand is achieved. States already at or above the 1.5% annual incremental savings rate are assumed to have a 1.5% rate beginning in 2017 and sustain that rate. For Option 2, the annual incremental savings rate is ramped up from an historical basis to a target rate of 1.0% and at a pace of improvement of 0.15% per year, beginning in 2017, until the target rate is achieved. States already at or above the 1.0% annual incremental savings rate are assumed to sustain a 1.0% rate beginning in 2017. Twenty leading states have either achieved, or have established requirements that will lead them to achieve, this rate of savings. The incremental savings rate for each state, for each year, is then used to derive cumulative annual energy savings based upon information/assumptions about the average life of EE measures and the distribution of measure lives within a state's full portfolio of EE programs. The cumulative annual energy savings derived for Option 1 and Option 2 using this methodology are used consistently to set goals and to conduct power sector compliance modeling for each option.[44]

To reflect the implementation of demand-side energy efficiency in modeling, the fixed total electricity demand in IPM was adjusted exogenously to reflect the estimated future-year energy savings calculated from the approach described above. State energy savings in sales were scaled up to account for transmission losses and applied to base case generation demand in each model year to derive adjusted demand for each state, reflecting the energy efficiency scenario energy savings.[45] The demand adjustments were applied proportionally across all segments (peak and non-peak) of the load duration curve.[46] In order to reflect the adjusted state-level demand within IPM model regions that cross state borders, energy savings from a bisected state were distributed between the applicable IPM model regions using a distribution approach based on

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[44] See Greenhouse Gas Abatement Measures TSD and the State Goal Setting TSD

[45] That is, while the methodology for applying the energy efficiency savings rate was used consistently to set state goals and to conduct power sector compliance modeling for each option, the cumulative savings rate is applied to 2012 electricity consumption in the calculation of state goals whereas compliance modeling applies that rate to forecasted base case demand. Thus, for a given rate of demand reduction, the quantity of electricity demand reduced is greater in the compliance modeling than in setting the state goals, consistent with forecasted base case demand growth from 2012 to 2020 and beyond.

[46] For more information on load duration curves, see Chapter 2 of EPA's Base Case using IPM (v5.13) documentation, available at: http://www.epa.gov/powersectormodeling/BaseCasev513.html

reported sales in 2013 as a proxy for the distribution of energy efficiency investment opportunities.

Table 3-3. Net Cumulative Savings as a Percent of Projected BAU Sales

	Option 1			Option 2		
	2020	2025	2030	2020	2025	2030
Alabama	1.36%	6.19%	10.09%	1.07%	4.54%	n/a
Arizona	5.24%	9.50%	11.72%	3.52%	6.45%	n/a
Arkansas	1.52%	6.46%	10.31%	1.24%	4.77%	n/a
California	4.95%	9.46%	11.90%	3.55%	6.57%	n/a
Colorado	3.92%	8.73%	11.39%	3.32%	6.35%	n/a
Connecticut	4.71%	9.55%	12.27%	3.61%	6.77%	n/a
Delaware	1.14%	5.94%	10.14%	0.86%	4.32%	n/a
District of Columbia	1.14%	5.94%	10.14%	0.86%	4.32%	n/a
Florida	2.03%	7.04%	10.50%	1.75%	5.26%	n/a
Georgia	1.76%	6.74%	10.40%	1.48%	5.01%	n/a
Idaho	3.80%	8.73%	11.50%	3.28%	6.38%	n/a
Illinois	4.36%	9.26%	12.03%	3.52%	6.66%	n/a
Indiana	3.20%	8.42%	11.59%	2.89%	6.26%	n/a
Iowa	4.65%	9.39%	12.04%	3.58%	6.67%	n/a
Kansas	1.22%	6.05%	10.17%	0.94%	4.42%	n/a
Kentucky	1.91%	6.95%	10.57%	1.63%	5.18%	n/a
Louisiana	1.14%	5.88%	9.97%	0.85%	4.28%	n/a
Maine	5.37%	9.96%	12.48%	3.61%	6.77%	n/a
Maryland	4.21%	9.13%	11.92%	3.47%	6.61%	n/a
Massachusetts	4.43%	9.37%	12.18%	3.55%	6.73%	n/a
Michigan	4.59%	9.43%	12.16%	3.59%	6.73%	n/a
Minnesota	4.80%	9.49%	12.09%	3.58%	6.67%	n/a
Mississippi	1.40%	6.28%	10.20%	1.12%	4.62%	n/a
Missouri	1.58%	6.60%	10.53%	1.29%	4.88%	n/a
Montana	3.36%	8.41%	11.33%	3.01%	6.21%	n/a
Nebraska	2.20%	7.38%	10.95%	1.91%	5.51%	n/a
Nevada	2.95%	8.07%	11.15%	2.67%	6.00%	n/a
New Hampshire	2.84%	8.14%	11.52%	2.56%	6.08%	n/a
New Jersey	1.25%	6.10%	10.23%	0.96%	4.46%	n/a
New Mexico	3.10%	8.11%	11.03%	2.81%	6.02%	n/a
New York	4.42%	9.35%	12.17%	3.54%	6.73%	n/a
North Carolina	2.37%	7.45%	10.76%	2.09%	5.56%	n/a
North Dakota	1.39%	6.32%	10.35%	1.11%	4.65%	n/a
Ohio	4.17%	9.13%	11.97%	3.47%	6.63%	n/a
Oklahoma	1.86%	6.88%	10.54%	1.57%	5.13%	n/a
Oregon	4.66%	9.26%	11.76%	3.55%	6.55%	n/a
Pennsylvania	4.67%	9.42%	12.07%	3.58%	6.68%	n/a
Rhode Island	3.90%	9.02%	12.00%	3.35%	6.60%	n/a
South Carolina	2.32%	7.40%	10.73%	2.04%	5.52%	n/a
South Dakota	1.60%	6.62%	10.52%	1.32%	4.90%	n/a
Tennessee	2.21%	7.33%	10.79%	1.93%	5.47%	n/a

Table 3-3. Continued

Texas	1.78%	6.79%	10.48%	1.50%	5.05%	n/a
Utah	3.62%	8.62%	11.44%	3.19%	6.33%	n/a
Vermont	5.37%	9.96%	12.48%	3.61%	6.77%	n/a
Virginia	1.23%	5.98%	9.95%	0.95%	4.37%	n/a
Washington	4.24%	9.01%	11.64%	3.45%	6.49%	n/a
West Virginia	1.77%	6.86%	10.71%	1.49%	5.11%	n/a
Wisconsin	4.68%	9.48%	12.17%	3.60%	6.73%	n/a
Wyoming	1.61%	6.55%	10.32%	1.33%	4.85%	n/a
Contiguous U.S. Total	3.05%	7.93%	11.14%	2.44%	5.76%	n/a
Alaska	1.22%	6.02%	10.09%	0.94%	4.40%	n/a
Hawaii	1.29%	6.13%	10.15%	1.01%	4.49%	n/a
U.S. Total	3.04%	7.92%	11.13%	2.43%	5.75%	n/a

Source: See Greenhouse Gas Abatement Measures TSD

3.6.2 Demand-Side Energy Efficiency Total Costs[47]

Total costs of achieving the demand-side energy efficiency scenarios for each year were determined at the state level, exogenous to power sector modeling. In addition to the energy savings data, the total cost was based upon first-year cost of saved energy, average measure life, distribution of measure lives, and cost escalation factors.

The first year cost of saved energy used in the cost calculation accounts for both the costs to the utilities that are funding the demand-side energy efficiency programs (known as the program costs), and the additional cost to the end-user purchasing a more energy efficient technology (known as the participant costs). Total costs were found to be divided evenly, 50% each, between program costs and participant costs.[48] To account for the potential for increasing costs as states realize greater levels of energy savings, the first-year costs were escalated when the annual incremental savings in each state reached 0.5% (a 20% additional cost escalation is applied to subsequent investments) and a 1.0% (a 40% additional cost escalation is applied to subsequent investments).

[47] For a more detailed discussion of the demand-side energy efficiency savings cost estimates, refer to the Greenhouse Gas Abatement Measures TSD.

[48] For a more detailed discussion of the analysis of program versus participant costs, refer to the Greenhouse Gas Abatement Measures TSD.

To calculate total annualized energy efficiency costs, first-year costs for each year for each state were levelized (at 3% and 7% discount rates) over the estimated distribution of measure lives and the results summed for each year for each state. For example, the 2025 estimate of annualized EE cost includes levelized value of first-year costs for 2017 through 2025. The annualized cost is rising in each analysis year as additional first-year costs are incurred. These annualized costs were determined for Options 1 and 2 and are summarized below in Table 3-4. The total levelized cost of saved energy was calculated based upon the same inputs and using a 3% discount rate results in average values of 8.5 cents per kWh in 2020, 8.9 cents per kWh in 2025, and 9.0 cents per kWh in 2030.[49]

The utility funding for demand-side energy efficiency programs (to cover program costs) is typically collected through a standard per kWh surcharge to the rate-payer; the regional retail price impacts analyzed from this RIA's compliance scenarios assumes the recovery of these program costs through the following procedure.[50] For each state, the first-year EE program costs are calculated for each year (which are equal to 50% of the total first-year EE costs for that state as noted above). These EE program costs were distributed between the applicable IPM model regions using a distribution approach based on reported sales in 2013 as a proxy for the distribution of energy efficiency investment opportunities. These regionalized EE program costs were then incorporated into the regional retail price calculation as discussed in section 3.7.9. [51]

[49] This analysis does not capture the potential effect on the quantity of electricity demand of lower electricity prices induced by energy efficiency policies. That is, the modeling does not capture a "system wide" rebound effect of energy efficiency policies. This is due to IPM's assumption of fixed demand. However, the modeling also does not capture the effect of higher costs of producing electricity, which is attributable to other methods of complying with the state goals, on electricity demand for the same reason (i.e., fixed demand in IPM). For further discussion of these issues see the Limitations section at the end of this chapter.

[50] The full retail price analysis method is discussed in section 3.7.9 of this chapter.

[51] The effect on equilibrium supply and demand of electricity due to changing retail rates to fund energy efficiency programs is not captured in the IPM modeling.

Table 3-4. Annualized Cost of Demand-Side Energy Efficiency (at discount rates of 3% and 7%, billions 2011$)

	2018	2020	2025	2030
Option 1 at 3%	4.1	10.2	28.9	42.7
Option 1 at 7%	4.9	12.3	35.0	51.8
Option 2 at 3%	3.6	8.0	20.6	n/a
Option 2 at 7%	4.3	9.7	24.9	n/a

Source: Greenhouse Gas Abatement Measures TSD

Annualized demand-side energy efficiency (EE) costs are derived by using two key variables: the first-year (or "up front") EE costs and EE investment lives (which vary by type of program). Chapter 5 of the GHG Abatement Measures TSD presents the calculations of annualized costs as well as a comprehensive set (by state, by year) of first-year EE costs.

3.7 Projected Power Sector Impacts

3.7.1 Projected Emissions

Under the proposed rule, EPA projects annual CO_2 reductions between 17% and 18% below base case projections for Option 1 in 2020 (reaching 26% to 27% below 2005 emissions[52]), and between 24% and 25% below the base case in 2030 (reaching 30% below 2005 emissions). For Option 2, EPA projects annual CO_2 reductions between 13% and 14% in 2020 (reaching 23% below 2005 emissions) and 17% in 2025 (reaching 23% to 24% below 2005 emissions). For each Option, the regional scenario achieves fewer emissions reductions largely because the ability to average emissions regionally allows those states that were projected to emit below their state goal in the base case to offset reductions that other states would otherwise have made.

[52] For purposes of these calculations, EPA has used historical CO_2 emissions from eGRID for 2005, which reports EGU emissions as 2,434 million metric tonnes in the contiguous US.

Table 3-5. Projected CO_2 Emission Impacts, Relative to Base Case

	CO_2 Emissions (MM Tonnes)			CO_2 Emissions Change from Base Case (MM Tonnes)			CO_2 Emissions: Percent Change from Base Case		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**	**2020**	**2025**	**2030**
Base Case	2,161	2,231	2,256						
Option 1 Regional	1,790	1,730	1,711	-371	-501	-545	-17%	-22%	-24%
Option 1 State	1,777	1,724	1,701	-383	-506	-555	-18%	-23%	-25%
Option 2 Regional	1,878	1,862	n/a	-283	-368	n/a	-13%	-17%	n/a
Option 2 State	1,866	1,855	n/a	-295	-376	n/a	-14%	-17%	n/a

Source: Integrated Planning Model run by EPA, 2014

Table 3-6. Projected CO_2 Emission Impacts, Relative to 2005

	CO_2 Emissions (MM Tonnes)			CO_2 Emissions Change from 2005 (MM Tonnes)			CO_2 Emissions: Percent Change from 2005		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**	**2020**	**2025**	**2030**
Base Case	2,161	2,231	2,256	-273	-203	-178	-11%	-8%	-7%
Option 1 Regional	1,790	1,730	1,711	-644	-704	-723	-26%	-29%	-30%
Option 1 State	1,777	1,724	1,701	-657	-710	-733	-27%	-29%	-30%
Option 2 Regional	1,878	1,862	n/a	-556	-572	n/a	-23%	-23%	n/a
Option 2 State	1,866	1,855	n/a	-568	-579	n/a	-23%	-24%	n/a

Source: Integrated Planning Model run by EPA, 2014

In 2020, EPA projects a 20% to 23% reduction of SO_2, 22% to 24% reduction of NO_X, and a 15% to 18% reduction of mercury, under the proposed Option 1 illustrative scenarios. EPA projects fewer emission reductions overall as a result of the proposed Option 2 in 2020: a 17% to 18% reduction in SO_2, 17% to 18% reduction in NO_X, and an 11% to 14% reduction in mercury. The projected non-CO_2 reductions presented in Table 37 below demonstrate similar trends in later years.

Table 3-7. Projected Non-CO_2 Emission Impacts, 2020-2030

	Base Case	Option 1 Reg.	Option 1 State	Option 2 Reg.	Option 2 State	Option 1 Reg.	Option 1 State	Option 2 Reg.	Option 2 State
2020									
SO_2 (thousand tons)	1,476	1,184	1,140	1,231	1,208	-19.8%	-22.7%	-16.6%	-18.1%
NO_X (thousand tons)	1,559	1,213	1,191	1,290	1,277	-22.2%	-23.6%	-17.2%	-18.0%
Hg (tons)	8.3	7.0	6.8	7.3	7.1	-15.3%	-18.1%	-11.3%	-14.0%
$PM_{2.5}$ (thousand tons)	212	156	154	166	163	-26.4%	-27.2%	-21.5%	-22.9%
2025									
SO_2 (thousand tons)	1,515	1,120	1,090	1,218	1,188	-26.1%	-28.0%	-19.6%	-21.6%
NO_X (thousand tons)	1,587	1,166	1,151	1,279	1,271	-26.5%	-27.5%	-19.4%	-19.9%
Hg (tons)	8.7	7.0	6.7	7.4	7.1	-19.5%	-23.2%	-14.9%	-19.3%
$PM_{2.5}$ (thousand tons)	209	150	146	165	161	-28.1%	-30.1%	-21.0%	-23.2%
2030									
SO_2 (thousand tons)	1,530	1,106	1,059	n/a	n/a	-27.7%	-30.8%	n/a	n/a
NO_X (thousand tons)	1,537	1,131	1,109	n/a	n/a	-26.4%	-27.9%	n/a	n/a
Hg (tons)	8.8	7.0	6.6	n/a	n/a	-19.7%	-24.1%	n/a	n/a
$PM_{2.5}$ (thousand tons)	198	144	142	n/a	n/a	-27.2%	-28.5%	n/a	n/a

Source: Integrated Planning Model run by EPA, 2014

While the EPA has not quantified the climate impacts of these other pollutants for the proposed guidelines, the Agency has analyzed the potential changes in upstream methane emissions from the natural gas and coal production sectors that may result from the compliance approaches examined in this RIA. The EPA assessed whether the net change in upstream methane emissions from natural gas and coal production is likely to be positive or negative and also assessed the potential magnitude of changes relative to CO_2 emissions reductions anticipated at power plants. This assessment included CO_2 emissions from the flaring of methane, but did not evaluate potential changes in other combustion-related CO_2 emissions, such as emissions associated with drilling, mining, processing, and transportation in the natural gas and coal production sectors. This analysis found that the net upstream methane emissions from natural gas systems and coal mines and CO_2 emissions from flaring of methane will likely decrease under the proposed guidelines. Furthermore, the changes in upstream methane emissions are small relative to the changes in direct emissions from power plants. The technical details supporting this analysis can be found in the Appendix to this chapter.

3.7.2 Projected Compliance Costs

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the base case and policy case in which the sector pursues flexible compliance approaches to meet the proposed rule as represented in the illustrative compliance scenarios. In simple terms, these costs are the resource costs of what the power industry will expend to comply with EPA's requirements. [53] Program and participant end-use EE costs are also included in the compliance cost estimates.

EPA projects that the annual compliance cost of the proposed rule's Option 1 ranges from $5.4 to $7.4 billion in 2020 and from $7.3 to $8.8 billion in 2030. The projected annual incremental compliance cost of the proposed rule's Option 2 ranges from $4.2 to $5.4 billion in 2020 and from $4.5 to $5.5 billion in 2025. The annual compliance cost is the projected additional cost of complying with the proposed rule in the year analyzed and includes the net change in the annualized cost of capital investment in new generating sources and heat rate improvements at coal steam facilities,[54] the change in the ongoing costs of operating pollution controls, shifts between or amongst various fuels, demand-side energy efficiency measures, and other actions associated with compliance.

Table 3-8. Annualized Compliance Costs (billions of 2011$)

	2020	2025	2030
Option 1 Regional	5.4	4.6	7.3
Option 1 State	7.4	5.5	8.8
Option 2 Regional	4.2	4.5	n/a
Option 2 State	5.4	5.5	n/a

These costs do not include monitoring, reporting, and recordkeeping costs. For more information, see section 3.11.
Source: Integrated Planning Model run by EPA, 2014 and with post-processing to account for exogenous demand side management energy efficiency costs. See Chapter 5 of GHG Abatement Measures TSD for a full explanation.

[53] The compliance costs also capture the effect of changes in equilibrium fuel prices on the expenditures of the electricity sector to serve demand.

[54] See Chapter 2 of the Greenhouse Gas Abatement Measures TSD and Chapter 8 of EPA's Base Case using IPM (v5.13) documentation, available at: http://www.epa.gov/powersectormodeling/BaseCasev513.html

EPA's projection of $4.2 to $7.4 billion in additional costs in 2020 across the illustrative compliance scenarios evaluated for both options should be put into context for power sector operations. As shown in section 2.7, the power sector is expected in the base case to expend over $359 billion in 2020 to generate, transmit, and distribute electricity to end-use consumers. Therefore, the projected costs of compliance with the proposed rule amount to a one to two percent increase in the cost to meet electricity demand, while securing public health and welfare benefits that are several times more valuable (as described in Chapters 4 and 8).

The annual compliance costs presented in Table 3 reflects the cost savings due to reduced electricity demand from energy efficiency measures presented earlier.

The following example uses results from Option 1 Regional scenario in the year 2020 to illustrate how different components of estimated expenditures are combined to form the full compliance costs presented in Table 3. In Table 3-8 we present the IPM modeling results for the 2020 Option 1 Regional scenario, which includes CO_2 emission reductions from the four building blocks and the exogenous reductions in electricity demand due to end-use energy efficiency (EE) improvements, and the base case. The results show that annualized expenditures required to supply enough electricity to meet demand decline by $4.8 billion from the base case. This incremental decline is a net outcome of two simultaneous effects which move in opposite directions. First, imposing the CO_2 constraints represented in the Option 1 Regional scenario on electric generators would, other things equal, result in an incremental increase in expenditures to supply any given level of electricity. However, once electricity demand is exogenously reduced in IPM to reflect the substantial reduction in electricity demand (induced by EE improvements), there is a substantial reduction in the expenditures needed to supply a correspondingly lower amount of electricity demand.

Table 3-9. Total Power Sector Generating Costs (IPM) (billions 2011$)

	2020	2025	2030
Base Case	$177.8	$202.9	$224.7
Option 1 Regional	$173.0	$178.6	$189.2
Option 1 State	$175.0	$179.5	$190.7
Option 2 Regional	$174.0	$186.9	n/a
Option 2 State	$175.2	$187.8	n/a

Source: Integrated Planning Model run by EPA, 2014

In order to reflect the full compliance cost attributable to the policy, it is necessary to include this incremental -$4.8 billion in electricity supply expenditures with the annualized expenditures needed to secure the end-use energy efficiency improvements. EPA has estimated these EE-related expenditures to be $10.2 billion in 2020 (using a 3% discount rate). As a result, this analysis finds the cost of the Option 1 Regional scenario in 2020 to be $5.4 billion (the sum of incremental supply-related and demand-related expenditures).[55]

3.7.3 Projected Compliance Actions for Emissions Reductions

Heat rate improvements (HRI). EPA analysis assumes that the existing coal steam electric generating fleet has, on average, the ability to improve operating efficiency (i.e., reduce the average net heat rate, or the Btu of fuel energy needed to produce one kWh of net electricity output). All else held constant, HRI allow the EGU to generate the same amount of electricity using less fuel. The decrease in required fossil fuel results in a lower output-based CO_2 emissions rate (lbs/MWh), as well as a lower variable cost of electricity generation. In the modeling conducted for these compliance scenarios, coal boilers have the choice to improve heat rates by 6% under Option 1 and 4% under Option 2, at capital cost of $100 per kW in both options.[56]

The vast majority of existing coal boilers are projected to adopt the aforementioned heat rate improvements. EPA projects that 176 to 179 GW of existing coal steam capacity (greater than 25 MW) will improve operating efficiency (i.e., reduce the average net heat rate) under Option 1 in 2020. Under Option 2, EPA projects that 168 to 185 GW of existing coal steam capacity with improve operating efficiency in 2020.

Re-dispatch. Another approach for reducing the average emission rate from existing units is to shift some generation from more CO_2-intensive generation to less CO_2-intensive generation. Compared to the Base Case, existing coal steam capacity is projected to operate at a lower capacity factor for both Option 1 and Option 2, on average, although projected average capacity factors for existing coal steam boilers remains around 75% across scenarios. Existing natural gas

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[55] For this analysis, we quantified and imposed end-use EE costs and impacts on electricity demand exogenously.

[56] The option for heat rate improvement is only made available in the illustrative scenarios for Options 1 and 2, and is not available in the base case. See GHG Abatement Measures TSD.

combined cycle units, which are less carbon-intensive than coal steam capacity on an output basis, operate at noticeably higher capacity factor in Options 1 and 2, on average. See Table 3-2. The utilization of existing natural gas combined cycle capacity is lower than 70% on an annual average basis in these illustrative compliance scenarios, reflecting the fact that states have the flexibility to choose among alternative CO_2 reduction strategies that were part of BSER, instead of employing re-dispatch to the maximum extent. In addition, future electric demand is considerably lower than the Base Case.

Table 3-10. Projected Capacity Factor of Existing Coal Steam and Natural Gas Combined Cycle Capacity

	Existing Coal Steam			Existing Natural Gas Combined Cycle		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
Base Case	78%	80%	79%	52%	48%	42%
Option 1 Regional	77%	74%	73%	55%	54%	50%
Option 1 State	76%	74%	73%	56%	55%	51%
Option 2 Regional	75%	74%	n/a	57%	55%	n/a
Option 2 State	75%	73%	n/a	57%	56%	n/a

Source: Integrated Planning Model run by EPA, 2014

Demand-Side Energy Efficiency. Another approach for reducing the average emission rate is to consider reductions in load attributable to demand-side energy efficiency savings, which will reduce the need for higher emitting generation.[57] In the compliance scenario analyses presented in this RIA, each state is credited for total demand-side energy efficiency savings consistent with the savings that are used to construct the state goals. See section 3.6.1 for a description of the levels assumed for Options 1 and 2. Again, these reductions in demand as a result of demand-side energy efficiency are made exogenously in both of the Options for the illustrative scenarios analyzed.

3.7.4 Projected Generation Mix

Table 3-3 and Figure 3-4 show the generation mix in the base case and under the proposed rule. The ability to average the emissions rate at covered sources (which exclude new

[57] Because fossil fuel-fired EGUs typically have higher variable costs than other EGUs (such as nuclear and renewable EGUs), they are typically the first to be displaced when demand is reduced. The influence of EE on new sources of generation depends on both their relative variable and capital costs.

NGCC) over the 2020-2030 compliance period provides an incentive to shift generation within the covered sources to less carbon-intensive generation. In 2020, for Option 1, total generation declines approximately three percent under Option 1 as a result of the reduction in total demand attributable to the demand-side energy savings applied in the illustrative scenarios. Coal-fired generation is projected to decline 20% to 22% in 2020, and natural-gas-fired generation from existing combined cycle capacity is projected to increase four to six percent relative to the base case under Option 1. In 2030, the cumulative demand-side energy savings under the Option 1 result in an 11% reduction in total generation relative to the base case. The coal-fired fleet in 2030 generates between 25% and 27% less than in the base case, while natural-gas-fired generation from existing combined cycles increases 18% to 19% relative to the base case. Gas-fired generation from new combined cycle capacity increases in 2020, as projected new natural gas combined cycle capacity replaces retired coal capacity. By 2030, generation from newly built natural gas combined cycle decreases between 36% and 40% relative to the base case, consistent with the decrease in new capacity (see section 3.7.6). Generation from non-hydro renewables increases two percent relative to the base case in 2030.

Similar trends are projected for Option 2. In 2020, total generation declines two percent under Option 2 as a result of the reduction in total demand attributable to the demand-side energy savings applied in the illustrative scenarios. Coal generation is projected to decrease between 16% and 17% in 2020, and natural gas-fired generation from existing combined cycle units is projected to increase nine percent, relative to the base case.

Under both options, additional natural gas pipeline capacity is projected to be built through 2020 relative to the base case. In all of the illustrative compliance scenarios, pipeline capacity is projected to increase four to eight percent beyond base case projections by 2020. In 2030, however, the total cumulative pipeline capacity built is projected to decrease, consistent with the projected decrease in total natural gas use. The projected increase in pipeline capacity in the near term is largely the result of building pipeline capacity a few years earlier than in is projected in the base case. Given the relatively small amount of additional infrastructure development that is projected to shift to earlier years, construction of this additional capacity should be easily manageable and not raise any reliability or cost concerns.

Table 3-11. Generation Mix (thousand GWh)

	Base Case	Option 1		Option 2		Option 1		Option 2	
		Reg.	State	Reg.	State	Reg.	State	Reg.	State
2020									
Pulverized Coal	1,665	1,337	1,302	1,406	1,375	-20%	-22%	-16%	-17%
NG Combined Cycle (existing)	1,003	1,043	1,065	1,093	1,091	4%	6%	9%	9%
NG Combined Cycle (new)	85	238	248	155	185	181%	192%	83%	119%
Combustion Turbine	19	33	33	33	32	74%	76%	75%	67%
Oil/Gas Steam	52	15	14	18	16	-70%	-73%	-65%	-69%
Non-Hydro Renewables	299	321	323	313	316	7%	8%	5%	5%
Hydro	280	282	281	282	281	1%	1%	1%	1%
Nuclear	817	817	819	814	819	0%	0%	0%	0%
Other	8	15	14	13	12	92%	88%	66%	61%
Total	4,227	4,102	4,100	4,128	4,128	-3%	-3%	-2%	-2%
2025									
Pulverized Coal	1,702	1,275	1,250	1,383	1,353	-25%	-27%	-19%	-20%
NG Combined Cycle (existing)	919	1,022	1,035	1,055	1,068	11%	13%	15%	16%
NG Combined Cycle (new)	280	257	266	218	231	-8%	-5%	-22%	-17%
Combustion Turbine	27	37	37	37	37	36%	39%	36%	36%
Oil/Gas Steam	37	13	15	16	16	-64%	-59%	-56%	-58%
Non-Hydro Renewables	335	347	346	342	341	4%	3%	2%	2%
Hydro	280	282	281	282	282	1%	0%	0%	0%
Nuclear	817	817	819	814	819	0%	0%	0%	0%
Other	6	13	11	11	10	115%	86%	71%	64%
Total	4,404	4,063	4,062	4,158	4,156	-8%	-8%	-6%	-6%
2030									
Pulverized Coal	1,668	1,249	1,216	n/a	n/a	-25%	-27%	n/a	n/a
NG Combined Cycle (existing)	810	955	961	n/a	n/a	18%	19%	n/a	n/a
NG Combined Cycle (new)	599	359	384	n/a	n/a	-40%	-36%	n/a	n/a
Combustion Turbine	23	32	31	n/a	n/a	43%	35%	n/a	n/a
Oil/Gas Steam	23	10	12	n/a	n/a	-57%	-46%	n/a	n/a
Non-Hydro Renewables	350	356	356	n/a	n/a	2%	2%	n/a	n/a
Hydro	280	281	280	n/a	n/a	0%	0%	n/a	n/a
Nuclear	797	796	797	n/a	n/a	0%	0%	n/a	n/a
Other	6	16	14	n/a	n/a	163%	132%	n/a	n/a
Total	4,557	4,054	4,051	n/a	n/a	-11%	-11%	n/a	n/a

Note: “Other” mostly includes MSW and fuel cells. Source: Integrated Planning Model run by EPA, 2014

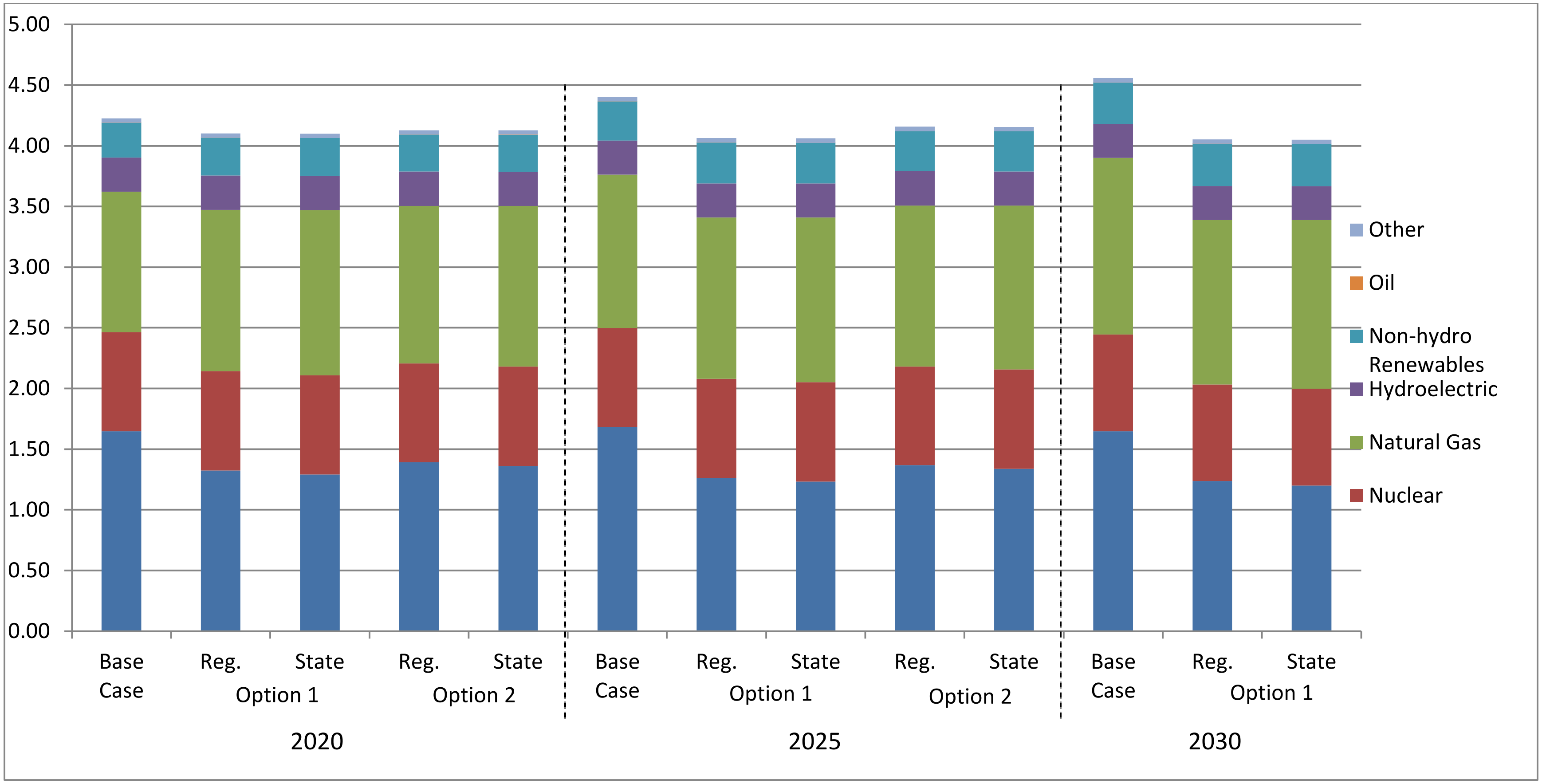

Figure 3-4. Generation Mix with the Base Case and 111(d) Options, 2020-2030 (million GWh)
Source: Integrated Planning Model run by EPA, 2014

3.7.5 Projected Incremental Retirements

Relative to the base case, about 30 to 49 GW of coal-fired capacity is projected to be uneconomic to maintain (about 12% to 19% of all coal-fired capacity projected to be in service in the base case) by 2020 under the range of scenarios analyzed.

For the proposed rule, EPA examined whether these projected incremental retirements may adversely impact reserve margins and reliability planning. The IPM model is designed to ensure that generation resource adequacy is maintained in the projected results, and the model is required to meet reserve margin requirements in the 64 modeling regions in the contiguous US by retaining enough existing capacity and/or building enough new capacity. IPM also addresses reliable delivery of generation resources at a regional level by limiting the ability to transfer power between regions using the bulk power transmission system. Within each model region, IPM assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region.[58]

EPA examined the implications of each of the scenarios for regional resource adequacy and for potential concerns over on grid reliability. To conduct this analysis, EPA examined key parameters from the IPM projections to assess whether concerns over regional resource adequacy would be likely to arise or whether changes in generation and flow pattern impacts would raise issues for reliability management. The key parameters analyzed were:

Operating Reserve Margins. The IPM model ensures that target reserve margins from NERC will be met, by maintaining existing capacity or by building additional new capacity if needed. Capacity that is otherwise uneconomic to operate will be retired only when planned reserve margins can be met from within the region or by transfers from other regions.

Operational Capacity. Since IPM ensures that NERC target margins will be met, EPA analyzed the remaining operating capacity for 2020 through 2030 to determine what types of changes in the generation fleet were projected to occur through retirements, additional generation and energy efficiency. Although there were changes from the base case to the policy cases, none of

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[58] For more detail on IPM's electric load modeling and power system operation, please see IPM documentation (http://www.epa.gov/powersector modeling).

the policy cases were found to raise concerns over regional resource adequacy. Moreover, the time horizon for compliance with this rule will permit environmental and reliability planners to coordinate these changes and address potential concerns before they arise.

Interregional Power Flows and Capacity Transfers. IPM constrains both interregional energy flows and interregional transfers of capacity to meet reserve requirements. These limits are based on grid operator data from ISOs, RTOs and other planning entities. Although these limits keep projected flows within expected bounds, EPA further examined how the policy options impacted these flows and transfers to identify any large shifts from the base case. None of the interregional changes in the policy cases suggested that there would be increases in flows that would raise significant concerns about grid congestion or grid management.

The increased energy efficiency anticipated with the proposed rule also contributes to meeting resource adequacy, by lowering the regional load and thereby lowering operating capacity needed to meet planning reserve margins. Demand-side energy efficiency would also reduce the overall load on the grid and thus generally reduces the burden on the transmission infrastructure needed to maintain reliability. EPA concludes that the proposed rule will not raise significant concerns over regional resource adequacy or raise the potential for interregional grid problems. EPA believes any remaining local issues can be managed through standard reliability planning processes.[59]

Capacity changes from the base case in 2020 are shown in Table 3-12.

[59] For further discussion of EPA's examination of these projected incremental retirements on reserve margins and reliability planning, see the Resource Adequacy and Reliability Analysis TSD.

Table 3-12. Total Generation Capacity by 2020-2030 (GW)

	Base Case	Option 1		Option 2		Option 1		Option 2	
		Reg.	State	Reg.	State	Reg.	State	Reg.	State
2020									
Pulverized Coal	244	198	195	214	211	-19%	-20%	-12%	-14%
NG Combined Cycle (existing)	219	216	217	218	218	-1%	-1%	-1%	0%
NG Combined Cycle (new)	12	33	35	21	26	174%	190%	79%	117%
Combustion Turbine	146	144	143	146	145	-2%	-2%	-1%	-1%
Oil/Gas Steam	83	66	66	72	71	-20%	-20%	-13%	-14%
Non-Hydro Renewables	93	105	105	101	102	13%	13%	9%	10%
Hydro	101	101	101	101	101	0%	0%	0%	0%
Nuclear	103	103	103	103	103	0%	0%	0%	0%
Other	5	5	5	5	5	2%	2%	2%	2%
Total	1,005	971	970	981	981	-3%	-3%	-2%	-2%
2025									
Pulverized Coal	243	197	193	214	211	-19%	-21%	-12%	-13%
NG Combined Cycle (existing)	219	216	217	218	218	-1%	-1%	-1%	0%
NG Combined Cycle (new)	39	34	36	30	32	-11%	-7%	-23%	-18%
Combustion Turbine	149	145	144	148	147	-3%	-3%	-1%	-2%
Oil/Gas Steam	82	65	66	72	71	-20%	-19%	-12%	-13%
Non-Hydro Renewables	103	113	112	110	110	10%	8%	7%	7%
Hydro	101	101	101	101	101	0%	0%	0%	0%
Nuclear	103	103	103	103	103	0%	0%	0%	0%
Other	5	5	5	5	5	2%	2%	2%	2%
Total	1,044	980	977	1,000	997	-6%	-6%	-4%	-4%
2030									
Pulverized Coal	240	195	191	n/a	n/a	-19%	-21%	n/a	n/a
NG Combined Cycle (existing)	219	216	217	n/a	n/a	-1%	-1%	n/a	n/a
NG Combined Cycle (new)	84	49	52	n/a	n/a	-42%	-38%	n/a	n/a
Combustion Turbine	156	146	145	n/a	n/a	-7%	-7%	n/a	n/a
Oil/Gas Steam	82	65	66	n/a	n/a	-20%	-19%	n/a	n/a
Non-Hydro Renewables	107	117	115	n/a	n/a	9%	7%	n/a	n/a
Hydro	101	101	101	n/a	n/a	0%	0%	n/a	n/a
Nuclear	101	100	101	n/a	n/a	0%	0%	n/a	n/a
Other	5	5	5	n/a	n/a	2%	2%	n/a	n/a
Total	1,095	994	992	n/a	n/a	-9%	-9%	n/a	n/a

Source: Integrated Planning Model run by EPA, 2014

3.7.6 Projected Capacity Additions

Due largely to the demand reduction attributable to the demand-side energy savings applied in the illustrative scenarios, EPA projects less new natural gas combined cycle capacity built under the proposed rule than is built in the base case over the time horizon presented in this

RIA. While this new NGCC capacity cannot be directly counted towards the average emissions rate used for compliance, it can displace some generation from covered sources and thus indirectly lower the average emissions rate from covered sources. Conversely, EPA projects an overall increase in new non-hydro renewable capacity. As affected sources in the illustrative scenarios, the generation from new non-hydro renewables are able to contribute to the average emissions rate in each state or region.

Under the Option 1 illustrative scenarios, new natural gas combined cycle capacity is projected to increase by 21 to 23 GW in 2020 (174% to 190% increase relative to the base case), and decrease by 32 to 35 GW (38% to 42% reduction relative to base case) by 2030. New non-hydro renewable capacity is projected to increase by about 12 GW (67% increase) above the base case in 2020, and 8 to 9 GW (24% to 28% increase) by 2030.

Under the Option 2 illustrative scenarios, new natural gas combined cycle capacity is projected to increase by about 9 to 14 GW (79% to 117% increase relative to base case) in 2020, and decrease between 7 and 9 GW (17% to 23% reduction) in 2025. New non-hydro renewable capacity is projected to increase by about 9 GW (50% increase) above the base case in 2020, and about 7 GW (25% increase) by 2025.

Table 3-13. Projected Capacity Additions, Gas (GW)

	Cumulative Capacity Additions: Gas Combined Cycle			Incremental Cumulative Capacity Additions: Gas Combined Cycle		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
Base Case	11.9	38.9	83.8			
Option 1 Regional	32.7	34.4	49.0	20.8	-4.4	-34.8
Option 1 State	34.7	36.1	51.6	22.7	-2.7	-32.1
Option 2 Regional	21.4	30.0	n/a	9.4	-8.9	n/a
Option 2 State	25.9	32.0	n/a	14.0	-6.8	n/a

Source: Integrated Planning Model run by EPA, 2014

Table 3-14. Projected Capacity Additions, Non-hydro Renewable (GW)

	Cumulative Capacity Additions: Renewables			Incremental Cumulative Capacity Additions: Renewables		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
Base Case	17.8	28.4	32.7			
Option 1 Regional	29.9	38.4	41.9	12.1	9.9	9.2
Option 1 State	29.6	37.0	40.6	11.8	8.5	7.9
Option 2 Regional	26.4	35.5	n/a	8.6	7.1	n/a
Option 2 State	26.7	35.0	n/a	8.8	6.6	n/a

Source: Integrated Planning Model run by EPA, 2014

3.7.7 Projected Coal Productions for the Electric Power Sector

Coal production is projected to decrease in 2020 and beyond in the illustrative scenarios due to (1) improved heat rates (generating efficiency) at existing coal units, (2) demand reduction attributable to the demand-side energy savings, and (3) a shift in generation from coal to less-carbon intensive generation. As shown in Table 3-15, the largest decrease in coal production on a tonnage basis is projected to occur in the western region. Waste coal production is projected to increase slightly under the proposed rule due to the operation under both options of less than 1 GW of coal steam capacity that is projected to retire under the base case.

Table 3-15. Coal Production for the Electric Power Sector, 2020

	Coal Production (MM Tons)					Percent Change from Base Case			
	Base Case	Option 1		Option 2		Option 1		Option 2	
		Reg.	State	Reg.	State	Reg.	State	Reg.	State
Appalachia	140	87	91	n/a	n/a	-37%	-35%	n/a	n/a
Interior	249	231	222	n/a	n/a	-7%	-11%	n/a	n/a
West	446	308	292	n/a	n/a	-31%	-34%	n/a	n/a
Waste Coal	9	10	10	n/a	n/a	8%	5%	n/a	n/a
Imports	0	0	0	n/a	n/a			n/a	n/a
Total	844	636	616	n/a	n/a	-25%	-27%	n/a	n/a

Source: Integrated Planning Model run by EPA, 2014

Power sector natural gas use is projected to increase between 12% and 14% in 2020 under Option 1 and between 10% and 12% under Option 2. In later years, gas use declines under both options. These trends are consistent with the change in generation mix described above in Section 3.7.4.

Table 3-16. Power Sector Gas Use

	Power Sector Gas Use (TCF)			Percent Change in Power Sector Gas Use		
	2020	2025	2030	2020	2025	2030
Base Case	8.35	8.88	9.89			
Option 1 Regional	9.32	9.31	9.37	11.7%	4.8%	-5.3%
Option 1 State	9.54	9.52	9.61	14.3%	7.2%	-2.9%
Option 2 Regional	9.20	9.34	n/a	10.2%	5.1%	n/a
Option 2 State	9.35	9.52	n/a	12.0%	7.2%	n/a

Source: Integrated Planning Model run by EPA, 2014

3.7.8 *Projected Fuel Price Impacts*

The impacts of the proposed rule on coal and natural gas prices before shipment are shown below in Table 3-17, Table 3-18, Table 3-19, and Table 3-20, and are attributable to the policy-induced changes in overall power sector demand for each fuel.

Coal demand decreases over the 2020-2030 time horizon, resulting in a decrease in the price of coal delivered to the electric power sector. In 2020, the increase in natural gas demand results in an increase in the price of gas delivered to the electric power sector. In 2030, gas demand and price decrease below the base case projections, due to the cumulative impact of national demand-side energy efficiency savings and the consequent reduced overall electricity demand.

IPM modeling of natural gas prices uses both short- and long-term price signals to balance supply and demand for the fuel across the modeled time horizon. As such, it should be understood that the pattern of IPM natural gas price projections over time is not a forecast of natural gas prices incurred by end-use consumers at any particular point in time. The natural gas market in the United States has historically experienced some degree of price volatility from year to year, between seasons within a year, and during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). These short-term price signals are fundamental for allowing the market to successfully align immediate supply and demand needs. However, end-use consumers are typically shielded from experiencing these rapid fluctuations in natural gas prices by retail rate regulation and by hedging through longer-term fuel supply contracts by the power sector. IPM assumes these longer-term price arrangements take place “outside of the model” and on top of the “real-time” shorter-term price variation necessary to align supply and demand. Therefore, the model’s natural gas price projections should not be mistaken for traditionally experienced consumer price impacts related to natural gas, but a reflection of expected average price changes over the period of time represented by the modeling horizon.

Table 3-17. Projected Average Minemouth and Delivered Coal Prices (2011$/MMBtu)

	Minemouth			Delivered - Electric Power Sector		
	2020	2025	2030	2020	2025	2030
Base Case	1.73	1.88	2.06	2.62	2.80	2.98
Option 1 Regional	1.46	1.57	1.72	2.19	2.29	2.44
Option 1 State	1.45	1.56	1.70	2.18	2.30	2.44
Option 2 Regional	1.49	1.62	n/a	2.25	2.40	n/a
Option 2 State	1.49	1.62	n/a	2.26	2.41	n/a

Source: Integrated Planning Model run by EPA, 2014

Table 3-18. Projected Average Minemouth and Delivered Coal Prices: Percent Change from Base Case Projections

	Minemouth			Delivered - Electric Power Sector		
	2020	2025	2030	2020	2025	2030
Option 1 Regional	-15.5%	-16.6%	-16.4%	-16.3%	-18.3%	-18.1%
Option 1 State	-16.1%	-17.0%	-17.6%	-16.5%	-17.9%	-18.2%
Option 2 Regional	-14.1%	-14.1%	n/a	-13.8%	-14.4%	n/a
Option 2 State	-14.0%	-14.1%	n/a	-13.6%	-14.1%	n/a

Source: Integrated Planning Model run by EPA, 2014

Table 3-19. Projected Average Henry Hub (spot) and Delivered Natural Gas Prices (2011$/MMBtu)

	Henry Hub			Delivered - Electric Power Sector		
	2020	2025	2030	2020	2025	2030
Base Case	4.98	5.68	6.00	5.36	6.11	6.39
Option 1 Regional	5.50	5.60	6.02	5.86	5.91	6.33
Option 1 State	5.61	5.57	6.07	5.98	5.90	6.39
Option 2 Regional	5.40	5.79	n/a	5.76	6.13	n/a
Option 2 State	5.43	5.80	n/a	5.80	6.16	n/a

Source: Integrated Planning Model run by EPA, 2014

Table 3-20. Average Henry Hub (spot) and Delivered Natural Gas Prices: Percent Change from Base Case Projections

	Henry Hub			Delivered - Electric Power Sector		
	2020	2025	2030	2020	2025	2030
Option 1 Regional	10.4%	-1.5%	0.4%	9.3%	-3.3%	-0.9%
Option 1 State	12.5%	-2.0%	1.2%	11.5%	-3.5%	0.0%
Option 2 Regional	8.5%	2.0%	n/a	7.5%	0.2%	n/a
Option 2 State	9.0%	2.1%	n/a	8.1%	0.8%	n/a

Source: Integrated Planning Model run by EPA, 2014

3.7.9 Projected Retail Electricity Prices

EPA's analysis projects an increase in the national average (contiguous U.S.) retail electricity price between 5.9% and 6.5% in 2020 and between 2.7% and 3.1% by 2030 under the proposed Option 1, compared to the modeled base case price estimate in those years. Under Option 2, on average, EPA projects an average retail price increase ranging from 23.6% to 4.0% in 2020, and from 2.4% to 2.7% in 2025.

Retail electricity prices embody generation, transmission, distribution, taxes, and utility demand-side EE program costs. IPM modeling projects changes in regional wholesale power prices and capacity payments related to imposition of the represented policy that are combined with EIA regional transmission and distribution costs to calculate changes to regional retail prices. As described in Section 3.6.2, the utility funding for demand-side energy efficiency programs (to cover program costs) is typically collected through a standard per kWh surcharge to the ratepayer and the regional retail price impacts assume that first-year costs of these policies are recovered by utilities in retail rates. There are many factors influencing the estimated retail electricity price impacts, namely projected changes in generation mix, fuel prices, and development of new generating capacity. These projected changes vary regionally under each compliance scenario in response to the goals under the two options, and they also vary depending upon retail electricity market structure (e.g., cost-of-service vs. competitive).

Table 3-21. 2020 Projected Contiguous U.S. and Regional Retail Electricity Prices (cents/kWh)

	2020 Projected Retail Price (cents/kWh)					Percent Change from Base Case			
	Base Case	Option 1 Regional	Option 1 State	Option 2 Regional	Option 2 State	Option 1 Regional	Option 1 State	Option 2 Regional	Option 2 State
ERCT	9.9	10.6	10.8	10.4	10.5	7.4%	9.9%	5.3%	6.0%
FRCC	10.6	11.3	11.6	11.2	11.4	6.5%	8.7%	5.2%	7.1%
MROE	10.4	10.9	11.0	10.8	10.9	4.7%	5.8%	3.4%	4.2%
MROW	9.2	9.8	9.8	9.6	9.6	6.4%	7.0%	4.6%	4.9%
NEWE	13.8	15.2	15.4	14.5	14.8	10.1%	11.4%	5.1%	6.9%
NYCW	18.0	19.7	19.8	18.8	18.9	9.5%	10.0%	4.6%	5.0%
NYLI	14.7	16.1	16.1	15.3	15.3	9.3%	9.5%	3.7%	4.2%
NYUP	12.7	14.0	14.0	13.4	13.3	9.9%	9.8%	4.8%	4.5%
RFCE	12.2	13.3	13.2	12.6	12.8	8.6%	7.7%	3.2%	4.6%
RFCM	10.7	11.2	11.3	11.1	11.1	5.1%	6.0%	3.6%	3.9%
RFCW	10.1	10.7	10.8	10.4	10.3	6.1%	6.3%	2.5%	2.2%
SRDA	9.0	9.4	9.4	9.3	9.2	4.1%	4.5%	3.0%	2.8%
SRGW	9.3	9.7	9.7	9.5	9.5	4.9%	4.7%	2.1%	1.7%
SRSE	10.4	10.7	10.7	10.6	10.6	2.8%	3.4%	2.2%	2.2%
SRCE	8.2	8.4	8.4	8.3	8.4	1.5%	1.7%	1.3%	1.6%
SRVC	10.7	10.9	10.9	10.8	10.8	2.4%	2.2%	1.6%	1.5%
SPNO	10.6	11.7	10.7	11.4	10.7	9.9%	0.6%	7.5%	1.1%
SPSO	8.3	9.0	9.3	8.8	9.0	8.3%	11.7%	5.3%	7.7%
AZNM	10.5	11.1	11.3	10.9	11.1	5.3%	7.4%	3.9%	5.6%
CAMX	14.3	15.2	15.2	14.9	14.9	6.3%	6.4%	4.7%	4.5%
NWPP	7.3	7.7	7.8	7.6	7.6	6.1%	6.7%	4.5%	4.5%
RMPA	8.9	9.5	9.9	9.4	9.6	6.3%	10.4%	5.0%	6.9%
Contiguous U.S.	10.4	11.1	11.1	10.8	10.9	5.9%	6.5%	3.6%	4.0%

Table 3-22. 2025 Projected Contiguous U.S. and Regional Retail Electricity Prices (cents/kWh)

	2025 Projected Retail Price (cents/kWh)					Percent Change from Base Case			
	Base Case	Option 1 Regional	Option 1 State	Option 2 Regional	Option 2 State	Option 1 Regional	Option 1 State	Option 2 Regional	Option 2 State
ERCT	11.2	11.5	11.4	11.6	11.6	2.9%	1.8%	3.3%	3.7%
FRCC	10.9	11.4	11.5	11.3	11.5	4.5%	5.4%	4.1%	5.4%
MROE	10.5	10.9	11.0	10.8	10.9	4.0%	4.2%	2.5%	4.0%
MROW	9.2	9.8	9.8	9.6	9.6	5.8%	5.7%	4.3%	4.4%
NEWE	14.2	14.4	14.5	14.3	14.5	1.4%	1.9%	0.2%	1.6%
NYCW	18.8	19.1	19.1	18.9	18.9	1.5%	1.3%	0.5%	0.4%
NYLI	15.6	15.5	15.4	15.4	15.3	-0.4%	-1.4%	-1.4%	-1.5%
NYUP	13.2	13.3	13.2	13.2	13.1	0.2%	-0.4%	-0.3%	-0.8%
RFCE	12.6	12.7	12.9	13.0	13.0	0.4%	2.2%	3.0%	3.1%
RFCM	10.7	11.2	11.2	11.1	11.1	4.0%	4.5%	3.1%	3.6%
RFCW	10.9	10.9	11.0	10.9	11.0	-0.4%	0.0%	-0.1%	0.3%
SRDA	9.3	9.7	9.7	9.7	9.7	4.1%	3.7%	3.9%	3.6%
SRGW	10.1	10.1	10.1	10.1	10.1	-0.1%	-0.1%	-0.1%	-0.1%
SRSE	10.3	10.7	10.7	10.6	10.7	3.5%	3.8%	2.8%	2.9%
SRCE	8.2	8.5	8.5	8.4	8.4	3.1%	3.2%	2.2%	2.2%
SRVC	10.6	10.9	10.8	10.8	10.8	3.0%	2.5%	2.4%	2.0%
SPNO	10.3	11.8	10.8	11.3	10.7	14.1%	4.5%	8.7%	3.0%
SPSO	8.8	9.5	9.7	9.4	9.5	7.4%	9.4%	6.0%	7.7%
AZNM	10.8	11.2	11.3	11.0	11.2	3.9%	5.0%	2.4%	4.0%
CAMX	13.9	14.4	14.3	14.3	14.3	3.2%	2.9%	2.9%	2.9%
NWPP	7.4	7.8	7.7	7.6	7.6	5.0%	4.6%	3.4%	3.3%
RMPA	9.4	9.6	10.0	9.6	9.8	2.3%	6.4%	2.7%	4.8%
Contiguous U.S.	10.8	11.1	11.1	11.0	11.1	2.7%	2.9%	2.4%	2.7%

Table 3-23. 2030 Projected Contiguous U.S. and Regional Retail Electricity Prices (cents/kWh)

	2030 Projected Retail Price (cents/kWh)					Percent Change from Base Case			
	Base Case	Option 1 Regional	Option 1 State	Option 2 Regional	Option 2 State	Option 1 Regional	Option 1 State	Option 2 Regional	Option 2 State
ERCT	11.6	12.0	12.0	n/a	n/a	3.6%	3.9%	n/a	n/a
FRCC	10.9	11.5	11.5	n/a	n/a	4.7%	5.6%	n/a	n/a
MROE	10.5	10.9	11.1	n/a	n/a	4.0%	5.9%	n/a	n/a
MROW	9.4	9.8	9.8	n/a	n/a	4.3%	4.3%	n/a	n/a
NEWE	15.1	15.1	15.3	n/a	n/a	-0.1%	1.0%	n/a	n/a
NYCW	19.9	20.1	20.1	n/a	n/a	1.0%	0.8%	n/a	n/a
NYLI	16.9	16.5	16.3	n/a	n/a	-2.3%	-3.3%	n/a	n/a
NYUP	14.2	14.2	14.2	n/a	n/a	0.0%	-0.4%	n/a	n/a
RFCE	12.4	12.8	12.9	n/a	n/a	3.4%	4.2%	n/a	n/a
RFCM	10.8	11.2	11.2	n/a	n/a	3.8%	4.5%	n/a	n/a
RFCW	11.2	11.3	11.3	n/a	n/a	0.4%	0.6%	n/a	n/a
SRDA	9.5	9.9	9.9	n/a	n/a	4.6%	4.5%	n/a	n/a
SRGW	10.4	10.3	10.2	n/a	n/a	-1.2%	-1.6%	n/a	n/a
SRSE	10.4	10.7	10.8	n/a	n/a	3.2%	4.0%	n/a	n/a
SRCE	8.1	8.4	8.4	n/a	n/a	2.6%	2.7%	n/a	n/a
SRVC	10.4	10.7	10.6	n/a	n/a	3.0%	2.5%	n/a	n/a
SPNO	10.2	11.5	10.5	n/a	n/a	12.7%	3.1%	n/a	n/a
SPSO	9.1	9.7	9.9	n/a	n/a	7.2%	9.2%	n/a	n/a
AZNM	11.5	11.4	11.7	n/a	n/a	-0.2%	2.1%	n/a	n/a
CAMX	14.1	14.7	14.7	n/a	n/a	4.2%	3.9%	n/a	n/a
NWPP	7.4	7.7	7.7	n/a	n/a	2.8%	2.8%	n/a	n/a
RMPA	9.9	9.9	10.3	n/a	n/a	0.7%	4.7%	n/a	n/a
Contiguous U.S.	10.9	11.2	11.3	n/a	n/a	2.7%	3.1%	n/a	n/a

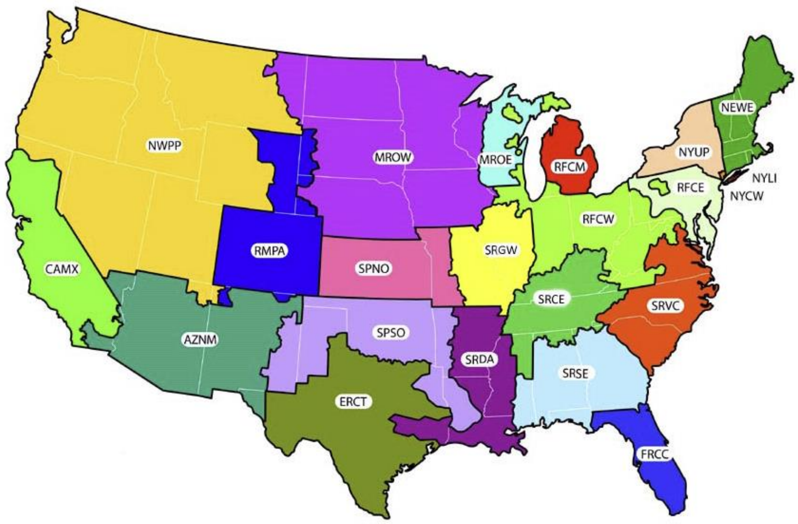

Figure 3-5. Electricity Market Module Regions

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

3.7.10 Projected Electricity Bill Impacts

The electricity price changes addressed in section 3.7.9 combine with the significant reductions in electricity demand applied in the illustrative scenarios to affect average electricity bills. The estimated changes to average bills are summarized in Table 3-24. Under Option 1, EPA estimates an average bill increase of 2.7% to 3.2% in 2020 and an average bill decrease of 8.4% to 8.7% in 2030. Under Option 2, EPA estimates an average bill increase of 1.1% to 1.4% in 2020 and an average bill decrease of 3.2% to 3.5% in 2025. These reduced electricity bills reflect the combined effects of changes in both average retail rates (driven by the effects of all four building blocks) and lower electricity demand (driven by the fourth building block, demand-side energy efficiency).

Table 3-24. Projected Changes in Average Electricity Bills

	2020	2025	2030
Option 1 Regional	2.7%	-5.4%	-8.7%
Option 1 State	3.2%	-5.3%	-8.4%
Option 2 Regional	1.1%	-3.5%	n/a
Option 2 State	1.4%	-3.2%	n/a

3.8 Projected Primary PM Emissions from Power Plants

IPM is not configured to endogenously model primary PM emissions from power plants. These emissions are calculated as a function of IPM outputs, emission factors and control configuration. IPM-projected fuel use (heat input) is multiplied by PM emission factors (based in part on the presence of PM-relevant pollution control devices) to determine PM emissions. Primary PM emissions are calculated by adding the filterable PM and condensable PM emissions.

Filterable PM emissions for each unit are based on historical information regarding existing emissions controls and types of fuel burned and ash content of the fuel burned, as well as the projected emission controls (e.g., scrubbers and fabric filters).

Condensable PM emissions are based on plant type, sulfur content of the fuel, and SO_2/HCl and PM control configurations. Although EPA's analysis is based on the best available emission factors, these emission factors do not account for the potential changes in condensable PM emissions due to the installation and operation of SCRs. The formation of additional condensable PM (in the form of SO_3 and H_2SO_4) in units with SCRs depends on a number of factors, including coal sulfur content, combustion conditions and characteristics of the catalyst used in the SCR, and is likely to vary widely from unit to unit. SCRs are generally designed and operated to minimize increases in condensable PM. This limitation means that IPM post-processing is potentially underestimating condensable PM emissions for units with SCRs. In contrast, it is possible that IPM post-processing overestimates condensable PM emissions in a case where the unit is combusting a low-sulfur coal in the presence of a scrubber.

EPA applied this methodology to develop primary PM emission projections for 2025 in the base case, and for Option 1 State and Option 2 Regional. Using these results, EPA then estimated primary PM emissions for the remainder of the base case and policy scenarios over the 2020-2030 time horizon using simplified emissions factors. These factors were developed for the eastern and western regions (excluding California) using EPA's emissions and fuel use projections for fossil plus biomass. Separate factors were developed for base case and policy case scenarios. These factors were applied to the projected fuel use from fossil and biomass plant types. While this methodology provides a reasonable estimate, EPA notes that applying the methodology discussed above would likely yield different results. Nevertheless, EPA has determined that this estimation is sufficient for the purpose of estimating benefits on a large regional level.

For a more complete description of the methodologies used to post-process PM emissions from IPM, see "IPM ORL File Generation Methodology" (March, 2011), available in the docket.

3.9 Limitations of Analysis

EPA's modeling is based on expert judgment of various input assumptions for variables whose outcomes are in fact uncertain. As a general matter, the Agency reviews the best available information from engineering studies of air pollution controls, the ability to improve operating efficiency, and new capacity construction costs to support a reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory actions.

The costs presented in this RIA include both the IPM-projected annualized estimates of private compliance costs as well as the estimated costs incurred by utilities and ratepayers to achieve demand-side energy efficiency improvements. The IPM-projected annualized estimates of private compliance costs provided in this analysis are meant to show the increase in production (generating) costs to the power sector in response to the final rule. To estimate these annualized costs, EPA uses a conventional and widely-accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital.[60]

The demand-side energy efficiency costs are developed based on a review of energy efficiency data and studies, and expert judgment. EPA recognizes that significant variation exists in these analyses reflecting data and methodological limitations. The method used for estimating the demand-side energy efficiency costs is discussed in more detail in the Greenhouse Gas Abatement Measures TSD. The TSD also discusses the economic literature of energy efficiency costs and related considerations, energy savings potential studies, and discusses the associated

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[60] See Chapter 8 of EPA's Base Case using IPM (v5.13) documentation, available at: http://www.epa.gov/powersectormodeling/BaseCasev513.html.

uncertainties. The evaluation, measurement and verification (EM&V) of demand-side energy efficiency is addressed in the State Plan Considerations TSD.

The base case electricity demand in IPM v.5.13 is calibrated to reference case demand in AEO 2013. AEO 2013 demand reflects, to some degree, a continuation of the impacts of state demand-side energy efficiency policies but does not explicitly represent many of the existing state policies in this area (e.g., energy efficiency resource standards). To some degree the implicit representation of state policies in the EPA's base case alters the impacts assessment, but the direction of change is not known with certainty. This issue is discussed in more detail in the Greenhouse Gas Abatement Measures TSD.

Cost estimates for the proposed rule are based on rigorous power sector modeling using ICF's Integrated Planning Model.[61] IPM assumes "perfect foresight" of market conditions over the time horizon modeled; to the extent that utilities and/or energy regulators misjudge future conditions affecting the economics of pollution control, costs may be understated as well. Furthermore, IPM does not represent electricity markets in Alaska, Hawaii, and U.S. territories outside the contiguous U.S. and therefore the costs (and benefits) that may be expected from the proposed rule in this states and territories are not accounted for in the compliance cost modeling.

3.10 Significant Energy Impacts

The proposed rule (Option 1) would have a significant impact according to E.O. 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use. Under the provisions of this rule, EPA projects that approximately 46 to 49 GW of additional coal-fired generation (about 19% of all coal-fired capacity and 4.6% of total generation capacity in 2020) may be removed from operation by 2020.

EPA also projects the average delivered coal price decreases by 16.3% to 16.5% with decreased production of 208 to 228 million tons (24.6% to 27.7% of US production) in 2020 and that electric power sector delivered natural gas prices will increase by about 9.3% to 11.5% with increased power sector consumption of between 979 to 1,194 billion cubic feet (BCF) in 2020.

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[61] Full documentation for IPM can be found at <http:// http://www.epa.gov/powersectormodeling>.

Average retail electricity prices are projected to increase in the contiguous U.S. by 5.9% to 6.5% in 2020.

3.11 Monitoring, Reporting, and Recordkeeping Costs

EPA projected monitoring, reporting and recordkeeping costs for both state entities and affected EGUs for the compliance years 2020, 2025 and 2030. In calculating the costs for state entities, EPA estimated personnel costs to oversee compliance, and review and report annually to EPA on program progress relative to meeting the state's reduction goal. To calculate the national costs, EPA estimated that 49 states and 1,228 facilities would be affected.

In calculating the cost for affected EGUs to comply, EPA assumed that the state plan would utilize a rate-based emission limit. The EPA estimated that the majority of the cost to EGUs would be in calculating net energy output. Since the majority of EGUs do have some energy usage meters or other equipment available to them, EPA believes a new system for calculating net energy output is not needed. However, an affected EGU will still need to be modify their equipment to comply with a rate-based limit as described in the emission guidelines. The EPA estimates that it would take 3 working months for a technician to retrofit any existing energy meters to meet the requirements set in the state plan. Additionally EPA believes that 1 hour will be needed for each EGU operator to read the rule and understand how the facility will comply with the rule. Also, after all modifications are made at a facility to measure net energy output, each EGUs Data Acquisition System (DAS) would need to be upgraded to supply the rate-based emissions value to either the state or EPA's Emissions Collection and Monitoring Plan System (ECMPS). Note the costs to develop net energy output monitoring and to upgrade each facility's DAS system are one-time costs incurred in 2020. Recordkeeping and reporting costs substantially decrease for the period 2021-2030. The projected costs for 2020, 2025, and 2030 are summarized below.

In calculating the cost for states to comply, EPA estimates that each state will rely on the equivalent of 2 full time staff to oversee program implementation, assess progress, develop possible contingency measures, state plan revisions and the subsequent public meetings if revisions are indeed needed, download data from the ECMPS for their annual reporting and develop their annual EPA report. Table 3-25 shows the annual respondent burden costs and costs of reporting and recordkeeping for 2020, 2025 and 2030.

Table 3-25. Years 2020, 2025 and 2030: Summary of Annual Respondent Burden and Cost of Reporting and Recordkeeping Requirements (2011$)

Nationwide Totals	Total Annual Labor Burden (Hours)	Total Annual Labor Costs	Total Annualized Capital Costs	Total Annual O&M Costs	Total Annualized Costs
Year 2020	900,048	$65,573,900	$0	$2,701,100	$68,275,000
Year 2025	217,280	$8,215,240	$0	$638,500	$8,853,740
Year 2030	217,280	$8,215,240	$0	$638,500	$8,853,740

The annual costs of this proposal Option1 and regulatory alternative Option 2 including monitoring reporting and recordkeeping costs are shown in Table 3-26 below.

Table 3-26. Annualized Compliance Costs Including Monitoring, Reporting and Recordkeeping Costs Requirements (billions of 2011$)

	2020	2025	2030
Option 1 Regional	5.5	4.6	7.3
Option 1 State	7.5	5.5	8.8
Option 2 Regional	4.3	4.5	n/a
Option 2 State	5.5	5.5	n/a

Source: Integrated Planning Model run by EPA, 2014 and GHG Abatement Measures TSD. Monitoring, reporting and recordkeeping costs calculated outside IPM.

3.12 Social Costs

As discussed in the EPA Guidelines for Preparing Economic Analyses, social costs are the total economic burden of a regulatory action. This burden is the sum of all opportunity costs incurred due to the regulatory action, where an opportunity cost is the value lost to society of any goods and services that will not be produced and consumed as a result of reallocating some resources towards pollution mitigation. Estimates of social costs may be compared to the social benefits expected as a result of a regulation to assess its net impact on society. The social costs of a regulatory action will not necessarily be equivalent to the expenditures associated with compliance. Nonetheless, here we use compliance costs as a proxy for social costs. This section provides a qualitative discussion of the relationship between social costs and compliance cost estimates presented in this chapter.

For the illustrative compliance scenarios cost estimates presented in this chapter are the sum of expenditures on end-use energy efficiency programs and the change in expenditures required by the electricity sector to comply with the proposed guidelines. These two components are estimated separately. The expenditures required to achieve the assumed demand reductions through end-use energy efficiency programs are estimated using historical data and expert judgment. The change in the expenditures required by the electricity sector to meet demand and maintain compliance are estimated by IPM and reflect both the reduction in electricity production costs due to the reduction in demand caused by the end-use energy efficiency programs and the increase in electricity production costs required to achieve the additional emission reductions necessary to comply with the state goals.[62]

As described in section 3.6.1, the illustrative scenarios generally assume that, in achieving their goals, states adopt energy efficiency programs which lead to net demand reductions in each year equivalent to those applied in the calculation of their respective goals. The estimated expenditures required to achieve those net demand reductions through end-use energy efficiency programs are presented in this chapter and detailed in the GHG Abatement Measures TSD chapter on end-use energy efficiency. The social cost of achieving these energy savings comes in the form of increased expenditures on technologies and/or services that are required to lower end-user's electricity consumption beyond the business as usual. Under the assumption of complete and well-functioning markets the expenditures required to reduce electricity consumption on the margin will represent society's opportunity cost of the resources required to produce the energy savings.

The social cost of achieving these net electricity demand reductions may differ from the expenditures associated with the end-use energy efficiency programs. For example, some participants in end-use energy efficiency programs might have chosen to adopt the energy

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[62] As described in section 3.5, IPM provides the least-cost solution to attaining the constraints representing the regulation required used to achieve the state goals but for the component of the state goals that is achieved by end use energy efficiency programs.

efficiency improvements even in the absence of the program.[63] Therefore the expenditures, except for any program administration expenditures, associated with those demand reductions are not part of the program's social costs, as they would have accrued even in its absence.[64] The compliance cost estimates for the illustrative scenarios includes this limited share of the program costs that is expended on end-users who would have reduced their demand in the absence of the program. Thus, with respect to this particular issue, the social cost of the illustrative scenarios would be less than the estimated compliance cost reported in Table 3-8 to a limited degree. If the program expenditures that do not lead to additional demand reductions are paid for by electricity rate or tax payer funded programs then that portion of program expenditures represents a transfer among electricity consumers and has no net welfare gain or loss to society as a whole.

Due to the flexibility held by states in implementing their compliance with the proposed standards these energy efficiency expenditures may be borne by end-users through direct participant expenditures or electricity rate increases or by producers through reductions in their profits. While the allocation of these expenditures between consumers and producers is important for understanding the distributional impact of potential compliance strategies, it does not necessarily affect the opportunity cost required for the production of the energy savings from a social perspective. However, specific design elements of demand-side or end-use energy efficiency programs included to address distributional outcomes may have an effect on the economic efficiency of the programs and therefore the social cost.

Another reason the expenditures associated with end-use energy efficiency programs may differ from social costs is due to differences in the services provided by more energy efficient technologies and services adopted under the program relative to the baseline. For example, if

[63] For example if a rebate program is offered for energy efficient appliances, some participants that claim the rebate may have purchased the more energy efficient appliances even without the rebate and so the rebate and investment made by these end-users is not a social cost of the program. However, the administrative cost of the rebate program is a social cost as it requires the reallocation of societal resources.

[64] The demand reductions assumed in the illustrative compliance scenarios only include those additional demand reductions motivated by the program costs. That is, the demand reductions assumed for the illustrative compliance scenarios already account for the potential that some program costs do not lead to additional energy efficiency investments by end-users. For more information see the GHG Abatement Measures TSD chapter on end-use energy efficiency.

under the program end-users adopted more energy efficient products which were associated with quality or service attributes deemed less desirable, then there would be an additional welfare loss that should be accounted for in social costs but is not necessarily captured in the measure of expenditures. However, there is an analogous (and more common) possibility that in some cases the quality of services, outside of the energy savings, provided by the more energy efficient products and practices are deemed more desirable by some end-users. For example, weatherization of buildings to reduced electricity demand associated with cooling will likely have a significant impact on natural gas use associated with heating. In either case these real welfare impacts are not fully captured by end-use energy efficiency expenditure estimates.

The fact that such quality and service differences may exist in reality but may not be reflected in the price difference between more and less energy efficient products is one potential hypothesis for the energy paradox. The energy paradox is the observation that end-users do not always purchase products that are more energy efficient when the additional cost is less than the reduction in the net present value of expected electricity expenditures achieved by those products.[65] Such circumstances are present in the analysis presented in this chapter, whereby in some regions the base case and illustrative scenarios suggest that cost of reducing demand through energy efficiency programs is less than the retail electricity price. In addition to heterogeneity in product services and consumer preferences, there are other explanations for the energy paradox, falling both within and outside the neoclassical rational expectations paradigm that is used in benefit/cost analysis. The end-use energy efficiency chapter of the GHG Abatement Measures TSD discusses the energy paradox in detail and provides additional hypothesis for why consumers may not make energy efficiency investments that ostensibly seem to be in their own interest. The TSD discussion also provides details on how the presence of additional market failures can lead to levels of energy efficiency investment that may be too low from society's perspective even if that is not the case for the end-user. In such cases there is the potential for properly designed energy efficiency programs to address the source of under-investment, such as principal-agent problems where there is a disconnect between those making

[65] An analogous situation is present when some EGUs have assumed to have the ability to make heat rate improvements at a capital cost that is less than the anticipated fuel expenditure savings.

the purchase decision regarding energy efficient investments and energy use and those that would receive the benefits associated with reduced energy use through lower electricity bills.

The other component of compliance cost reported in this chapter is the change in resource cost (i.e., expenditures) required by the electricity sector to fulfill the remaining demand while making additional CO_2 emissions intensity reductions necessary to comply with the state goals. Included in the estimate of these compliance costs, developed using IPM, are the cost savings associated with the reduction in required electricity generation due to the demand reductions from end-use energy efficiency programs and improvements in heat rate. By shifting the demand curve for electricity, energy efficiency programs reduce the production cost in the sector. The resource cost estimates from IPM therefore account for the increased cost of providing electricity at a lower average emissions rate net of the reduction in production costs due to lower demand from end-use energy efficiency programs.

Under the assumption that impacts outside the electricity market and markets providing inputs to the electricity sector do not meaningfully affect the prices in those markets, and the assumption of fixed electricity demand, then the social costs associated with the regulatory action would be equal to the resource costs measured by IPM (net of tax and subsidy payments and recovery of sunk costs). Under these assumptions the change in compliance cost will equal the reduction in producer[66] and consumer surplus[67] in the electricity sector from the pre-regulatory action market equilibrium. However, IPM forecasts production and price changes in fuel markets, which implies that there are changes in producer and consumer surplus in those markets, and therefore the resource cost estimate by IPM may differ from the social cost for this reason. For a theoretically consistent method for estimating partial-equilibrium changes in welfare where prices and outputs change in multiple markets see Chapter 9 of Just et al. (2004).

[66] Producer surplus is a welfare measure representing the amount gained by producers from selling output at a market price higher than the price they are willing to accept.

[67] Consumer surplus is a welfare measure representing the monetized value of the benefit consumers receive from consumption of purchased goods or services beyond their opportunity cost as defined by the market price.

3.13 References

Just, R.J., D.L. Hueth and A. Schmitz, (2004) *The Welfare Economics of Public Policy: A Practical Guide to Policy and Project Evaluation*, Edwin Elgar Press, Cheltenham UK.

US EPA (2010) EPA Guidelines for Preparing Economic Analyses, Chapters 8 and Appendix A. http://yosemite.epa.gov/ee/epa/eed.nsf/webpages/guidelines.html

APPENDIX 3A: ANALYSIS OF POTENTIAL UPSTREAM METHANE EMISSIONS CHANGES IN NATURAL GAS SYSTEMS AND COAL MINING

The purpose of this appendix is to describe the methodology for estimating upstream methane (CH_4) emissions related to natural gas systems and coal mining sectors that may result from the compliance approaches examined in the Regulatory Impact Analysis (RIA). The US Environmental Protection Agency (EPA) assessed whether the net change in upstream methane emissions from natural gas and coal production is likely to be positive or negative and also assessed the potential magnitude of these upstream changes relative to CO_2 emissions reductions anticipated at power plants from the compliance strategies examined in the RIA. In addition to estimating changes in upstream methane emissions, this assessment included estimating CO_2 from the flaring of methane, but did not examine other potential changes in other upstream greenhouse gas emissions changes from natural gas systems and coal mining sectors.

The methodologies used to project upstream emissions were previously developed for the purpose of the Sixth U.S. Climate Action Report, and were subject to peer review and public review as part of the publication of that report. In section 3A.1, the overall approach is described in brief. In section 3A.2, results are presented. In section 3A.3, detailed methodologies are presented for how CH_4 and flaring-related CO_2 projections were calculated for coal mining and natural gas systems. Finally, section 3A.4 contains a bibliography of cited resources.

3A.1 General Approach

3A.1.1 Analytical Scope

Upstream CH_4 and flaring-related CO_2 emissions associated with coal mining and natural gas systems were estimated for 2020 through 2030 using methodologies developed for the 2014 U.S. Climate Action Report (U.S. Department of State 2014). The base year for the projections is 2011, as reported in the 2013 U.S. GHG Inventory (EPA 2013a). The projection methodologies use activity driver data outputs such as coal and natural gas production from the base case and policy scenarios generated by the Integrated Planning Model (IPM), which was used in the RIA to model illustrative compliance strategies. The projection methodologies use similar activity data and emissions factors as are used in the U.S. Greenhouse Gas (GHG) Inventory. The projection methodologies estimate reductions associated with both voluntary and regulatory programs affecting upstream CH_4-related emissions. In the case of the voluntary programs, the rate of reductions is based on the historical average decrease from these programs over recent years. In the case of regulatory reductions, the reductions are based on the reduction rates estimated in the RIAs of relevant regulations. The methodologies to estimate upstream emissions were subject to expert peer review and public review in the context of the Sixth U.S. Climate Action Report. For more information on the review, or for the detailed methodologies used for non-CO_2 source projections in that report, including CH_4-related emissions from coal production and natural gas systems, see “Methodologies for U.S. Greenhouse Gas Emissions Projections: Non-CO_2 and Non-Energy CO_2 Sources” (EPA, 2013b). Uncertainties and limitations are discussed, including a side case which incorporates additional geographic information for estimating CH_4 from coal mining.

The term “upstream emissions” in this memo refers to vented, fugitive and flared emissions associated with fuel production, processing, transmission, storage, and distribution of fuels prior to fuel combustion in electricity plants. For this analysis, the EPA focused on upstream CH_4 from the natural gas systems and coal mining sectors. In addition, the analysis included CO_2 resulting from flaring in natural gas production. This analysis does not assess other upstream GHG emissions changes, such as CO_2 emissions from the combustion of fuel used in natural gas and coal production activities or other non-combustion CO_2 emissions from natural gas systems, such as vented CO_2 and CO_2 emitted from acid-gas removal processes.

Also, the EPA assessed potential upstream methane emissions from natural gas systems and coal mining sectors within the domestic U.S., but did not examine emissions from potential changes in upstream emissions generated by changes in natural gas and coal production, processing, and transportation activities outside of the US.[68] Last, the EPA did not assess potential changes in other upstream non-GHG emissions, such as nitrogen oxides, volatile

[68] While the analysis does not estimate methane emissions changes outside of the United States, activity factors include imports and exports of natural gas to help estimate domestic methane emissions related to trade of natural gas, such as emissions from LNG terminals in the US or from pipelines transporting imported natural gas within the US (or transporting natural gas within the US while en route for export).

organic compounds, and particulate matter. Table 3A-1 presents estimates of the upstream emissions discussed in this analyses for 2011, based on the 2013 U.S. GHG Inventory.

EPA defined the boundaries of this assessment in order to provide targeted insights into the potential net change in CH_4 emissions from natural gas systems and coal production activities specifically. CO_2 emissions from flared methane are included because regulatory and voluntary programs influence the rate of CH_4 flaring over time and the CO_2 remaining after flaring is a CH_4 -related GHG. Because of the multiple compliance strategies adopted in the illustrative compliance scenarios, a more comprehensive assessment of upstream GHG emissions would require examination of the broader power sector and related input markets and their potential changes in response to the rule. This analysis would be complex and likely subject to data limitations and substantial uncertainties. Rather, EPA chose to limit the scope of this upstream analysis to evaluate the potential for changes in GHG emissions that may be of significant scale relative to the impacts of the rule and for which EPA had previously-reviewed projection techniques, which are presented in detail below.

3A.1.2 Coal Mining Source Description

Within coal mining, this analysis covers fugitive CH_4 emissions from coal mining (including pre-mining drainage) and post-mining activities (i.e., coal handling), including both underground and surface mining. Emissions from abandoned mines are not included. Energy-related CO_2 emissions, such as emissions from mining equipment and vehicles transporting coal are not included. CH_4, which is contained within coal seams and the surrounding rock strata, is released into the atmosphere when mining operations reduce the pressure above and/or surrounding the coal bed. The quantity of CH_4 emitted from these operations is a function of two primary factors: coal rank and coal depth. Coal rank is a measure of the carbon content of the coal, with higher coal ranks corresponding to higher carbon content and generally higher CH_4 content. Pressure increases with depth and prevents CH_4 from migrating to the surface; as a result, underground mining operations typically emit more CH_4 than surface mining. In addition to emissions from underground and surface mines, post-mining processing of coal and abandoned mines also release CH_4. Post-mining emissions refer to CH_4 retained in the coal that is released during processing, storage, and transport of the coal.

3A.1.3 Natural Gas Systems Source Description

Within natural gas systems, this analysis covers vented and fugitive CH_4 emissions from the production, processing, transmission and storage, and distribution segments of the natural gas system. It also includes CO_2 from flaring of natural gas. Not included are vented and fugitive CO_2 emissions from natural gas systems, such as vented CO_2 emissions removed during natural gas processing, or energy-related CO_2 such as emissions from stationary or mobile combustion. The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. CH_4 and non-combustion[69] CO_2 emissions from natural gas systems are generally process-related, with normal operations, routine maintenance, and system upsets being the primary contributors. There are four primary stages of the natural gas system which are briefly described below.

Production: In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities (e.g., dehydrators, separators). Major emissions source categories within the production stage include pneumatic devices, gas wells with liquids unloading, and gas well completions and re-completions (i.e., workovers) with hydraulic fracturing (EPA 2013). Flaring emissions account for the majority of the non-combustion CO_2 emissions within the production stage.

Processing: In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline-quality" gas, which is then injected into the transmission system. Fugitive CH_4 emissions from compressors, including compressor seals, are the primary emissions source from this stage. In the U.S. GHG Inventory, the majority of non-combustion CO_2 emissions in the processing stage come from acid gas removal units, which are designed to remove CO_2 from natural gas.

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[69] In this document, consistent with IPCC accounting terminology, the term "combustion emissions" refers to the emissions associated with the combustion of fuel for useful heat and work, while "non-combustion emissions" refers to emissions resulting from other activities, including flaring and CO_2 removed from raw natural gas.

Transmission and Storage: Natural gas transmission involves high-pressure, large-diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large-volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the U.S. transmission system. Fugitive CH_4 emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and non-combusted engine exhaust are also sources of CH_4 emissions from transmission facilities. Natural gas is also injected and stored in underground formations, or liquefied and stored in above-ground tanks, during periods of lower demand (e.g., summer), and withdrawn, processed, and distributed during periods of higher demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. Emissions from LNG import terminals are included within the transportation and storage stage.

Distribution: Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure, and then distribute the gas through primarily underground mains and service lines to individual end users.

Table 3A-1. Base Year Upstream Methane-Related Emissions in the U.S. GHG Inventory

Emissions Source	2011 Emissions ($TgCO_2e$)
CH_4 from Coal Mining	**75.2**
Underground Mining and Post-Mining	57.4
Surface Mining and Post-Mining	18.0
CH_4 from Natural Gas Systems	**172.3**
Production	63.6
Processing	23.3
Transmission and Storage	52.1
Distribution	33.2
CO_2 from flaring of natural gas	**10.3**

Source: 2013 U.S. GHG Inventory (EPA, 2013). A Global Warming Potential of 25 was used to convert methane emissions to CO_2e.

It is important to note that in Table 3A-1, CO_2-equivalent methane emissions are presented using the Fourth Assessment Report Global Warming Potential (GWP) of 25, whereas CO_2-equivalent methane emissions in the 1990-2011 U.S. GHG Inventory (EPA 2013) are presented using the Second Assessment Report GWP of 21. EPA plans to use 25 as the methane GWP starting with the 1990-2013 U.S. GHG Inventory, to be published in April 2015.

3A.1.4 Compliance Approaches Examined

States will ultimately determine optimal approaches to comply with the goals established in this regulatory action. Each of these goal approaches use the four building blocks described in the Executive Summary of the RIA at different levels of stringency. Option 1 involves higher deployment of the four building blocks but allows a longer timeframe to comply (2030) whereas Option 2 has a lower deployment over a shorter timeframe (2025). The RIA depicts illustrative state compliance scenarios for the goals set for Options 1 and 2, inclusive of regional and state compliance approaches for each option.

3A.1.5 Activity Drivers

IPM-based activity driver projections from base case and illustrative compliance scenarios underlie the estimates of upstream CH_4 emissions. These activity drivers include domestic coal and natural gas production, imports and exports, and natural gas consumption. For a sensitivity analysis described later, regional coal production is used for the Appalachian, Interior, and Western regions. The following Tables 3A-2 to 3A-5 summarize the IPM-based activity driver results from the baseline, Option 1 Regional and State scenarios, and Option 2 Regional and State scenarios.[70]

Under Option 1, the state and regional compliance scenarios result in 24 percent and 22 percent reductions in coal production in 2020, respectively, relative to base case coal production. Natural gas production in 2020 increases by 4 percent as a result of the Option 1 State compliance scenario, and increases by 3 percent in the Option 1 Regional compliance scenario relative to the base case.

Under Option 2, the state and regional compliance scenarios result in 19 percent and 17 percent reductions in coal production in 2020, respectively, relative to base case coal production. Natural gas production in 2020 increases by 3 percent as a result of either the Option 2 state compliance scenario or the Option 2 Regional compliance scenario, relative to the base case.

[70] Uncertainties related to activity drivers are discussed in the uncertainties and limitations section.

Table 3A-2. Projected Coal Production Impacts, Option 1

	Coal Production (million short tons)			Coal Production Change from Base Case (million short tons)			Coal Production Percent Change from Base Case		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Base Case	921	952	951						
Option 1 State	695	682	682	-225	-270	-269	-24%	-28%	-28%
Option 1 Regional	716	698	702	-205	-254	-249	-22%	-27%	-26%

Table 3A-3. Projected Coal Production Impacts, Option 2

	Coal Production (million short tons)			Coal Production Change from Base Case (million short tons)			Coal Production Percent Change from Base Case		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Base Case	921	952	n/a						
Option 2 State	747	749	n/a	-174	-203	n/a	-19%	-21%	n/a
Option 2 Regional	763	764	n/a	-157	-187	n/a	-17%	-20%	n/a

Table 3A-4. Projected Natural Gas Production Impacts, Option 1

	Dry Gas Production (trillion cubic feet)			Dry Gas Production Change from Base Case (trillion cubic feet)			Dry Gas Production Percent Change from Base Case		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Base Case	26.6	29.3	31.9						
Option 1 State	27.7	29.8	31.7	+1.1	+0.6	-0.2	+4%	+2%	-1%
Option 1 Regional	27.5	29.7	31.5	+0.9	+0.4	-0.4	+3%	+1%	-1%

Table 3A-5. Projected Natural Gas Production Impacts, Option 2

	Dry Gas Production (trillion cubic feet)			Dry Gas Production Change from Base Case (trillion cubic feet)			Dry Gas Production Percent Change from Base Case		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Base Case	26.6	29.3	n/a						
Option 2 State	27.5	29.8	n/a	+0.9	+0.5	n/a	+3%	+2%	n/a
Option 2 Regional	27.4	29.7	n/a	+0.8	+0.4	n/a	+3%	+1%	n/a

3A.2 Results

This section presents results for the main analysis and sensitivity analysis. The detailed methods used to perform the analysis are presented in section 3A.3.

3A.2.1 Primary Results

Both Options 1 and 2, in either the state or regional compliance scenarios, result in total net reductions in upstream CH_4 emissions and CO_2 emissions (see Table 3A-6). Under

Option 1, the state compliance scenario results in net emissions reduction of 10.6 $TgCO_2e$ in 2020, while the regional compliance scenario results in 9.9 $TgCO_2e$ reduction. Under Option 2, the net emissions reduction is smaller: 7.7 and 7.4 $TgCO_2e$ in the state and regional compliance scenarios in 2020, respectively. These net emissions changes represent the sum of changes in CH_4 from coal mining, CH_4 from natural gas systems, and CO_2 from flaring in natural gas production.

Under the regional compliance scenario, Option 1 would result in decreases in CH_4 emissions from coal mining of 14.7 $TgCO_2e$ in 2020, 18.2 $TgCO_2e$ in 2025, and 17.7 $TgCO_2e$ in 2030. Under the same scenario, CH_4 from natural gas systems increases relative to the base case in 2020 (4.4 $TgCO_2e$) and 2025 (2.1 $TgCO_2e$) but decreases relative to the base case in 2030 (by 1.7 $TgCO_2e$). Following a similar pattern, CO_2 from flaring in natural gas production increases by 0.4 $TgCO_2e$ in 2020 and 0.3 $TgCO_2e$ in 2025 while decreasing by 0.3 $TgCO_2e$ in 2030. The total net change under the Option 1 regional compliance scenario is a reduction in emissions.

Under the regional compliance scenario, Option 2 would result in decreases in CH_4 emissions from coal mining of 11.3 $TgCO_2e$ in 2020 and 13.4 $TgCO_2e$ in 2025. CH_4 from natural gas systems increases relative to the base case in 2020 (3.6 $TgCO_2e$) and 2025 (1.8 $TgCO_2e$). CO_2 from flaring in natural gas production increases in 2020 and 2025. Like Option 1, the total net change under the Option 2 Regional compliance scenario is a reduction in emissions. The full results are listed in Table 3A-6.

Table 3A-6. Upstream Emissions Changes, Baseline to Compliance Scenarios

	Emissions ($TgCO_2e$)		
	2020	**2025**	**2030**
Option 1 State			
CH_4 from Coal Mining	-16.1	-19.3	-19.1
CH_4 from Natural Gas Systems	+5.1	+2.6	-1.0
CO_2 from NG flaring	+0.4	+0.2	-0.3
Total CH_4 + CO_2	**-10.6**	**-16.4**	**-20.5**
Option 1 Regional			
CH_4 from Coal Mining	-14.7	-18.2	-17.7
CH_4 from Natural Gas Systems	+4.4	+2.1	-1.7
CO_2 from NG flaring	+0.4	+0.1	-0.5
Total CH_4 + CO_2	**-9.9**	**-16.0**	**-19.8**
Option 2 State			
CH_4 from Coal Mining	-12.4	-14.5	n/a
CH_4 from Natural Gas Systems	+4.4	+2.4	n/a
CO_2 from NG flaring	+0.4	+0.3	n/a
Total CH_4 + CO_2	**-7.7**	**-11.8**	n/a
Option 2 Regional			
CH_4 from Coal Mining	-11.3	-13.4	n/a
CH_4 from Natural Gas Systems	+3.6	+1.8	n/a
CO_2 from NG flaring	+0.2	+0.1	n/a
Total CH_4 + CO_2	**-7.4**	**-11.4**	n/a

Note: A Global Warming Potential of 25 was used to convert methane emissions to CO_2e.

3A.2.2 Sensitivity Analysis: Side Case Incorporating More Coal Production Geographic Detail

A number of factors could potentially affect the changes in upstream emission as a result of the policy. Here, we present sensitivity analysis examining the possible effect of shifts in regional coal production that might result in a changing the relative share of production originating in underground mines and surface mines. This sensitivity analysis is presented because underground mining generally emits more CH_4 emissions per ton of coal production than surface mining. The compliance scenarios show generally larger reductions in coal production in the western region where more of the generally lower-emitting surface mining takes place. This analysis is characterized as a “sensitivity analysis” as the methods that were peer-reviewed as part of the EPA’s contribution to the Climate Action Report, which did not examine alternative coal production scenarios, did not incorporate this geographic component. After incorporating this effect, the net upstream CH_4 emissions reductions that may result from the compliance scenarios are approximately 1 to 2 $TgCO_2e$ lower than the results found in the main analysis (see Table 3A-7).

Table 3A-7. Upstream Emissions Changes, Baseline to Compliance Scenarios, Side Case Incorporating More Coal Production Geographic Detail

	Emissions ($TgCO_2e$)		
	2020	**2025**	**2030**
Option 1 State			
CH_4 from Coal Mining	-14.1	-17.4	-17.8
CH_4 from Natural Gas Systems	+5.1	+2.6	-1.0
CO_2 from NG flaring	+0.4	+0.2	-0.3
Total CH_4 + CO_2	**-8.6**	**-14.6**	**-19.2**
Option 1 Regional			
CH_4 from Coal Mining	-13.1	-16.5	-16.3
CH_4 from Natural Gas Systems	+4.4	+2.1	-1.7
CO_2 from NG flaring	+0.4	+0.1	-0.5
Total CH_4 + CO_2	**-8.3**	**-14.3**	**-18.5**
Option 2 State			
CH_4 from Coal Mining	-11.2	-13.2	n/a
CH_4 from Natural Gas Systems	+4.4	+2.4	n/a
CO_2 from NG flaring	+0.4	+0.3	n/a
Total CH_4 + CO_2	**-6.4**	**-10.4**	n/a
Option 2 Regional			
CH_4 from Coal Mining	-10.3	-12.3	n/a
CH_4 from Natural Gas Systems	+3.6	+1.8	n/a
CO_2 from NG flaring	+0.2	+0.1	n/a
Total CH_4 + CO_2	**-6.5**	**-10.3**	n/a

Note: A Global Warming Potential of 25 was used to convert methane emissions to CO_2e.

3A.2.3 Uncertainties and Limitations

Projections of upstream CH_4 emissions and CO_2 emitted from flaring of CH_4 are subject to a range of uncertainties and limitations. These uncertainties and limitations include estimating the effect of the compliance approach on activity drivers, uncertainty in base year emissions, and uncertainties in changes in emissions factors over relatively long periods of time. For example, EPA's application of IPM relies on EIA projections for coal imports and exports. Consequently, coal imports and exports are not able to fully respond within the IPM framework to significant fluctuations in power sector coal demand. To the extent international markets may be expected to offset reduced domestic coal demand, changes in U.S. upstream emissions as a result of the policy scenarios would be smaller than what is presented here.

Discussion of uncertainty in historical estimates of emissions from coal mining and natural gas systems can be found in the 2013 U.S. GHG Inventory. Projected changes in activity drivers and emissions factors are based on a combination of policy, macroeconomic, energy market, and technology factors which are uncertain in both baseline and compliance scenarios. Relatively higher or lower economic growth, or changes in the relative prices or availability of various technologies could result in alternative estimates in the net change in upstream CH_4 emissions and related CO_2 emissions.

3A.3 Methodologies

3A.3.1 Coal Mining

The scope of CH_4 from coal mining emissions covered in this analysis is discussed above in the "General Approach" section.

Methodology

EPA calculated emissions projections for this source by summing emissions associated with underground mining, post-underground mining, surface mining, and post-surface mining.

$$Emissions_y = \sum_s Emissions_{y,s}$$

Equation 3

Where:

s = Sources (underground, post-underground, surface, and post-surface mining)

$Emissions_{y,s}$ = Emissions in year y from source s

EPA projected emissions from each source by multiplying an aggregate emissions factor by projected coal production (for underground or surface mining as appropriate). Projected reductions due to recovery and use are then subtracted from potential emissions.[71]

[71] Current CH_4 recovery and use projects apply to underground mining, but projects related to surface mining could be implemented in the future.

$$Emissions_{y,s} = EF_{agg,s} \times InventoryProduction_{b,s} \times \left(\frac{ProjectedProduction_{y,s}}{ProjectedProduction_{b,s}}\right) \times (1 - CH_4RecoveryUseFrac_s)$$

Equation 4

Where:

$EF_{agg,s}$	=	Aggregate emissions factor associated with source *s*
$InventoryProduction_{b,s}$	=	Coal production associated with source s in the base year from the U.S. GHG Inventory[72]
$ProjectedProduction_{y,s}$	=	Projected coal production associated with the emissions source (e.g., either underground or surface mining) in year y
$CH_4RecoveryUseFrac_s$	=	Fraction of CH_4 recovered from source s

Emissions Factors

To calculate potential emissions from each category, EPA calculated an aggregate CH_4 emissions factor using historical CH_4 emissions and coal production data contained in the most recent U.S. GHG Inventory (EPA 2013a). For example, historical CH_4 liberated by underground mining was divided by the total underground coal production for the corresponding year. The aggregate emissions factor is the average of this ratio over the most recent five years. Similar calculations were performed for post-underground mining emissions, surface mining emissions, and post-surface mining emissions, using either historical underground or surface mining production data as appropriate.

The projection methodology differs from the estimation methodology used in the U.S. GHG Inventory. The inventory does not use emissions factors to calculate CH_4 emissions from underground mines. The U.S. GHG Inventory estimates total CH_4 emitted from underground mines as the sum of CH_4 liberated from ventilation systems (mine-by-mine measurements) and

[72] Because of slight differences between historical and projection datasets, values for production in the base year from each dataset do not cancel

CH_4 liberated by means of degasification systems, minus CH_4 recovered and used. EPA estimated surface mining and post-mining CH_4 emissions by multiplying basin-specific coal production, obtained from EIA's *Annual Coal Report* (EIA 2012), by basin-specific emissions factors.

Coal Production Projections

For the Sixth U.S. Climate Action Report, EPA projected emissions using projections of underground, surface, and total coal production from the EIA *Annual Energy Outlook (AEO)* (EIA 2013). For this analysis, projections of total coal production and production by region were drawn from IPM runs performed for the proposal RIA. Projections of underground and surface mining were not available outputs for the various scenarios, so two different approaches were used to estimate underground and surface mining in the baseline and compliance scenarios.

The 2013 *AEO* projects the total coal production for the United States, as well as the coal production by region, and by various characteristics including underground and surface mining (see AEO table "Coal Production by Region and Type"). In the primary results presented above, the breakout between underground and surface mining for projection years in both baseline and compliance scenarios is based on the *2013 AEO* proportions. This means that the compliance approach is assumed not to affect the relative proportion of underground and surface mining in the main results. Also, note there has been a general trend toward increasing surface mining relative to underground mining (EPA 2013).

In the sensitivity analysis that incorporated more geographical details into coal production, EPA used IPM outputs for coal production from the Appalachian, Interior, and Western regions to estimate the proportion of underground versus surface mining in each scenario. This was done by assuming that the relative proportion of underground versus surface mining in each coal production region would remain constant through the projection period, but that the national proportion of underground and surface production would depend on regional production changes. In general, a larger proportion of coal production in the Appalachian and Interior regions is from underground mining, while a large majority of coal production in western regions is from surface mining. The proportion of underground and surface mining in each region was based on averaging the years 2011 and 2012 historical percentages. EIA provides historical regional coal production data broken out between underground and surface mining in its *Annual Coal Report* (EIA 2012). EPA collated and calculated the proportion of production, underground versus surface, for each year.

CH_4 Mitigation (Recovery and Use)

EPA projected coal mine CH_4 mitigation by calculating the historical fraction of methane recovered in relation to generation from underground mines, and applying that fraction to future generation. The historical fraction was averaged over the most recent five years. Future mitigation was estimated by applying the historical rate of recovery and use to projected potential emissions generated.

The U.S. GHG Inventory uses quantitative estimates of CH_4 recovery and use from several sources. Several gassy underground coal mines in the United States employ ventilation systems to ensure that CH_4 levels remain within safe concentrations. Additionally, some U.S. coal mines supplement ventilation systems with degasification systems, which remove CH_4 from the mine and allow the captured CH_4 to be used as an energy source.

$$CH_4RecoveryUseFrac_s = \sum_{y=b}^{b-4} \frac{CH4RecoveryUse_{s,y}}{PotentialEmissions_{s,y}} \Big/ 5$$

Equation 5

Where:

$CH_4RecoveryUse_{s,y}$	=	Recovered emissions from source s in year y
$Potential\ Emissions_{s,y}$	=	Potential emissions from source s in year *y*
b	=	base year

3A.3.2 Natural Gas Systems

The scope of CH_4 and CO_2 from natural gas systems emissions covered in this analysis are discussed above in the “General Approach” section.

Methodology

The methodology for natural gas emissions projections involves the calculation of CH_4

and CO_2 emissions for over 100 emissions source categories across the four natural gas sector stages, and then the summation of emissions for each sector stage. The calculation of emissions for each source of emissions in natural gas systems generally occurs in three steps:

1. Calculate potential CH_4 (CH_4 that would be released in the absence of controls)
2. Estimate reductions data associated with voluntary action and regulations
3. Calculate net emissions

EPA calculated projections of potential CH_4 emissions from natural gas systems by summing the projections associated with (1) production, (2) processing, (3) transmission and storage, and (4) distribution. For the 2014 U.S. Climate Action Report in general, activity data were projections of natural gas production and consumption from the Department of Energy's Energy Information Administration, or EIA (EIA 2013). Additional activity data for projections included liquefied natural gas (LNG) imports, pipeline length, and number of service lines. For this report, activity driver data were taken from IPM outputs for baseline and compliance scenarios consistent with the analysis presented in the RIA. Because the base year inventory emissions explicitly include reductions due to voluntary and regulatory requirements, the projections also include appropriate explicit mitigation projections as well. Emissions for each source were estimated using the following equation:

$$NE_{s,y} = PE_{s,y} - VR_{s,y} - RR_{s,y} \qquad \text{Equation 6}$$

Where:

$NE_{s,y}$ = Projected net emissions for source *s* in year *y*

$PE_{s,y}$ = Projected potential emissions for source *s* in year *y*

$VR_{s,y,\,y}$ = Projected voluntary reductions for source *s* in year *y*

$RR_{s,y,\,y}$ = Projected regulatory reductions for source *s* in year *y*

The sections below describe detailed calculations for projections of CH_4 from natural gas systems. This analysis also includes CO_2 emissions that result from flaring in the production sector.[73] The U.S. Greenhouse Gas Inventory also includes other sources of venting, fugitive, and flaring CO_2 such as CO_2 processing emissions from acid gas removal units, which are designed to remove CO_2 from natural gas. This analysis does not include these other non-combustion CO_2 sources. EPA calculated projected flaring CO_2 emissions by scaling emissions in the base year by the increase in projected natural gas production in the IPM scenario outputs consistent with the analysis presented in the RIA.

Production Stage

The production stage includes a total of 35 emissions source categories. Regional emissions were estimated in the base year inventory for the six supply regions (i.e., Northeast, Gulf Coast, Midcontinent, Southwest, Rocky Mountain, and West Coast) for 33 of these sources.

Potential Emissions

EPA estimated future year potential emissions for the production stage using the following equation.

[73] The GHG Inventory estimate for CO_2 from natural gas flaring includes some CO_2 from flaring of associated gas.

$$PE_{s,y} = PE_{s,b} \times \left(\frac{Gas\ Production_y}{Gas\ Production_b}\right)$$

Equation 7

Where:

$PE_{s,y,\ y}$	=	Projected future potential emissions for source *s* in year *y*
$PE_{s,b,\ b}$	=	Estimated potential emissions for source *s* in base year *b*
$Gas\ Production_y$	=	Projected natural gas dry production year *y*
$Gas\ Production_b$	=	Estimated natural gas dry production for base year *b*

The natural gas dry production estimates were obtained from the IPM scenario outputs.

Voluntary Reductions

Projections of voluntary reductions for the production stage were based on historical data reported by industry to the Natural Gas STAR program for projects implemented to reduce emissions. Natural Gas STAR tracks projects on an annual basis and assigns a lifetime of limited duration to each reduction project; for purposes of the base year emissions inventory and the future year projections, the reductions associated with each project were either considered to be a "one-year" project or a "permanent" project based on sunset dates provided by the Natural Gas STAR program. Reductions from "one-year" projects were typically from the implementation of new or modified practices, while reductions from "permanent" projects tended to be from equipment installation, replacement, or modification. In the base year emissions inventory and the future year projections, reductions for a "one-year" project were limited to the project's reported start year, while reductions for a "permanent" project were assigned to the project's reported start year and every subsequent year thereafter. Thus, the reductions due to "permanent" projects gradually accumulated throughout the inventory time series, while the reductions due to "one-year" projects were replaced every year.

The following production stage voluntary reductions were reported to Natural Gas STAR and applied to individual sources in the emissions inventory:

- Completions for gas wells with hydraulic fracturing (one year)—perform reduced emissions completions (RECs).[74]
- Pneumatic device vents (one year)—reduce gas pressure on pneumatic devices; capture/use gas released from gas-operated pneumatic pumps.
- Pneumatic device vents (permanent)—identify and replace high-bleed pneumatic devices; convert pneumatic devices to mechanical controls; convert to instrument air systems; install no-bleed controllers.
- Kimray pumps (permanent)—install/convert gas-driven pumps to electric, mechanical, or solar pumps.
- Gas engines compressor exhaust (one year)—replace ignition/reduce false starts; turbine fuel use optimization.
- Gas engines compressor exhaust (permanent)—convert engine starting to Nitrogen- and/or CO_2-rich gas; install automated air/fuel ratio controls; install lean burn compressors; replace gas starters with air or N.

In addition to these reductions that were applied to specific individual sources in the emissions inventory, there were reductions classified as "Other Production" that were applied to the overall production stage emissions.

It was assumed that the percentage of voluntary reductions relative to potential CH_4 in the most recent base year inventory for the production stage would remain constant in each subsequent future year.[75] In addition, implementation of the Oil and Natural Gas Sector New

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[74] The 2014 GHG Inventory includes an update to the methodology for calculating emissions from hydraulically fractured gas well completions and workovers. The update uses control/practice-specific emission factors and no longer uses potential methane, or reductions data from Gas STAR or from regulations to calculate emissions, as emissions are directly calculated using the emission factors.

[75] The assumption of a constant rate of voluntary reductions relative to the base year inventory for sources unaffected by regulatory changes is meant to simulate a constant level of effort toward voluntary reductions into the future. No enhancements to the voluntary program are assumed. This assumption is a source of uncertainty; due to the voluntary nature of the program, reduction levels can fluctuate based on participation and investment. Where new regulatory requirements apply to new and modified equipment, voluntary reductions are assumed to continue to apply to existing equipment, but no voluntary reductions are applied to new equipment. As a potential

Source Performance Standards (NSPS)—discussed further below—necessitates the reclassification of certain production reductions from voluntary to regulatory.

Regulatory Reductions

As part of the regulatory reductions for the production stage, reductions due to existing Oil and Natural Gas Sector National Standards for Hazardous Air Pollutants (NESHAP) requirements (EPA. 2012a) for dehydrator vents and condensate tanks without control devices were included in the base year inventory. These reductions were carried forward in the future year projections.

In addition, the base year inventory accounted for state-level requirements in Wyoming and Colorado for RECs.[76] In the base year inventory, a national-level reduction was estimated by applying a 95 percent REC reduction to the fraction of national emissions occurring in Wyoming and Colorado (i.e., 15.1 percent); this resulted in a national-level reduction of 14.35 percent for gas well completions and workovers with hydraulic fracturing. These reductions were modified as described below.

The Oil and Natural Gas Sector NSPS for VOCs (EPA 2012a, finalized in 2012) significantly increased the amount of regulatory reductions applicable to the production stage, resulting in substantial CH_4 emissions reductions co-benefits. These reductions are not currently reflected in the 2013 U.S. GHG Inventory for the base year 2011, but are projected for future years as discussed in detail below. The specific Oil and Natural Gas Sector NSPS requirements impact the following production stage sources with regard to VOC (and the associated CH_4) emissions:

- Hydraulically fractured natural gas well completions

future improvement to these projections, EPA may develop an alternate methodology to model equipment turnover. However, a revised and reviewed methodology that incorporates equipment turnover is would likely be developed within the context of preparing the Agency's submission to the next Climate Action Report, which will probably be in the 2017 to 2018 timeframe.

[76] The 2014 GHG Inventory includes an update to the methodology for calculating emissions from hydraulically fractured gas well completions and workovers. The update uses control/practice-specific emission factors and no longer uses potential methane, or reductions data from Gas STAR or from regulations to calculate emissions, as emissions are directly calculated using the emission factors.

- Hydraulically refractured natural gas well recompletions
- New and modified high-bleed, gas-driven pneumatic controllers
- New storage tanks (with VOC emissions of 6 tons per year or more)
- New and modified reciprocating and centrifugal compressors at gathering and boosting stations

The impact of these requirements on the future year projections is discussed below. The specific quantitative reductions calculated for these projections are based on information from the Oil and Natural Gas Sector NSPS *Background Technical Support Document for the Proposed Standards* (EPA 2011) and the *Background Supplemental Technical Support Document for the Final New Source Performance Standards* (EPA 2012b), referred to collectively in this document as the Oil and Natural Gas Sector NSPS TSD.

Hydraulically Fractured Well Completions

The Oil and Natural Gas Sector NSPS requires the use of RECs (or "green completions") for all new hydraulically-fractured natural gas well completions. A phase-in period prior to January 1, 2015, also allows for the alternate use of a completion combustion device (i.e., flare), instead of RECs. In addition, RECs are not required for exploratory "wildcat" wells, delineation wells (i.e., used to define the borders of a natural gas reservoir), and low-pressure wells (i.e., completions where well pressure is too low to perform RECs); in these instances, emissions must be reduced using combustion. Based on the Oil and Natural Gas Sector NSPS TSD (EPA 2012b), EPA assumed for the purpose of these projections a 95 percent reduction for both RECs and completion combustion.[77]

Although the base year inventory included a national-level reduction of 14.35 percent to account for the required use of RECs in Wyoming and Colorado, there does not appear to be an

[77] The Oil and Natural Gas Sector NSPS TSD indicates that 90 percent of flowback gas can be recovered during an REC (based on Natural Gas STAR data) and that any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions. The Oil and Natural Gas Sector NSPS TSD indicates that although industrial flares are required to meet a combustion efficiency of 98 percent, this is not required for completion combustion devices. Completion combustion devices (i.e., exploration and production flares) can be expected to achieve 95 percent combustion efficiency.

appreciable difference in emissions reductions resulting from the Oil and Natural Gas Sector NSPS requirements and the state requirements in Wyoming and Colorado. Therefore, for future year projections, the national-level reduction of 14.35 percent was replaced with a 95 percent reduction for new hydraulically fractured well completions.

Hydraulically Refractured Well Workovers

The Oil and Natural Gas Sector NSPS also requires the use of RECs for gas wells that are refractured and recompleted. The phase-in period before January 1, 2015, is also applicable.[78] As with completions, a 95 percent reduction was assumed for both RECs and completion combustion. This replaced the national-level reduction of 14.35 percent that was used in the base year inventory.

For both well completions and workovers (or refractured well completions) with hydraulic fracturing, in conjunction with the Oil and Natural Gas Sector NSPS, EPA removed REC-related reductions from the projected voluntary reductions from the production stage to avoid double-counting. This removal was very straightforward, since these REC-related reductions were calculated separately and then applied to the well completions and workovers source in the base year inventory.

New and Modified High-Bleed, Gas-Driven Pneumatic Controllers

The Oil and Natural Gas Sector NSPS also requires the installation of new low-bleed pneumatic devices (i.e., bleed rates less than or equal to 6 standard cubic feet per hour) instead of high-bleed pneumatic devices (i.e., bleed rates greater than 6 standard cubic feet per hour) with exceptions where high bleed devices are required for safety reasons. The TSD indicates that a typical production stage high-bleed pneumatic device emits 6.91 tons of CH_4 per year and that replacing the high-bleed device with a typical low-bleed pneumatic device would result in a reduction of 6.65 tons CH_4 per year; this is a reduction of 96.2 percent. The TSD also indicates that only 51 percent of all pneumatic devices installed are continuous bleed natural gas driven controllers. In addition, it is assumed that 20 percent of the situations where bleed pneumatic

[78] Use of RECs is not considered to be "modified" and would not trigger state permitting requirements, while use of flaring or completion combustion would be considered to be "modified."

devices are installed require a high-bleed device (i.e., instances where a minimal response time is needed, large valves require a high bleed rate to actuate, or a safety isolation valve is involved) (EPA 2011). Based on this information, for the purpose of these projections EPA applied a national-level reduction of 77 percent (i.e., 0.962 × 0.8) to each future year's annual increase in emissions from pneumatic device vents in the production stage.

In conjunction with the Oil and Natural Gas Sector NSPS, no removal of production stage voluntary reductions was required. The reductions included in the base year inventory already occurred in the past and the associated effects carry forward into the future or were unrelated to the requirements of the Oil and Natural Gas Sector NSPS.

New Storage Tanks

The Oil and Natural Gas Sector NSPS also requires that new storage tanks with VOC emissions of 6 tons per year or greater must reduce VOC emissions by at least 95 percent, likely to be accomplished by routing emissions to a combustion device or rerouting emissions into process streams. The Oil and Natural Gas Sector NSPS TSD indicates that approximately 74 percent of the total condensate produced in the United States passes through storage tanks with VOC emissions of 6 tons per year or greater (EPA 2011). Based on this information, for the purpose of these projections EPA applied a national-level reduction of 70.3 percent (i.e., 0.95 × 0.74) to each future year's annual increase in emissions from condensate storage tanks in the production stage.

In conjunction with the Oil and Natural Gas Sector NSPS, no removal of production stage voluntary reductions associated with storage tanks was required. The reductions included in the base year inventory already occurred in the past and the associated effects carry forward into the future.

New and Modified Reciprocating Compressors

The Oil and Natural Gas Sector NSPS requires the replacement of rod packing systems in new and modified reciprocating compressors at gathering and boosting stations. There are two options for this replacement: every 26,000 hours of operation if operating hours are monitored and documented, or every 36 months if operating hours are not monitored or documented. The Oil and Natural Gas Sector NSPS TSD estimated baseline emissions of 3,773 tons per year of

CH_4 for new reciprocating compressors used in the production stage; the TSD also estimated total reductions from replacing the rod packing for these compressors as 2,384 tons per year of CH_4 (EPA 2011). Based on this information, for the purpose of these projections EPA applied a national-level reduction of 63.2 percent to each future year's annual increase in emissions from gathering reciprocating compressors in the production stage.

Processing Stage

The processing stage includes a total of 11 emissions source categories. EPA estimated the base year inventory emissions for the processing stage at the national level, instead of at the region level, like the base year inventory emissions for the production stage.

Potential Emissions

Because projections of future year processing activity were not available, EPA also used Equation 7 to estimate future year potential emissions for the processing stage by assuming that the quantity of processed natural gas would track closely with the quantity of produced natural gas.

As with the production stage, EPA used the natural gas dry production estimates from the IPM scenario outputs.

Voluntary Reductions

Projections of voluntary reductions for the processing stage were based on historical data reported by industry to the Natural Gas STAR program for projects implemented to reduce emissions (EPA 2012c). The following processing stage voluntary reductions were reported to Natural Gas STAR and applied to individual sources in the emissions inventory:

- Blowdowns/venting (one year)—recover gas from pipeline pigging operations; redesign blowdown/alter ESD practices; reduce emissions when taking compressors offline; use composite wrap repair; use hot taps for in-service pipeline connections; use inert gas and pigs to perform pipeline purges.
- Blowdowns/venting (permanent)—rupture pin shutoff device to reduce venting.

In addition to these reductions that were applied to specific individual sources in the emissions inventory, there were reductions classified as “Other Processing” that were applied to the overall processing stage emissions.

It was assumed that the percentage of voluntary reductions relative to potential CH_4 in the most recent base year inventory for the processing stage would remain constant in each subsequent future year.[79] In addition, implementation of the Oil and Natural Gas Sector NSPS (discussed further below) necessitates the reclassification of certain processing reductions from voluntary to regulatory.

Regulatory Reductions

The only regulatory reductions included in the base year inventory for the processing stage were existing Oil and Natural Gas Sector NESHAP requirements for dehydrator vents (EPA 2013). These reductions were carried forward in the future year projections.

The Oil and Natural Gas Sector NSPS significantly increased the amount of regulatory reductions applicable to the processing stage relative to the base year 2011 inventory estimates. The specific Oil and Natural Gas Sector NSPS requirements affect the following processing stage sources with regard to VOC (and the associated CH_4) emissions:

- New and modified reciprocating compressors
- New and modified centrifugal compressors
- New and modified high-bleed, gas-driven pneumatic controllers
- New storage tanks (with VOC emissions of at least 6 tons per year)

The impact of these requirements on the future year projections is discussed below.

New and Modified Reciprocating Compressors

The Oil and Natural Gas Sector NSPS requires the replacement of rod packing systems in new and modified reciprocating compressors. There are two options for this replacement: every 26,000 hours of operation if operating hours are monitored and documented, or every 36 months

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[79] This assumption is discussed in Footnote 7.

if operating hours are not monitored or documented. The Oil and Natural Gas Sector NSPS TSD estimated baseline emissions of 4,870 tons per year of CH_4 for new reciprocating compressors used in the processing stage; the Oil and Natural Gas Sector NSPS TSD also estimated total reductions from replacing the rod packing for these compressors as 3,892 tons per year of CH_4 (EPA 2011). Based on this information, for the purpose of these projections EPA applied a national-level reduction of 79.9 percent to each future year's annual increase in emissions from reciprocating compressors in the processing stage.

New and Modified Centrifugal Compressors

The Oil and Natural Gas Sector NSPS requires a 95 percent reduction in VOC emissions from new and modified centrifugal compressors with wet seal systems, which can be accomplished through flaring or by routing captured gas back to a compressor suction or fuel system, or switching to dry seal systems. The Oil and Natural Gas Sector NSPS does not apply to centrifugal compressors with dry seal systems, because they have low VOC emissions. A national-level reduction of 95 percent was applied to each future year's annual increase in emissions from centrifugal compressors with wet seals in the processing stage.

In conjunction with the Oil and Natural Gas Sector NSPS, no removal of processing stage voluntary reductions was required. The reductions included in the base year inventory already occurred in the past and the associated effects carry forward into the future or were unrelated to the requirements of the Oil and Natural Gas Sector NSPS.

New and Modified High-Bleed, Gas-Driven Pneumatic Controllers

The Oil and Natural Gas Sector NSPS also requires that the VOC emissions limit for continuous-bleed, gas-driven pneumatic controls at gas processing plants be zero. Accordingly, emissions from new pneumatic device vents in the processing stage were set to zero.

New Storage Tanks

As described above in the production sector.

Transmission and Storage Stage

The transmission and storage stage includes a total of 37 emissions source categories: 25

associated with natural gas transmission and storage and 12 associated with liquefied natural gas (LNG) transmission and storage. The natural gas and LNG emissions were estimated at the national level.

Potential Emissions

Future year potential emissions for the natural gas sources and the six LNG storage sources within the transmission and storage stage were estimated using the following equation:

$$PE_{s,y} = PE_{s,b} \times \left(\frac{Gas\ Consumption_y}{Gas\ Consumption_b}\right)$$

Equation 8

Where:

$PE_{s,y}$	=	Projected future potential emissions for source *s* in year *y*
$PE_{s,b}$	=	Estimated potential emissions for source *s* in base year *b*
$Gas\ Consumption_y$	=	Projected national natural gas consumption in year *y*
$Gas\ Consumption_b$	=	Estimated national natural gas consumption in base year *b*

The national natural gas consumption estimates were obtained from the IPM scenario outputs.

Future year potential emissions for the six LNG import terminal sources within the transmission and storage stage were estimated using the following equation:

$$PE_{s,y} = PE_{s,b} \times \left(\frac{LNG\ Imports_y}{LNG\ Imports_b}\right)$$

Equation 9

Where:

$PE_{s,y}$	=	Projected future potential emissions for source *s* in year *y*
$PE_{s,b}$	=	Estimated potential emissions for source *s* in base year *b*
$LNG\ Imports_y$	=	Projected LNG imports in year *y*
$LNG\ Imports_b$	=	Estimated LNG imports in base year *b*

The LNG import estimates were obtained from the table titled "Natural Gas Imports and Exports" of the IPM scenario outputs. The specific estimates used were for the "Liquefied Natural Gas Imports" line item.

Voluntary Reductions

Projections of voluntary reductions for the transmission and storage stage were also based on historical data reported by industry to the Natural Gas STAR program for projects implemented to reduce emissions. The following transmission and storage stage voluntary reductions were reported to Natural Gas STAR and applied to individual sources in the base year emissions inventory:

- Reciprocating compressors (one year)—replace compressor rod packing systems.
- Reciprocating compressors (permanent)—replace wet seals with dry seals.
- Pipeline venting (one year)—recover gas from pipeline pigging operations; use composite wrap repair; use hot taps for in-service pipeline connections; use inert gas and pigs to perform pipeline purges; use pipeline pump-down techniques to lower gas line pressure.
- Pneumatic devices (permanent)—identify and replace high-bleed pneumatic devices; convert pneumatic devices to mechanical controls; convert to instrument air systems.

In addition to these reductions that were applied to specific individual sources in the emissions inventory, there were reductions classified as "Other Transmission and Storage" that were applied to the overall transmission and storage stage emissions.

It was assumed that the percentage of voluntary reductions relative to potential CH_4 in the most recent base year inventory for the transmission and storage stage would remain constant in each subsequent future year.[80] In addition, implementation of the Oil and Natural Gas Sector NSPS (discussed further below) necessitates the reclassification of certain reductions from voluntary to regulatory.

[80] This assumption is discussed in Footnote 7.

Regulatory Reductions

No regulatory reductions were previously included in the inventory for the transmission and storage stage.

The Oil and Natural Gas Sector NSPS includes requirements applicable to the natural gas transmission and storage stage for VOC reductions of at least 95 percent for new storage tanks with VOC emissions of 6 tons per year or more.

The impact of these requirements on the future year projections is discussed below.

New Storage Tanks

As described above in the production sector.

Distribution Stage

The distribution stage includes a total of 23 emissions source categories consisting of 10 city gate sources, two customer meter sources, three vented sources, and eight pipeline leak sources. For all sources, emissions were estimated at the national level.

Potential Emissions

Because future year distribution projections were not available, EPA estimated future year potential emissions for the distribution stage (except for the pipeline leak sources) using Equation 3, assuming that the quantity of distributed natural gas tracks closely with the quantity of consumed natural gas.[81] The natural gas consumption estimates were obtained from the IPM scenario outputs. Sector-specific consumption estimates were used. For most sources (i.e., all city gate, all vented, and the residential customer meter sources), the "Natural Gas" line item

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[81] Many natural gas power plants are connected directly to transmission and distribution pipelines, and thus an increase in consumption of natural gas by power plants might not lead to a proportional change in CH_4 emissions from the distribution segment of the natural gas system. The current projection methodology uses total natural gas consumption as an activity driver to project emissions from non-pipeline leak sources in the distribution segment. EPA examined how the results would differ if the distribution segment were excluded. Depending on the scenario and year, the net emissions change between the base case and policy cases was reduced by up to 0.9 $TgCO_2e$ or increased by up to 0.4 $TgCO_2e$, assuming the change in power plant natural gas consumption had no effect on distribution-segment methane emissions.

under “Residential Consumption” was used. For the commercial/industry sources, EPA used the summation of the “Natural Gas” line item under “Commercial Consumption” and the “Natural Gas Subtotal” line item (including natural gas, natural gas-to-liquids heat and power, and lease and plant fuel) under “Industrial Consumption.”

Unlike most other sources in the natural gas systems emissions inventory, projected pipeline leak emissions in the distribution stage were not estimated using natural gas production or consumption estimates. Instead, linear extrapolation of historical pipeline miles was used to project leak emissions from distribution mains, while linear extrapolation of the historical number of service lines was used to project leak emissions from services. Linear extrapolation was used because the historical statistics for pipeline miles and number of services show fairly consistent behavioral trends over the entire time series from 1990 to 2011. In particular, the historical statistics show a distinct trend toward the use of plastic and away from other materials (i.e., cast iron, copper, unprotected steel, and protected steel). Historical pipeline length data was drawn from the US GHG Inventory (EPA 2013), which draws pipeline data from a variety of sources.

Voluntary Reductions

Projections of voluntary reductions for the distribution stage were based on historical data reported by industry to the Natural Gas STAR program for projects implemented to reduce emissions. Unlike the production, processing, and transmission and storage stages, no distribution stage voluntary reductions reported to Natural Gas STAR were applied to individual sources in the emissions inventory. However, there were reductions classified as “Other Distribution” that were applied to the overall distribution stage emissions.

It was assumed that the percentage of voluntary reductions relative to potential CH_4 in the most recent base year inventory for the transmission stage would remain constant in each subsequent future year.[82]

[82] This assumption is discussed in Footnote 7.

Regulatory Reductions

There were no requirements in the Oil and Natural Gas Sector NSPS that impact emissions from the distribution stage.

3A.4 References

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CHAPTER 4: ESTIMATED CLIMATE BENEFITS AND HUMAN HEALTH CO-BENEFITS

4.1 Introduction

Implementing the proposed Emission Guidelines for Greenhouse Gas (GHG) Emissions from Existing Stationary Sources: Electric Utility Generating Units (EGUs) (hereafter, EGU GHG Existing Source Guidelines) is expected to reduce emissions of carbon dioxide (CO_2) and have ancillary human health benefits (i.e., co-benefits) associated with lower ambient concentrations of criteria air pollutants. This chapter describes the methods used to estimate the monetized climate benefits and the monetized air pollution health co-benefits associated with reducing exposure to ambient fine particulate matter ($PM_{2.5}$) and ozone by reducing emissions of precursor pollutants (i.e., sulfur dioxide (SO_2), nitrogen dioxide (NO_2), and directly emitted $PM_{2.5}$). Data, resource, and methodological limitations prevent EPA from monetizing the benefits from several important co-benefit categories, including reducing direct exposure to SO_2, NO_2, and hazardous air pollutants (HAP), as well as ecosystem effects and visibility impairment. We qualitatively discuss these unquantified benefits in this chapter.

This chapter provides estimates of the monetized climate benefits and air pollution health co-benefits associated with emission reductions for two options with two illustrative compliance scenarios across several analysis years and discount rates. The estimated benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings, including the Mercury and Air Toxics Standards (MATS).

4.2 Estimated Climate Benefits from CO_2

The primary goal of the proposed guidelines is to reduce emissions of CO_2. In this section, we provide an overview of the climate science assessments released since the 2009 Endangerment Finding. We also provide information regarding the economic valuation of CO_2 using the Social Cost of Carbon (SCC), a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. Table 4-1 summarizes the quantified and unquantified climate benefits in this analysis.

Table 4-1. Climate Effects

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Environment				
Reduced climate effects	Global climate impacts from CO_2	—	✓	SCC TSD
	Climate impacts from ozone and black carbon (directly emitted PM)	—	—	Ozone ISA, PM ISA*
	Other climate impacts (e.g., other GHGs such as methane, aerosols, other impacts)	—	—	IPCC*

* We assess these co-benefits qualitatively because we do not have sufficient confidence in available data or methods.

4.2.1 Climate Change Impacts

In 2009, the EPA Administrator found that "six greenhouse gases taken in combination endanger both the public health and the public welfare of current and future generations."[83] The specific public health and public welfare impacts are detailed in the 2009 Endangerment Finding and its record.

A number of major peer-reviewed scientific assessments have been released since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial[84]. These assessments include the "Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation" (SREX) (IPCC, 2012), the 2013-14 Fifth Assessment Report (AR5) (IPCC, 2013, 2014a, 2014b), the 2014 National Climate Assessment report (Melillo et al., 2014), the "Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean" (Ocean Acidification) (NRC, 2010), "Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia" (Climate Stabilization Targets) (NRC, 2011a), "National Security Implications for U.S. Naval Forces" (National Security Implications) (NRC, 2011b), "Understanding Earth's Deep Past: Lessons for Our Climate Future" (Understanding Earth's Deep Past) (NRC, 2012a), "Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and

[83] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 Fed. Reg. 66,496 (Dec. 15, 2009) ("Endangerment Finding").

[84] "EPA's Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act", 75 Fed. Reg. 49,556 (Aug. 13, 2010) ("Reconsideration Denial").

Future" (NRC, 2012b), "Climate and Social Stress: Implications for Security Analysis" (Climate and Social Stress) (NRC, 2013a), and "Abrupt Impacts of Climate Change" (Abrupt Impacts) assessments (NRC, 2013b).

The EPA has reviewed these assessments and finds that in general, the improved understanding of the climate system they present are consistent with the assessments underlying the 2009 Endangerment Finding.

The IPCC report (IPCC, 2013), the National Climate Assessment (Melillo et al., 2014), and three of the new NRC assessments (NRC, 2011a, 2011b, 2012b) provide estimates of projected global sea level rise. These estimates, while not always directly comparable as they assume different emissions scenarios and baselines, are at least 40 percent larger than, and in some cases more than twice as large as, the rise estimated in a 2007 IPCC assessment (IPCC, 2007) of between 0.18 and 0.59 meters by the end of the century, relative to 1990. (It should be noted that in 2007, the IPCC stated that including poorly understood ice sheet processes could lead to an increase in the projections.) While these NRC and IPCC assessments continue to recognize and characterize the uncertainty inherent in accounting for ice sheet processes, these revised estimates are consistent with the assessments underlying the existing finding that GHGs are reasonably anticipated to endanger public health and welfare. Other key findings of the recent assessments are described briefly below.

According to the IPCC in the SREX (IPCC, 2012), "A changing climate leads to changes in the frequency, intensity, spatial extent, duration, and timing of extreme weather and climate events, and can result in unprecedented extreme weather and climate events." The SREX documents observational evidence of changes in some weather and climate extremes that have occurred globally since 1950. The assessment also provides evidence of anthropogenic influence (e.g., elevated concentrations of GHGs) regarding the cause of some of these changes, including warming of extreme daily temperatures, intensified extreme precipitation events, and increases in extreme coastal high water levels due to rising sea level. The SREX projects further increases in some extreme weather and climate events during the 21st century. Combined with increasing vulnerability and exposure of populations and assets, increases in extreme weather and climate events have consequences for disaster risk, with particular impacts on the water, agriculture and food security and health sectors.

In its Climate Stabilization Targets assessment (NRC, 2011a), the NRC states, "Emissions of carbon dioxide from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth's climate. Because carbon dioxide in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe."

The assessment concludes that carbon dioxide emissions will alter the atmosphere's composition and therefore the climate for thousands of years; and attempts to quantify the results of stabilizing GHG concentrations at different levels. The report also projects the occurrence of several specific climate change impacts, finding warming could lead to increases in heavy rainfall and decreases in crop yields and Arctic sea ice extent, along with other significant changes in precipitation and stream flow. For an increase in global average temperature of 1 to 2 ºC above pre-industrial levels, the assessment projects that the area burnt by wildfires in western North America will likely more than double and that coral bleaching events and coastal erosion are projected to increase due both to warming and ocean acidification. An increase of 3 ºC is projected to lead to a sea level rise of 0.5 to 1 meter by 2100. With an increase of 4 ºC, the average summer in the United States is projected to be as warm as the warmest summers of the past century. The assessment notes that although many important aspects of climate change are difficult to quantify, the risk of adverse impacts is likely to increase with increasing temperature, and the risk of surprises can be expected to increase with the duration and magnitude of the warming.

The NRC assessment on Sea Level Rise (NRC, 2012b) projects a global sea level rise of 0.5 to 1.4 meters by 2100, which is sufficient to lead to rising relative sea level even in the northern states. The NRC National Security Implications assessment (NRC, 2011b) considers potential impacts of sea level rise and suggests that "the Department of the Navy should expect roughly 0.4 to 2 meters global average sea-level rise by 2100." This assessment also recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats. The NRC Climate and Social Stress assessment (NRC, 2013a) found that it would be "prudent for security analysts to expect climate surprises in the coming decade . . . and for them to become progressively more serious and more frequent thereafter[.]"

The NRC Understanding Earth's Deep Past assessment (NRC, 2012a) finds that "the magnitude and rate of the present greenhouse gas increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history." This assessment finds that CO_2 concentrations by the end of the century, without a reduction in emissions, are projected to increase to levels that Earth has not experienced for more than 30 million years.

Similarly, the NRC Ocean Acidification assessment (NRC, 2010) finds that "[t]he chemistry of the ocean is changing at an unprecedented rate and magnitude due to anthropogenic carbon dioxide emissions; the rate of change exceeds any known to have occurred for at least the past hundreds of thousands of years." The assessment notes that the full range of consequences is still unknown, but the risks "threaten coral reefs, fisheries, protected species, and other natural resources of value to society."

The most recent assessments to be released were the IPCC AR5 assessments (IPCC, 2013, 2014a, 2014b) between September 2013 and April 2014, the NRC Abrupt Impacts assessment (NRC, 2013b) in December of 2013, and the U.S. National Climate Assessment (Melillo et al., 2014) in May of 2014. The NRC Abrupt Impacts report examines the potential for tipping points, thresholds beyond which major and rapid changes occur in the Earth's climate system or other systems impacted by the climate. The Abrupt Impacts report did find less cause for concern than some previous assessments regarding some abrupt events within the next century such as disruption of the Atlantic Meridional Overturning Circulation (AMOC) and sudden releases of high-latitude methane from hydrates and permafrost, but found that the potential for abrupt changes in ecosystems, weather and climate extremes, and groundwater supplies critical for agriculture now seem more likely, severe, and imminent. The assessment found that some abrupt changes were already underway (Arctic sea ice retreat and increases in extinction risk due to the speed of climate change), but cautioned that even abrupt changes such as the AMOC disruption that are not expected in this century can have severe impacts when they happen.

The IPCC AR5 assessments (IPCC, 2013, 2014a, 2014b) are also generally consistent with the underlying science supporting the 2009 Endangerment Finding. For example, confidence in attributing recent warming to human causes has increased: the IPCC stated that it is extremely likely (>95 percent confidence) that human influences have been the dominant cause of recent warming. Moreover, the IPCC found that the last 30 years were likely (>66 percent confidence) the warmest 30 year period in the Northern Hemisphere of the past 1400 years, that the rate of ice loss of worldwide glaciers and the Greenland and Antarctic ice sheets has likely increased, that there is medium confidence that the recent summer sea ice retreat in the Arctic is larger than has been in 1450 years, and that concentrations of carbon dioxide and several other of the major greenhouse gases are higher than they have been in at least 800,000 years. Climate-change induced impacts have been observed in changing precipitation patterns, melting snow and ice, species migration, negative impacts on crops, increased heat and decreased cold mortality, and altered ranges for water-borne illnesses and disease vectors. Additional risks from future changes include death, injury, and disrupted livelihoods in coastal zones and regions vulnerable to inland flooding, food insecurity linked to warming, drought, and flooding, especially for poor populations, reduced access to drinking and irrigation water for those with minimal capital in semi-arid regions, and decreased biodiversity in marine ecosystems, especially in the Arctic and tropics, with implications for coastal livelihoods. The IPCC determined that "[c]ontinued emissions of greenhouse gases will cause further warming and changes in all components of the climate system. Limiting climate change will require substantial and sustained reductions of greenhouse gases emissions."

Finally, the recently released National Climate Assessment (Melillo et al., 2014) stated, "Climate change is already affecting the American people in far reaching ways. Certain types of extreme weather events with links to climate change have become more frequent and/or intense, including prolonged periods of heat, heavy downpours, and, in some regions, floods and droughts. In addition, warming is causing sea level to rise and glaciers and Arctic sea ice to melt, and oceans are becoming more acidic as they absorb carbon dioxide. These and other aspects of climate change are disrupting people's lives and damaging some sectors of our economy."

Assessments from these bodies represent the current state of knowledge, comprehensively cover and synthesize thousands of individual studies to obtain the majority conclusions from the body of scientific literature and undergo a rigorous and exacting standard of review by the peer expert community and U.S. government.

4.2.2 Social Cost of Carbon

We estimate the global social benefits of CO_2 emission reductions expected from the proposed guidelines using the SCC estimates presented in the 2013 *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (2013 SCC TSD).[85] We refer to these estimates, which were developed by the U.S. government, as "SCC estimates." The SCC is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (i.e., benefits of rulemakings that have an incremental impact on cumulative global CO_2 emissions).

The SCC estimates used in this analysis were developed over many years, using the best science available, and with input from the public. The EPA and other federal agencies have considered the extensive public comments on ways to improve SCC estimation received via the notice and comment period that was part of numerous rulemakings since 2006. In addition, OMB's Office of Information and Regulatory Affairs recently sought public comment on the approach used to develop the SCC estimates. The comment period ended on February 26, 2014, and OMB is reviewing the comments received.

An interagency process that included the EPA and other executive branch entities used three integrated assessment models (IAMs) to develop SCC estimates and selected four global values for use in regulatory analyses. The SCC estimates were first released in February 2010

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[85] Docket ID EPA-HQ-OAR-2013-0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised November 2013). Available at: http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.

and updated in 2013 using new versions of each IAM. [86]

The SCC estimates represent global measures because of the distinctive nature of the climate change problem. The climate change problem is highly unusual in at least two respects. First, emissions of most GHGs contribute to damages around the world even when they are emitted in the United States. The SCC must therefore incorporate the full (global) damages caused by GHG emissions in order to address the global nature of the problem. Second, climate change presents a problem that the United States alone cannot solve. The US now operates in a global, highly interconnected economy such that impacts on the other side of the world now affect our economy. Climate damages in other countries can affect U.S. companies. Climate-exacerbated conflict can require military expenditures by the U.S. All of this means that the true cost of climate change to U.S. is much larger than impacts that simply occur in the U.S. Climate change presents a problem that the United States alone cannot solve. A global number is the economically appropriate reference point for collective actions to reduce climate change.

A key objective in the development of the SCC estimates was to enable a consistent exploration of three integrated assessment models (DICE, FUND, and PAGE)[87] while respecting the different approaches to quantifying damages taken by the key modelers in the field. The selection of the three input parameters (equilibrium climate sensitivity, reference socioeconomic scenarios, discount rate) was based on an extensive review of the literature. Specifically, a probability distribution for climate sensitivity was specified as an input into all three models. In addition, the interagency group used a range of scenarios for the socio-economic parameters and a range of values for the discount rate. All other model features were left unchanged, relying on the model developers' best estimates and judgments. In DICE, these parameters are handled deterministically and represented by fixed constants; in PAGE, most parameters are represented

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[86] Docket ID EPA-HQ-OAR-2009-0472-114577, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf. See previous citation for 2013 SCC TSD.

[87] The full models names are as follows: Dynamic Integrated Climate and Economy (DICE); Climate Framework for Uncertainty, Negotiation, and Distribution (FUND); and Policy Analysis of the Greenhouse Gas Effect (PAGE).

by probability distributions. FUND was also run in a mode in which parameters were treated probabilistically. The use of three models and these input parameters allowed for exploration of important uncertainties in the way climate damages are estimated, equilibrium climate sensitivity, reference socioeconomic and emission trajectories, and discount rate. As stated in the 2010 SCC TSD, however, key uncertainties remain as the existing models are imperfect and incomplete. See the 2010 SCC TSD for a complete discussion of the methods used to develop the estimates and the key uncertainties, and the 2013 SCC TSD for the updated estimates.

Notably, the 2013 process did not revisit the 2010 interagency modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios or equilibrium climate sensitivity). Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and used in peer-reviewed publications. The model updates that are relevant to the SCC estimates include: an explicit representation of sea level rise damages in the DICE and PAGE models; updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages in the PAGE model; an updated carbon cycle in the DICE model; and updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of methane emissions in the FUND model. The 2013 SCC TSD provides complete details.

When attempting to assess the incremental economic impacts of carbon dioxide emissions, the analyst faces a number of serious challenges. A report from the National Academies of Science (NRC, 2009) points out that any assessment will suffer from uncertainty, speculation, and lack of information about (1) future emissions of greenhouse gases, (2) the effects of past and future emissions on the climate system, (3) the impact of changes in climate on the physical and biological environment, and (4) the translation of these environmental impacts into economic damages.[88] As a result, any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and

[88] National Research Council (2009). Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use. National Academies Press. See docket ID EPA-HQ-OAR-2009-0472-11486.

should be viewed as provisional.

The 2010 SCC TSD noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Current integrated assessment models do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. The limited amount of research linking climate impacts to economic damages makes the modeling exercise even more difficult. These individual limitations do not all work in the same direction in terms of their influence on the SCC estimates, though taken together they suggest that the SCC estimates are likely conservative. In particular, the IPCC Fourth Assessment Report (2007) concluded that "It is very likely that [SCC estimates] underestimate the damage costs because they cannot include many non-quantifiable impacts."

Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 reductions to inform benefit-cost analysis. The new versions of the models used to estimate the values presented below offer some improvements in these areas, although further work remains warranted. Accordingly, the EPA and other agencies continue to engage in research on modeling and valuation of climate impacts with the goal to improve these estimates. Additional details are provided in the SCC TSDs.

The four SCC estimates, updated in 2013, are as follows: $13, $46, $68, and $137 per metric ton of CO_2 emissions in the year 2020 (2011$).[89] The first three values are based on the average SCC from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. SCC estimates for several discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by

[89] The 2010 and 2013 TSDs present SCC in 2007$. The estimates were adjusted to 2011$ using GDP Implicit Price Deflator, http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf.

different generations). The fourth value is the 95th percentile of the SCC from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution (representing less likely, but potentially catastrophic, outcomes).

Table 4-2 presents the updated global SCC estimates for the years 2015 to 2050. In order to calculate the dollar value for emission reductions, the SCC estimate for each emissions year would be applied to changes in CO_2 emissions for that year, and then discounted back to the analysis year using the same discount rate used to estimate the SCC.[90] The SCC increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change. Note that the interagency group estimated the growth rate of the SCC directly using the three integrated assessment models rather than assuming a constant annual growth rate. This helps to ensure that the estimates are internally consistent with other modeling assumptions. Tables 4-3 through 4-5 report the incremental climate benefits estimated in three analysis years (2020, 2025, and 2030) for the two illustrative compliance scenarios (i.e., state and regional) for two options evaluated.

[90] This analysis considered the climate impacts of only CO_2 emission change. As discussed below, the climate impacts of other pollutants were not calculated for the proposed guidelines. Furthermore, the U.S. Interagency Working Group on the Social Cost of Carbon has so far only considered estimates for the social cost of CO_2. While CO_2 is the dominant GHG emitted by the sector, we recognize the representative facilities within these comparisons may also have different emission rates for other climate forcers that will serve a minor role in determining the overall social cost of generation.

Table 4-2. Global Social Cost of CO_2, 2015-2050 (in 2011$)*

Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% (95th percentile)
2015	$12	$39	$61	$116
2020	$13	$46	$68	$137
2025	$15	$50	$74	$153
2030	$17	$55	$80	$170
2035	$20	$60	$85	$187
2040	$22	$65	$92	$204
2045	$26	$70	$98	$220
2050	$28	$76	$104	$235

* The SCC values vary depending on the year of CO_2 emissions and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator. These SCC values are stated in $/metric ton.

Table 4-3. Estimated Global Climate Benefits of CO_2 Reductions for Proposed EGU GHG Existing Source Guidelines in 2020 (billions of 2011$)*

Discount Rate and Statistic	Option 1 – state	Option 1 – regional	Option 2 – state	Option 2 - regional
Million metric tonnes of CO_2 reduced	383	371	295	283
5% (average)	$4.9	$4.7	$3.8	$3.6
3% (average)	$18	$17	$14	$13
2.5% (average)	$26	$25	$20	$19
3% (95th percentile)	$52	$51	$40	$39

* The SCC values are dollar-year and emissions-year specific. SCC values represent only a partial accounting of climate impacts.

Table 4-4. Estimated Global Climate Benefits of CO_2 Reductions for Proposed EGU GHG Existing Source Guidelines in 2025 (billions of 2011$)*

Discount Rate and Statistic	Option 1 – state	Option 1 - regional	Option 2 – state	Option 2 - regional
Million metric tonnes of CO_2 reduced	506	501	376	368
5% (average)	$7.6	$7.5	$5.6	$5.5
3% (average)	$25	$25	$19	$18
2.5% (average)	$37	$37	$28	$27
3% (95th percentile)	$77	$76	$57	$56

* The SCC values are dollar-year and emissions-year specific. SCC values represent only a partial accounting of climate impacts.

Table 4-5. Estimated Global Climate Benefits of CO_2 Reductions for Proposed EGU GHG Existing Source Guidelines in 2030 (billions of 2011$)*

Discount Rate and Statistic	Option 1 – state	Option 1 - regional	Option 2 – state	Option 2 - regional
Million metric tonnes of CO_2 reduced	555	545	n/a	n/a
5% (average)	$9.5	$9.3	n/a	n/a
3% (average)	$31	$30	n/a	n/a
2.5% (average)	$44	$44	n/a	n/a
3% (95th percentile)	$94	$92	n/a	n/a

* The SCC values are dollar-year and emissions-year specific. SCC values represent only a partial accounting of climate impacts.

It is important to note that the climate benefits presented above are associated with changes in CO_2 emissions only. Implementing these guidelines, however, will have an impact on the emissions of other pollutants that would affect the climate. Both predicting reductions in emissions and estimating the climate impacts of these other pollutants, however, is complex. The climate impacts of these other pollutants have not been calculated for the proposed guidelines.[91]

The other emissions potentially reduced as a result of these guidelines include other greenhouse gases (such as methane), aerosols and aerosol precursors such as black carbon, organic carbon, sulfur dioxide and nitrogen oxides, and ozone precursors such as nitrogen oxides and volatile organic carbon compounds. Changes in emissions of these pollutants (both increases and decreases) could directly result from changes in electricity generation, upstream fossil fuel extraction and transport, and/or downstream secondary market impacts. Reductions in black carbon or ozone precursors are projected to lead to further cooling, but reductions in the other aerosol species and precursors are projected to lead to warming. Therefore, changes in non-CO_2 pollutants could potentially augment or offset the climate benefits calculated here. These pollutants can act in different ways and on different timescales than carbon dioxide. For example, aerosols reflect (and in the case of black carbon, absorb) incoming radiation, whereas greenhouse gases absorb outgoing infrared radiation. In addition, these aerosols are thought to affect climate indirectly by altering properties of clouds. Black carbon can also deposit on snow and ice, darkening these surfaces and accelerating melting. In terms of lifetime, while carbon dioxide emissions can increase concentrations in the atmosphere for hundreds or thousands of years, many of these other pollutants are short lived and remain in the atmosphere for short periods of time ranging from days to weeks and can therefore exhibit large spatial and temporal variability.

While the EPA has not quantified the climate impacts of these other pollutants for the proposed guidelines, the Agency has analyzed the potential changes in upstream methane emissions from the natural gas and coal production sectors that may result from the compliance scenarios examined in this RIA in the appendix to Chapter 3. The EPA assessed whether the net change in upstream methane emissions from natural gas and coal production is likely to be

[91] The federal government's SCC estimates used in this analysis are designed to assess the climate benefits associated with changes in CO_2 emissions only.

positive or negative and also assessed the potential magnitude of changes relative to CO_2 emissions reductions anticipated at power plants. This assessment included CO_2 emissions from the flaring of methane, but did not evaluate potential changes in other combustion-related CO_2 emissions, such as emissions associated with drilling, mining, processing, and transportation in the natural gas and coal production sectors. This analysis found that the net upstream CH_4 emissions from natural gas systems and coal mines and CO_2 emissions from flaring of methane will likely decrease under the proposed guidelines. Furthermore, the analysis suggests that the changes in upstream methane emissions are small relative to the changes in direct emissions from power plants.

4.3 Estimated Human Health Co-Benefits

In addition to CO_2, implementing these proposed guidelines is expected to reduce emissions of SO_2 and NO_X, which are precursors to formation of ambient $PM_{2.5}$, as well as directly emitted fine particles.[92] Therefore, reducing these emissions would also reduce human exposure to ambient $PM_{2.5}$ and the incidence of $PM_{2.5}$-related health effects. In addition, in the presence of sunlight, NO_X and VOCs can undergo a chemical reaction in the atmosphere to form ozone. Depending on localized concentrations of volatile organic compounds (VOCs), reducing NO_X emissions would also reduce human exposure to ozone and the incidence of ozone-related health effects. Although we do not have sufficient data to quantify these impacts in this analysis, reducing emissions of SO_2 and NOx would also reduce ambient exposure to SO_2 and NO_2, respectively. In this section, we provide an overview of the monetized $PM_{2.5}$ and ozone-related co-benefits estimated for the proposed guidelines. The estimated co-benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings, including MATS. A full description of the underlying data, studies, and assumptions is provided in the PM NAAQS RIA (U.S. EPA, 2012a) and Ozone NAAQS RIA (U.S. EPA, 2008b, 2010d).

There are several important considerations in assessing the air pollution-related health co-benefits for a climate-focused rulemaking. First, these estimated health co-benefits do not

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[92] We estimate the health co-benefits associated with emission reductions of two categories of directly emitted particles: elemental carbon plus organic carbon (EC+OC) and crustal. Crustal emissions are composed of compounds associated with minerals and metals from the earth's surface, including carbonates, silicates, iron, phosphates, copper, and zinc. Often, crustal material represents particles not classified as one of the other species (e.g., organic carbon, elemental carbon, nitrate, sulfate, chloride, etc.).

account for any climate-related air quality changes (e.g., increased ambient ozone associated with higher temperatures) but rather changes in precursor emissions affected by this rulemaking. Excluding climate-related air quality changes may underestimate ozone-related health co-benefits. It is unclear how $PM_{2.5}$-related health co-benefits would be impacted by excluding climate-related air quality changes since the science is unclear as to how climate change may affect $PM_{2.5}$ exposure. Second, the estimated health co-benefits also do not consider temperature modification of $PM_{2.5}$ and ozone risks (Roberts 2004; Ren 2006a, 2006b, 2008a, 2008b). Third, the estimated climate benefits reported in this RIA reflect global benefits, while the estimated health co-benefits are calculated for the contiguous U.S. only. Excluding temperature modification of air pollution risks and international air pollution-related health benefits implies that the quantified health co-benefits likely lead to underestimation.

Implementing these guidelines may lead to reductions in ambient $PM_{2.5}$ concentrations below the National Ambient Air Quality Standards (NAAQS) for PM and ozone in some areas and assist other areas with attaining these NAAQS. Because the NAAQS RIAs (U.S. EPA, 2012a, 2008b, 2010d) also calculated PM and ozone benefits, there are important differences worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate the potential costs and benefits of attaining a revised air quality standard nationwide based on an array of emission reduction strategies for different sources including known and unknown controls, incremental to implementation of existing regulations and controls needed to attain the current standards. In short, NAAQS RIAs hypothesize, but do not predict, the reduction strategies that States may choose to enact when implementing a revised NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, EPA's NAAQS RIAs are merely illustrative and the estimated costs and benefits are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However, it is possible that some costs and benefits estimated in this RIA may account for the same air quality improvements as estimated in the illustrative NAAQS RIAs.

Similar to NAAQS RIAs, the emission reduction scenarios estimated for the proposed guidelines are also illustrative. In contrast to NAAQS RIAs, all of the emission reductions for the illustrative compliance scenarios would occur in one well-characterized sector (i.e., the EGU sector). In general, EPA is more confident in the magnitude and location of the emission reductions for implementation rules, which typically require specific emission reductions in a specific sector. As such, emission reductions achieved under promulgated implementation rules will ultimately be reflected in the baseline of future NAAQS analyses, which would reduce the incremental costs and benefits associated with attaining revised future NAAQS. EPA does not re-issue illustrative RIAs outside of the rulemaking process that retroactively update the baseline to account for implementation rules promulgated after an RIA was completed. For more information on the relationship between illustrative analyses, such as for the NAAQS and this proposal, and implementation rules, please see section 1.3 of the PM NAAQS RIA (U.S. EPA, 2012a).

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

The *Integrated Science Assessment for Particulate Matter* (PM ISA) (U.S. EPA, 2009b) identified the human health effects associated with ambient $PM_{2.5}$ exposure, which include premature morality and a variety of morbidity effects associated with acute and chronic exposures. Similarly, the *Integrated Science Assessment for Ozone and Related Photochemical Oxidants* (Ozone ISA) (U.S. EPA, 2013b) identified the human health effects associated with ambient ozone exposure, which include premature morality and a variety of morbidity effects associated with acute and chronic exposures. Table 4-6 identifies the quantified and unquantified co-benefit categories captured in EPA's health co-benefits estimates for reduced exposure to ambient $PM_{2.5}$ and ozone. Although the table below does not list unquantified health effects such as those associated with exposure to SO_2, NO_2, and mercury nor welfare effects such as acidification and nutrient enrichment, these effects are described in detail in Chapters 5 and 6 of the PM NAAQS RIA (U.S. EPA, 2012a) and summarized later in this chapter. It is important to emphasize that the list of unquantified benefit categories is not exhaustive, nor is quantification of each effect complete.

Table 4-6. Human Health Effects of Ambient $PM_{2.5}$ and Ozone

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Human Health				
Reduced incidence of premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	✓	✓	PM ISA
	Infant mortality (age <1)	✓	✓	PM ISA
Reduced incidence of morbidity from exposure to $PM_{2.5}$	Non-fatal heart attacks (age > 18)	✓	✓	PM ISA
	Hospital admissions—respiratory (all ages)	✓	✓	PM ISA
	Hospital admissions—cardiovascular (age >20)	✓	✓	PM ISA
	Emergency room visits for asthma (all ages)	✓	✓	PM ISA
	Acute bronchitis (age 8-12)	✓	✓	PM ISA
	Lower respiratory symptoms (age 7-14)	✓	✓	PM ISA
	Upper respiratory symptoms (asthmatics age 9-11)	✓	✓	PM ISA
	Asthma exacerbation (asthmatics age 6-18)	✓	✓	PM ISA
	Lost work days (age 18-65)	✓	✓	PM ISA
	Minor restricted-activity days (age 18-65)	✓	✓	PM ISA
	Chronic Bronchitis (age >26)	—	—	PM ISA[1]
	Emergency room visits for cardiovascular effects (all ages)	—	—	PM ISA[1]
	Strokes and cerebrovascular disease (age 50-79)	—	—	PM ISA[1]
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[2]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[2]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc)	—	—	PM ISA[2,3]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[2,3]
Reduced incidence of mortality from exposure to ozone	Premature mortality based on short-term study estimates (all ages)	✓	✓	Ozone ISA
	Premature mortality based on long-term study estimates (age 30–99)	—	—	Ozone ISA[1]
Reduced incidence of morbidity from exposure to ozone	Hospital admissions—respiratory causes (age > 65)	✓	✓	Ozone ISA
	Hospital admissions—respiratory causes (age <2)	✓	✓	Ozone ISA
	Emergency department visits for asthma (all ages)	✓	✓	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[1]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[2]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[2]
	Reproductive and developmental effects	—	—	Ozone ISA[2,3]

[1] We assess these co-benefits qualitatively due to data and resource limitations for this analysis, but we have quantified them in sensitivity analyses for other analyses.

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

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

We follow a "damage-function" approach in calculating benefits, which estimates changes in individual health endpoints (specific effects that can be associated with changes in air quality) and assigns values to those changes assuming independence of the values for those individual endpoints. Because EPA rarely has the time or resources to perform new research to measure directly, either health outcomes or their values for regulatory analyses, our estimates are based on the best available methods of benefits transfer, which is the science and art of adapting primary research from similar contexts to estimate benefits for the environmental quality change under analysis. We use a "benefit-per-ton" approach to estimate the $PM_{2.5}$ and ozone co-benefits in this RIA. This section describes the underlying basis for the health and economic valuation estimates, and the subsequent section provides an overview of the benefit-per-ton estimates, which are described in detail in the appendix to this chapter.

The health impact assessment (HIA) quantifies the changes in the incidence of adverse health impacts resulting from changes in human exposure to $PM_{2.5}$ and ozone. We use the environmental Benefits Mapping and Analysis Program (BenMAP) (version 4.0.66) to systematize health impact analyses by applying a database of key input parameters, including population projections, health impact functions, and valuation functions (Abt Associates, 2012). For this assessment, the HIA is limited to those health effects that are directly linked to ambient $PM_{2.5}$ and ozone concentrations. There may be other indirect health impacts associated with reducing emissions, such as occupational health exposures. Epidemiological studies generally provide estimates of the relative risks of a particular health effect for a given increment of air pollution (often per 10 $\mu g/m^3$ for $PM_{2.5}$ or ppb for ozone). These relative risks can be used to develop risk coefficients that relate a unit reduction in $PM_{2.5}$ to changes in the incidence of a health effect. We refer the reader to the PM NAAQS RIA (U.S. EPA, 2012a) and Ozone NAAQS RIA (U.S. EPA, 2008b, 2010d) for more information regarding the epidemiology studies and risk coefficients applied in this analysis, and we briefly elaborate on adult premature mortality below. The size of the mortality effect estimates from epidemiological studies, the serious nature of the effect itself, and the high monetary value ascribed to prolonging life make mortality risk reduction the most significant health endpoint quantified in this analysis.

4.3.1.1 Mortality Concentration-Response Functions for $PM_{2.5}$

Considering a substantial body of published scientific literature and reflecting thousands of epidemiology, toxicology, and clinical studies, the PM ISA documents the association between elevated $PM_{2.5}$ concentrations and adverse health effects, including increased premature mortality (U.S. EPA, 2009b). The PM ISA, which was twice reviewed by the Clean Air Scientific Advisory Committee of EPA's Science Advisory Board (SAB-CASAC) (U.S. EPA-SAB, 2009b, 2009c), concluded that there is a causal relationship between mortality and both long-term and short-term exposure to $PM_{2.5}$ based on the entire body of scientific evidence. The PM ISA also concluded that the scientific literature consistently finds that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response function. In addition to adult mortality discussed in more detail below, we use effect coefficients from Woodruff et al. (1997) to estimate PM-related infant mortality.

For adult PM-related mortality, we use the effect coefficients from the most recent epidemiology studies examining two large population cohorts: the American Cancer Society cohort (Krewski et al., 2009) and the Harvard Six Cities cohort (Lepeule et al., 2012). The PM ISA (U.S. EPA, 2009b) concluded that the ACS and Six Cities cohorts provide the strongest evidence of the association between long-term $PM_{2.5}$ exposure and premature mortality with support from a number of additional cohort studies. The SAB's Health Effects Subcommittee (SAB-HES) also supported using these two cohorts for analyses of the benefits of PM reductions (U.S. EPA-SAB, 2010a). As both the ACS and Six Cities cohort studies have inherent strengths and weaknesses, we present $PM_{2.5}$ co-benefits estimates using relative risk estimates from both these cohorts (Krewski et al., 2009; Lepeule et al., 2012).

As a characterization of uncertainty regarding the adult $PM_{2.5}$-mortality relationship, EPA graphically presents the $PM_{2.5}$ co-benefits derived from EPA's expert elicitation study (Roman et al., 2008; IEc, 2006). The primary goal of the 2006 study was to elicit from a sample of health experts probabilistic distributions describing uncertainty in estimates of the reduction in mortality among the adult U.S. population resulting from reductions in ambient annual average $PM_{2.5}$ concentrations. In that study, twelve experts provided independent opinions regarding the $PM_{2.5}$-mortality concentration-response function. Because the experts relied upon the ACS and

Six Cities cohort studies to inform their concentration-response functions, the benefits estimates derived from the expert responses generally fall between results derived from these studies (see Figure 4-1). We do not combine the expert results in order to preserve the breadth and diversity of opinion on the expert panel. This presentation of the expert-derived results is generally consistent with SAB advice (U.S. EPA-SAB, 2008), which recommended that the EPA emphasize that "scientific differences existed only with respect to the magnitude of the effect of $PM_{2.5}$ on mortality, not whether such an effect existed" and that the expert elicitation "supports the conclusion that the benefits of $PM_{2.5}$ control are very likely to be substantial". Although it is possible that newer scientific literature could revise the experts' quantitative responses if elicited again, we believe that these general conclusions are unlikely to change.

4.3.1.2 Mortality Concentration-Response Functions for Ozone

In 2008, the National Academies of Science (NRC, 2008) issued a series of recommendations to the EPA regarding the quantification and valuation of ozone-related short-term mortality. Chief among these was that "…short-term exposure to ambient ozone is likely to contribute to premature deaths" and the committee recommended that "ozone-related mortality be included in future estimates of the health benefits of reducing ozone exposures…" The NAS also recommended that "…the greatest emphasis be placed on the multicity and NMMAPS [*National Morbidity, Mortality, and Air Pollution Study]* studies without exclusion of the meta-analyses" (NRC, 2008). In view of the findings of the National Academies panel, we estimate the co-benefits of avoiding short-term ozone mortality using the Bell et al. (2004) NMMAPS analysis, the Schwartz (2005) multi-city study, the Huang et al. (2005) multi-city study as well as effect estimates from the three meta-analyses (Bell et al. (2005), Levy et al. (2005), and Ito et al. (2005)). These studies are consistent with the studies used in the Ozone NAAQS RIA (U.S. EPA, 2008b, 2010d).[93] For simplicity, we report the ozone mortality estimates in this RIA as a range from Bell et al. (2004) to Levy et al. (2005) to represent the lowest and the highest co-benefits estimates based on these six ozone mortality studies. In addition, we graphically present

[93] Since EPA received NAS advice, EPA published the Ozone ISA (U.S. EPA, 2013b) and the second draft Ozone Health Risk and Exposure Assessment (U.S. EPA, 2014a). Therefore, the ozone mortality studies applied in this analysis, while current at the time of the previous Ozone NAAQS RIAs, do not reflect the most updated literature available. The selection of ozone mortality studies used to estimate benefits in RIAs will be revisited in the forthcoming RIA accompanying the on-going review of the Ozone NAAQS.

estimated co-benefits derived from all six studies mentioned above as a characterization of uncertainty regarding the ozone -mortality relationship in Figure 4-1.

4.3.2 Economic Valuation for Health Co-benefits

After quantifying the change in adverse health impacts, we estimate the economic value of these avoided impacts. Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health effects by a small amount for a large population. Therefore, the appropriate economic measure is willingness to pay (WTP) for changes in risk of a health effect. For some health effects, such as hospital admissions, WTP estimates are generally not available, so we use the cost of treating or mitigating the effect. These cost-of-illness (COI) estimates generally (although not necessarily in every case) understate the true value of reductions in risk of a health effect. They tend to reflect the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect. The unit values applied in this analysis are provided in Table 5-9 of the PM NAAQS RIA for each health endpoint (U.S. EPA, 2012a).

Avoided premature deaths account for 98 percent of monetized PM-related co-benefits and over 90 percent of monetized ozone-related co-benefits. The economics literature concerning the appropriate method for valuing reductions in premature mortality risk is still developing. The adoption of a value for the projected reduction in the risk of premature mortality is the subject of continuing discussion within the economics and public policy analysis community. Following the advice of the SAB's Environmental Economics Advisory Committee (SAB-EEAC), the EPA currently uses the value of statistical life (VSL) approach in calculating estimates of mortality benefits, because we believe this calculation provides the most reasonable single estimate of an individual's willingness to trade off money for reductions in mortality risk (U.S. EPA-SAB, 2000). The VSL approach is a summary measure for the value of small changes in mortality risk experienced by a large number of people.

EPA continues work to update its guidance on valuing mortality risk reductions, and the Agency consulted several times with the SAB-EEAC on this issue. Until updated guidance is available, the Agency determined that a single, peer-reviewed estimate applied consistently, best reflects the SAB-EEAC advice it has received. Therefore, EPA has decided to apply the VSL that was vetted and endorsed by the SAB in the Guidelines for Preparing Economic Analyses

(U.S. EPA, 2000)[94] while the Agency continues its efforts to update its guidance on this issue. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is $6.3 million (2000$).[95] We then adjust this VSL to account for the currency year and to account for income growth from 1990 to the analysis year. Specifically, the VSLs applied in this analysis in 2011$ after adjusting for income growth are $9.9 million for 2020 and $10.1 million for 2025 and 2030.[96]

The Agency is committed to using scientifically sound, appropriately reviewed evidence in valuing mortality risk reductions and has made significant progress in responding to the SAB-EEAC's specific recommendations. In the process, the Agency has identified a number of important issues to be considered in updating its mortality risk valuation estimates. These are detailed in a white paper, "Valuing Mortality Risk Reductions in Environmental Policy" (U.S. EPA, 2010c), which recently underwent review by the SAB-EEAC. A meeting with the SAB on this paper was held on March 14, 2011 and formal recommendations were transmitted on July 29, 2011 (U.S. EPA-SAB, 2011). EPA is taking SAB's recommendations under advisement.

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

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[94] In the updated *Guidelines for Preparing Economic Analyses* (U.S. EPA, 2010e), EPA retained the VSL endorsed by the SAB with the understanding that further updates to the mortality risk valuation guidance would be forthcoming in the near future.

[95] In 1990$, this base VSL is $4.8 million.

[96] Income growth projections are only currently available in BenMAP through 2024, so both the 2025 and 2030 estimates use income growth only through 2024 and are therefore likely underestimates.

the estimated ozone-related co-benefits are identical for all discount rates.

4.3.3 Benefit-per-ton Estimates for $PM_{2.5}$

We used a "benefit-per-ton" approach to estimate the $PM_{2.5}$ co-benefits in this RIA. EPA has applied this approach in several previous RIAs (e.g., U.S. EPA, 2011b, 2011c, 2012b). These benefit-per-ton estimates provide the total monetized human health co-benefits (the sum of premature mortality and premature morbidity), of reducing one ton of $PM_{2.5}$ (or $PM_{2.5}$ precursor such as NO_X or SO_2) from a specified source. Specifically, in this analysis, we multiplied the estimates for the EGU sector by the corresponding emission reductions based on regional (i.e., East, West, and California) benefit-per-ton estimates.

The method used to calculate the regional benefit-per-ton estimates is a slight modification of the national benefit-per-ton estimates described in the TSD: *Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors* (U.S. EPA, 2013a). The national estimates were derived using the approach published in Fann et al. (2012), but they have since been updated to reflect the epidemiology studies and Census population data first applied in the final PM NAAQS RIA (U.S. EPA, 2012a). The approach in Fann et al. (2012) is similar to the work previously published by Fann et al. (2009), but the newer study includes improvements that provide more refined estimates of $PM_{2.5}$-related health benefits for emissions reductions in the various sectors. Specifically, the air quality modeling data reflect industrial sectors that are more narrowly defined. In addition, the updated air quality modeling data reflects more recent emissions data (2005 rather than 2001) and has higher spatial resolution (12km rather than 36 km grid cells).[97] For this rulemaking, to generate the regional benefit-per-ton estimates we simply aggregated the EGU impacts in BenMAP to the region (i.e., East, West, and California) rather than aggregating to the nation as was done in Fann et al. (2012). We then divided the regional benefits by the regional emissions rather than the national emissions. The appendix to this chapter provides additional detail regarding these calculations.

As noted below in the characterization of uncertainty, all benefit-per-ton estimates have

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[97] Although the modeling underlying the benefit-per-ton estimates does not reflect emission reductions anticipated from MATS, the EGU contribution to ambient $PM_{2.5}$ and ozone on a per-ton basis would be similar. (Fann, Fulcher, and Baker, 2013) Because the emission reductions in this RIA are calculated from an IPM base case that includes MATS (see Chapter 3), there is no double-counting concern with the resulting co-benefits estimates.

inherent limitations. Specifically, all benefit-per-ton estimates reflect the geographic distribution of the modeled sector emissions, which may not match the emission reductions anticipated by the proposed guidelines, and they may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. In addition, these estimates reflect the regional average benefit-per-ton for each ambient $PM_{2.5}$ precursor emitted from EGUs, which assumes a linear atmospheric response to emission reductions. The regional benefit-per-ton estimates, although less subject to these types of uncertainties than national estimates, still should be interpreted with caution. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure.

4.3.4 Benefit-per-ton Estimates for Ozone

Similar to $PM_{2.5}$, we used a "benefit-per-ton" approach in this RIA to estimate the ozone co-benefits, which represent the total monetized human health co-benefits (the sum of premature mortality and premature morbidity) of reducing one ton of NOx (an ozone precursor). Also consistent with the $PM_{2.5}$ estimates, we generated regional benefit-per-ton estimates for ozone for the EGU sector using the air quality modeling data described in Fann et al. (2012) and using the updated Census population data first applied in the final PM NAAQS RIA (U.S. EPA, 2012a). In contrast to the $PM_{2.5}$ estimates, the ozone estimates are not based on changes to annual emissions. Instead, the regional estimates (i.e., East, West, and California) correspond to NO_X emissions from U.S. EGUs during the ozone-season (May to September). Because we estimate ozone health impacts from May to September only, this approach underestimates ozone co-benefits in areas with a longer ozone season such as southern California and Texas. These estimates assume that EGU-attributable ozone formation at the regional-level is due to NOx alone. Because EGUs emit little VOC relative to NO_X emissions, it is unlikely that VOCs emitted by EGUs would contribute substantially to regional ozone formation. All benefit-per-ton estimates have inherent limitations and should be interpreted with caution. We provide more detailed information regarding the generation of these estimates in the appendix to this chapter.

4.3.5 Estimated Health Co-Benefits Results

Tables 4-7 through 4-9 provide the national and regional benefit-per-ton estimates for 2020, 2025, and 2030. Tables 4-10 through 4-12 provide the emission reductions estimated to occur in three analysis years (2020, 2025, and 2030) for two illustrative compliance scenarios (i.e., state and regional) for two options by region (i.e., East, West, and California).[98] Tables 4-13 through 4-15 summarize the national monetized PM and ozone-related health co-benefits estimated to occur in three analysis years (2020, 2025, and 2030) for the options by precursor pollutant using discount rates of 3 percent and 7 percent. Tables 4-16 through 4-18 provide national summaries of the reductions in health incidences estimated for the options associated with these pollution reductions in 2020, 2025, and 2030. Figure 4-1 provides a visual representation of the range of estimated $PM_{2.5}$ and ozone-related co-benefits using concentration-response functions from different studies and expert opinion for the options evaluated in 2020 as an illustrative analysis year. Figures 4-2 and 4-3 provide a breakdown of the monetized health co-benefits for each of the options evaluated in 2020 as an illustrative analysis year by precursor pollutant and region, respectively.

[98] See Chapter 3 of this RIA for more information regarding the expected emission reductions used to calculate the health co-benefits in this chapter. Chapter 3 also provides more information regarding the illustrative compliance scenarios.

Table 4-7. Summary of National and Regional Benefit-per-ton Estimates for EGUs in 2020 (2011$)*

Pollutant	Discount Rate	National	Regional		
			East	West	California
SO_2	3%	$38,000 to $86,000	$40,000 to $90,000	$7,800 to $18,000	$160,000 to $320,000
	7%	$34,000 to $77,000	$36,000 to $82,000	$7,100 to $16,000	$140,000 to $320,000
Directly emitted $PM_{2.5}$ (EC+OC)	3%	$140,000 to $320,000	$140,000 to $320,000	$56,000 to $130,000	$280,000 to $570,000
	7%	$130,000 to $290,000	$130,000 to $280,000	$50,000 to $110,000	$250,000 to $570,000
Directly emitted $PM_{2.5}$ (crustal)	3%	$18,000 to $40,000	$18,000 to $41,000	$11,000 to $25,000	$110,000 to $220,000
	7%	$16,000 to $36,000	$16,000 to $37,000	$10,000 to $23,000	$95,000 to $220,000
NO_X (as $PM_{2.5}$)	3%	$5,600 to $13,000	$6,700 to $15,000	$1,200 to $2,600	$17,000 to $34,000
	7%	$5,000 to $11,000	$6,000 to $14,000	$1,000 to $2,400	$15,000 to $34,000
NO_X (as Ozone)	N/A	$3,800 to $16,000	$4,600 to $19,000	$930 to $4,000	$7,400 to $31,000

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for $PM_{2.5}$ and ozone. All estimates are rounded to two significant figures. The monetized co-benefits do not include reduced health effects from direct exposure to NO_2, SO_2, ecosystem effects, or visibility impairment. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ concentrations, which drive population exposure. The monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. Benefit-per-ton estimates for ozone are based on ozone season NO_X emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski et al. (2009) and Lepeule et al. (2012).

Table 4-8. Summary of National and Regional Benefit-per-Ton Estimates for EGUs in 2025 (2011$)*

Pollutant	Discount Rate	National	Regional		
			East	West	California
SO_2	3%	$41,000 to $93,000	$44,000 to $98,000	$8,800 to $20,000	$180,000 to $410,000
	7%	$37,000 to $84,000	$39,000 to $89,000	$8,000 to $18,000	$160,000 to $370,000
Directly emitted $PM_{2.5}$ (EC+OC)	3%	$150,000 to $350,000	$150,000 to $340,000	$64,000 to $140,000	$320,000 to $720,000
	7%	$140,000 to $310,000	$140,000 to $310,000	$58,000 to $130,000	$290,000 to $650,000
Directly emitted $PM_{2.5}$ (crustal)	3%	$17,000 to $39,000	$18,000 to $40,000	$12,000 to $27,000	$43,000 to $96,000
	7%	$15,000 to $35,000	$16,000 to $36,000	$11,000 to $24,000	$38,000 to $87,000
NO_X (as $PM_{2.5}$)	3%	$6,000 to $14,000	$7,200 to $16,000	$1,300 to $2,900	$19,000 to $42,000
	7%	$5,400 to $12,000	$6,500 to $15,000	$1,200 to $2,600	$17,000 to $38,000
NO_X (as Ozone)	N/A	$4,900 to $21,000	$5,900 to $25,000	$1,200 to $5,400	$9,900 to $42,000

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for $PM_{2.5}$ and ozone. All estimates are rounded to two significant figures. The monetized co-benefits do not include reduced health effects from direct exposure to NO_2, SO_2, ecosystem effects, or visibility impairment. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ concentrations, which drive population exposure. The monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. Benefit-per-ton estimates for ozone are based on ozone season NO_X emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski et al. (2009) and Lepeule et al. (2012).

Table 4-9. Summary of National and Regional Benefit-per-Ton Estimates for EGUs in 2030 (2011$)*

Pollutant	Discount Rate	National	Regional		
			East	West	California
SO_2	3%	$44,000 to $100,000	$47,000 to $110,000	$9,800 to $22,000	$200,000 to $450,000
	7%	$40,000 to $90,000	$42,000 to $95,000	$8,800 to $20,000	$180,000 to $410,000
Directly emitted $PM_{2.5}$ (EC+OC)	3%	$170,000 to $370,000	$160,000 to $370,000	$71,000 to $160,000	$360,000 to $800,000
	7%	$150,000 to $340,000	$150,000 to $330,000	$64,000 to $150,000	$320,000 to $730,000
Directly emitted $PM_{2.5}$ (crustal)	3%	$18,000 to $42,000	$19,000 to $43,000	$13,000 to $30,000	$47,000 to $110,000
	7%	$17,000 to $38,000	$17,000 to $38,000	$12,000 to $27,000	$43,000 to $96,000
NO_X (as $PM_{2.5}$)	3%	$6,400 to $14,000	$7,600 to $17,000	$1,400 to $3,200	$21,000 to $42,000
	7%	$5,800 to $13,000	$6,900 to $16,000	$1,300 to $2,900	$19,000 to $47,000
NO_X (as Ozone)	N/A	$5,300 to $23,000	$6,300 to $27,000	$1,400 to $6,000	$11,000 to $47,000

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for $PM_{2.5}$ and ozone. All estimates are rounded to two significant figures. The monetized co-benefits do not include reduced health effects from direct exposure to NO_2, SO_2, ecosystem effects, or visibility impairment. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ concentrations, which drive population exposure. The monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. Benefit-per-ton estimates for ozone are based on ozone season NO_X emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski et al. (2009) and Lepeule et al. (2012).

Table 4-10. Emission Reductions of Criteria Pollutants for the Proposed EGU GHG Existing Source Guidelines in 2020 (thousands of short tons)*

Region	SO_2	All-year NOx	Ozone-Season NOx	Directly emitted $PM_{2.5}$ (EC+OC)	Directly emitted $PM_{2.5}$ (crustal)
Option 1 - State					
East	311	315	135	5	41
West	25	51	22	<1	4
California	<1	1	1	N/A	N/A
National Total	335	367	157	6	45
Option 1 - Regional					
East	279	305	130	5	41
West	10	32	13	0	3
California	2	8	3	N/A	N/A
National Total	292	345	146	6	44
Option 2 - State					
East	247	240	101	4	35
West	20	40	18	<1	3
California	<1	1	1	N/A	N/A
National Total	267	281	119	5	38
Option 2 - Regional					
East	234	235	97	4	33
West	8	25	11	<1	2
California	2	8	3	N/A	N/A
National Total	244	268	111	5	36

*All emissions shown in the table are rounded, so regional emission reductions may appear to not sum to national total.

Table 4-11. Emission Reductions of Criteria Pollutants for the Proposed EGU GHG Existing Source Guidelines in 2025 (thousands of short tons)*

Region	SO_2	All-year NOx	Ozone-Season NOx	Directly emitted $PM_{2.5}$ (EC+OC)	Directly emitted $PM_{2.5}$ (crustal)
Option 1 - State					
East	395	378	164	6	44
West	30	53	23	1	6
California	1	5	2	N/A	N/A
National Total	425	436	190	6	49
Option 1 - Regional					
East	376	372	160	5	42
West	16	34	15	1	4
California	3	16	5	N/A	N/A
National Total	395	421	180	6	46
Option 2 - State					
East	301	271	114	4	34
West	25	42	20	<1	4
California	1	4	2	N/A	N/A
National Total	327	317	136	5	38
Option 2 - Regional					
East	281	270	113	4	32
West	13	24	11	<1	3
California	3	14	5	N/A	N/A
National Total	297	309	129	4	34

*All emissions shown in the table are rounded, so regional emission reductions may appear to not sum to national total.

Table 4-12. Emission Reductions of Criteria Pollutants for the Proposed EGU GHG Existing Source Guidelines in 2030 (thousands of short tons)*

Region	SO_2	All-year NOx	Ozone-Season NOx	Directly emitted $PM_{2.5}$ (EC+OC)*	Directly emitted $PM_{2.5}$ (crustal)*
Option 1 - State					
East	441	376	163	5	39
West	30	52	24	1	5
California	<1	<1	<1	N/A	N/A
National Total	471	428	187	6	44
Option 1 - Regional					
East	406	366	158	5	39
West	16	33	15	<1	4
California	2	7	3	N/A	N/A
National Total	424	407	176	5	42

*All emissions shown in the table are rounded, so regional emission reductions may appear to not sum to national total.

Table 4-13. Summary of Estimated Monetized Health Co-Benefits for the Proposed EGU GHG Existing Source Guidelines in 2020 (millions of 2011$) *

Pollutant	3% Discount Rate			7% Discount Rate		
Option 1 - State						
SO_2	$13,000	to	$29,000	$11,000	to	$26,000
Directly emitted $PM_{2.5}$ (EC+OC)	$760	to	$1,700	$690	to	$1,600
Directly emitted $PM_{2.5}$ (crustal)	$790	to	$1,800	$710	to	$1,600
NOx (as $PM_{2.5}$)	$2,200	to	$4,900	$2,000	to	$4,400
NOx (as Ozone)	$640	to	$2,700	$640	to	$2,700
Total	**$17,000**	**to**	**$40,000**	**$15,000**	**to**	**$36,000**
Option 1 - Regional						
SO_2	$12,000	to	$26,000	$11,000	to	$24,000
Directly emitted $PM_{2.5}$ (EC+OC)	$750	to	$1,700	$670	to	$1,500
Directly emitted $PM_{2.5}$ (crustal)	$770	to	$1,700	$690	to	$1,600
NOx (as $PM_{2.5}$)	$2,200	to	$5,000	$2,000	to	$4,500
NOx (as Ozone)	$630	to	$2,700	$630	to	$2,700
Total	**$16,000**	**to**	**$37,000**	**$15,000**	**to**	**$34,000**
Option 2 - State						
SO_2	$10,000	to	$23,000	$9,100	to	$21,000
Directly emitted $PM_{2.5}$ (EC+OC)	$640	to	$1,500	$580	to	$1,300
Directly emitted $PM_{2.5}$ (crustal)	$660	to	$1,500	$600	to	$1,400
NOx (as $PM_{2.5}$)	$1,700	to	$3,800	$1,500	to	$3,400
NOx (as Ozone)	$480	to	$2,100	$480	to	$2,100
Total	**$14,000**	**to**	**$32,000**	**$12,000**	**to**	**$29,000**
Option 2 - Regional						
SO_2	$9,800	to	$22,000	$8,900	to	$20,000
Directly emitted $PM_{2.5}$ (EC+OC)	$610	to	$1,400	$550	to	$1,200
Directly emitted $PM_{2.5}$ (crustal)	$630	to	$1,400	$570	to	$1,300
NOx (as $PM_{2.5}$)	$1,700	to	$3,900	$1,600	to	$3,500
NOx (as Ozone)	$470	to	$2,000	$470	to	$2,000
Total	**$13,000**	**to**	**$31,000**	**$12,000**	**to**	**$28,000**

* All estimates are rounded to two significant figures so numbers may not sum down columns. The estimated monetized co-benefits do not include climate benefits or reduced health effects from direct exposure to NO_2, SO_2, ecosystem effects, or visibility impairment. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. Co-benefits for $PM_{2.5}$ precursors are based on regional benefit-per-ton estimates. Co-benefits for ozone are based on ozone season NOx emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski et al. (2009) and Lepeule et al. (2012).

Table 4-14. Summary of Estimated Monetized Health Co-Benefits for the Proposed EGU GHG Existing Source Guidelines in 2025 (millions of 2011$) *

Pollutant	3% Discount Rate			7% Discount Rate		
Option 1 - State						
SO_2	$18,000	to	$40,000	$16,000	to	$36,000
Directly emitted $PM_{2.5}$ (EC+OC)	$900	to	$2,000	$810	to	$1,800
Directly emitted $PM_{2.5}$ (crustal)	$830	to	$1,900	$750	to	$1,700
NOx (as $PM_{2.5}$)	$2,900	to	$6,500	$2,600	to	$5,800
NOx (as Ozone)	$1,000	to	$4,400	$1,000	to	$4,400
Total	**$23,000**	**to**	**$54,000**	**$21,000**	**to**	**$49,000**
Option 1 - Regional						
SO_2	$17,000	to	$38,000	$15,000	to	$35,000
Directly emitted $PM_{2.5}$ (EC+OC)	$850	to	$1,900	$760	to	$1,700
Directly emitted $PM_{2.5}$ (crustal)	$780	to	$1,800	$700	to	$1,600
NOx (as $PM_{2.5}$)	$3,000	to	$6,800	$2,700	to	$6,100
NOx (as Ozone)	$1,000	to	$4,300	$1,000	to	$4,300
Total	**$23,000**	**to**	**$53,000**	**$21,000**	**to**	**$48,000**
Option 2 - State						
SO_2	$14,000	to	$30,000	$12,000	to	$27,000
Directly emitted $PM_{2.5}$ (EC+OC)	$690	to	$1,600	$630	to	$1,400
Directly emitted $PM_{2.5}$ (crustal)	$640	to	$1,400	$580	to	$1,300
NOx (as $PM_{2.5}$)	$2,100	to	$4,700	$1,900	to	$4,200
NOx (as Ozone)	$720	to	$3,100	$720	to	$3,100
Total	**$18,000**	**to**	**$41,000**	**$16,000**	**to**	**$37,000**
Option 2 - Regional						
SO_2	$13,000	to	$29,000	$12,000	to	$26,000
Directly emitted $PM_{2.5}$ (EC+OC)	$640	to	$1,400	$580	to	$1,300
Directly emitted $PM_{2.5}$ (crustal)	$590	to	$1,300	$530	to	$1,200
NOx (as $PM_{2.5}$)	$2,200	to	$5,000	$2,000	to	$4,500
NOx (as Ozone)	$730	to	$3,100	$730	to	$3,100
Total	**$17,000**	**to**	**$40,000**	**$16,000**	**to**	**$36,000**

* All estimates are rounded to two significant figures so numbers may not sum down columns. The estimated monetized co-benefits do not include climate benefits or reduced health effects from direct exposure to NO_2, SO_2, ecosystem effects, or visibility impairment. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. Co-benefits for $PM_{2.5}$ precursors are based on regional benefit-per-ton estimates. Co-benefits for ozone are based on ozone season NOx emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski et al. (2009) and Lepeule et al. (2012).

Table 4-15. Summary of Estimated Monetized Health Co-Benefits for the Proposed EGU GHG Existing Source Guidelines in 2030 (millions of 2011$) *

Pollutant	3% Discount Rate			7% Discount Rate		
Option 1 - State						
SO_2	$21,000	to	$47,000	$19,000	to	$43,000
Directly emitted $PM_{2.5}$ (EC+OC)	$870	to	$2,000	$780	to	$1,800
Directly emitted $PM_{2.5}$ (crustal)	$800	to	$1,800	$720	to	$1,600
NOx (as $PM_{2.5}$)	$2,900	to	$6,600	$2,600	to	$6,000
NOx (as Ozone)	$1,100	to	$4,600	$1,100	to	$4,600
Total	**$27,000**	**to**	**$62,000**	**$24,000**	**to**	**$57,000**
Option 1 - Regional						
SO_2	$20,000	to	$44,000	$18,000	to	$40,000
Directly emitted $PM_{2.5}$ (EC+OC)	$840	to	$1,900	$760	to	$1,700
Directly emitted $PM_{2.5}$ (crustal)	$770	to	$1,700	$700	to	$1,600
NOx (as $PM_{2.5}$)	$3,000	to	$6,700	$2,700	to	$6,100
NOx (as Ozone)	$1,100	to	$4,500	$1,100	to	$4,500
Total	**$25,000**	**to**	**$59,000**	**$23,000**	**to**	**$54,000**

* All estimates are rounded to two significant figures so numbers may not sum down columns. The estimated monetized co-benefits do not include climate benefits or reduced health effects from direct exposure to NO_2, SO_2, ecosystem effects, or visibility impairment. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. Co-benefits for $PM_{2.5}$ precursors are based on regional benefit-per-ton estimates. Co-benefits for ozone are based on ozone season NOx emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95^{th} percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski et al. (2009) and Lepeule et al. (2012).

Table 4-16. Summary of Avoided Health Incidences from $PM_{2.5}$-Related and Ozone-Related Co-benefits for Proposed EGU GHG Existing Source Guidelines in 2020*

	Option 1 - state	Option 1 - regional	Option 2 - state	Option 2 - regional
$PM_{2.5}$-related Health Incidences				
Avoided Premature Mortality				
Krewski et al. (2009) (adult)	1,800	1,700	1,400	1,400
Lepeule et al. (2012) (adult)	4,100	3,800	3,200	3,200
Woodruff et al. (1997) (infant)	4	4	3	3
Avoided Morbidity				
Emergency department visits for asthma (all ages)	950	890	760	740
Acute bronchitis (age 8–12)	2,600	2,500	2,100	2,000
Lower respiratory symptoms (age 7–14)	33,000	31,000	27,000	26,000
Upper respiratory symptoms (asthmatics age 9–11)	48,000	45,000	38,000	38,000
Minor restricted-activity days (age 18–65)	1,300,000	1,200,000	1,000,000	1,000,000
Lost work days (age 18–65)	220,000	210,000	180,000	170,000
Asthma exacerbation (age 6–18)	100,000	95,000	82,000	80,000
Hospital admissions—respiratory (all ages)	530	490	420	410
Hospital admissions—cardiovascular (age > 18)	650	610	520	500
Non-Fatal Heart Attacks (age >18)				
Peters et al. (2001)	2,100	1,900	1,600	1,600
Pooled estimate of 4 studies	220	210	180	170
Ozone-related Health Incidences				
Avoided Premature Mortality				
Bell et al. (2004) (all ages)	36	35	27	27
Levy et al. (2005) (all ages)	170	160	120	120
Avoided Morbidity				
Hospital admissions—respiratory causes (ages > 65)	220	210	160	160
Hospital admissions—respiratory causes (ages < 2)	100	98	76	74
Emergency room visits for asthma (all ages)	120	110	89	87
Minor restricted-activity days (ages 18-65)	210,000	210,000	160,000	160,000
School absence days	72,000	71,000	55,000	54,000

* All estimates are rounded to whole numbers with two significant figures. Co-benefits for $PM_{2.5}$ precursors are based on regional benefit-per-ton estimates for all precursors. Co-benefits for ozone are based on ozone season NOx emissions. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95th percentile confidence interval for the health impact function alone ranges from approximately ±30 percent for mortality incidence based on Krewski et al. (2009) and ±46 percent based on Lepeule et al. (2012).

Table 4-17. Summary of Avoided Health Incidences from $PM_{2.5}$-Related and Ozone-Related Co-benefits for Proposed EGU GHG Existing Source Guidelines in 2025*

	Option 1 - state	Option 1 - regional	Option 2 - state	Option 2 - regional
$PM_{2.5}$-related Health Incidences				
Avoided Premature Mortality				
Krewski et al. (2009) (adult)	2,400	2,300	1,800	1,800
Lepeule et al. (2012) (adult)	5,400	5,300	4,100	4,000
Woodruff et al. (1997) (infant)	5	5	4	4
Avoided Morbidity				
Emergency department visits for asthma (all ages)	1,200	1,200	930	900
Acute bronchitis (age 8–12)	3,400	3,300	2,600	2,500
Lower respiratory symptoms (age 7–14)	43,000	43,000	33,000	32,000
Upper respiratory symptoms (asthmatics age 9–11)	63,000	62,000	48,000	46,000
Minor restricted-activity days (age 18–65)	1,700,000	1,600,000	1,300,000	1,200,000
Lost work days (age 18–65)	280,000	280,000	210,000	210,000
Asthma exacerbation (age 6–18)	130,000	130,000	100,000	100,000
Hospital admissions—respiratory (all ages)	730	710	560	540
Hospital admissions—cardiovascular (age > 18)	890	870	680	650
Non-Fatal Heart Attacks (age >18)				
Peters et al. (2001)	2,800	2,700	2,100	2,100
Pooled estimate of 4 studies	310	300	230	220
Ozone-related Health Incidences				
Avoided Premature Mortality				
Bell et al. (2004) (all ages)	93	92	65	66
Levy et al. (2005) (all ages)	420	420	300	300
Avoided Morbidity				
Hospital admissions—respiratory causes (ages > 65)	600	600	430	430
Hospital admissions—respiratory causes (ages < 2)	250	240	180	180
Emergency room visits for asthma (all ages)	290	290	210	210
Minor restricted-activity days (ages 18-65)	520,000	520,000	370,000	370,000
School absence days	180,000	180,000	130,000	130,000

* All estimates are rounded to whole numbers with two significant figures. Co-benefits for $PM_{2.5}$ precursors are based on regional benefit-per-ton estimates for all precursors. Co-benefits for ozone are based on ozone season NOx emissions. In general, the 95th percentile confidence interval for the health impact function alone ranges from approximately ±30 percent for mortality incidence based on Krewski et al. (2009) and ±46 percent based on Lepeule et al. (2012).

Table 4-18. Summary of Avoided Health Incidences from $PM_{2.5}$-Related and Ozone-Related Co-Benefits for Proposed EGU GHG Existing Source Guidelines in 2030*

	Option 1 - state	Option 1 - regional
$PM_{2.5}$-related Health Incidences		
Avoided Premature Mortality		
Krewski et al. (2009) (adult)	2,700	2,600
Lepeule et al. (2012) (adult)	6,200	5,900
Woodruff et al. (1997) (infant)	5	5
Avoided Morbidity		
Emergency department visits for asthma (all ages)	1,400	1,300
Acute bronchitis (age 8–12)	3,700	3,500
Lower respiratory symptoms (age 7–14)	48,000	45,000
Upper respiratory symptoms (asthmatics age 9–11)	69,000	66,000
Minor restricted-activity days (age 18–65)	1,800,000	1,700,000
Lost work days (age 18–65)	310,000	290,000
Asthma exacerbation (age 6–18)	150,000	140,000
Hospital admissions—respiratory (all ages)	870	820
Hospital admissions—cardiovascular (age > 18)	1,000	980
Non-Fatal Heart Attacks (age >18)		
Peters et al. (2001)	3,300	3,100
Pooled estimate of 4 studies	360	340
Ozone-related Health Incidences		
Avoided Premature Mortality		
Bell et al. (2004) (all ages)	97	96
Levy et al. (2005) (all ages)	440	430
Avoided Morbidity		
Hospital admissions—respiratory causes (ages > 65)	670	660
Hospital admissions—respiratory causes (ages < 2)	250	240
Emergency room visits for asthma (all ages)	290	290
Minor restricted-activity days (ages 18-65)	510,000	510,000
School absence days	180,000	180,000

* All estimates are rounded to whole numbers with two significant figures. Co-benefits for $PM_{2.5}$ precursors are based on regional benefit-per-ton estimates for all precursors. Co-benefits for ozone are based on ozone season NOx emissions. In general, the 95th percentile confidence interval for the health impact function alone ranges from approximately ±30 percent for mortality incidence based on Krewski et al. (2009) and ±46 percent based on Lepeule et al. (2012).

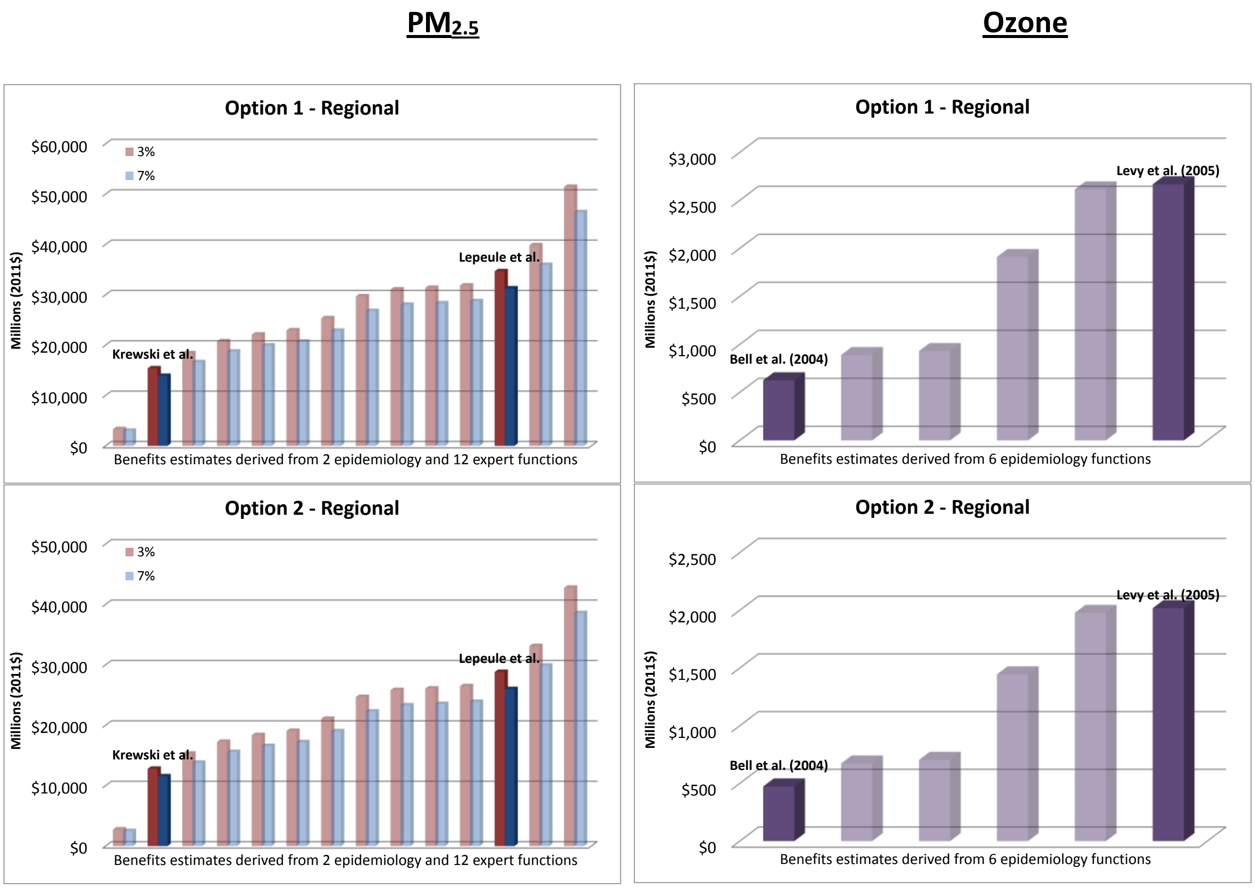

Figure 4-1. Monetized Health Co-benefits for each Option (Regional Compliance) of the Proposed EGU GHG Existing Source Guidelines in 2020 *

*The $PM_{2.5}$ graphs show the estimated $PM_{2.5}$ co-benefits at discount rates of 3% and 7% using effect coefficients derived from the Krewski et al. (2009) study and the Lepeule et al. (2012) study, as well as 12 effect coefficients derived from EPA's expert elicitation on PM mortality (Roman et al., 2008). The results shown are not the direct results from the studies or expert elicitation; rather, the estimates are based in part on the concentration-response functions provided in those studies. The ozone graphs show the estimated ozone co-benefits derived from six ozone mortality studies (i.e., Bell et al. (2004), Schwartz (2005), Huang et al. (2005), Bell et al. (2005), Levy et al. (2005), and Ito et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates. These estimates do not include climate benefits. The monetized co-benefits do not include climate benefits or reduced health effects from direct exposure to NO_2, SO_2, ecosystem effects, or visibility impairment. Results would be similar if the state compliance scenario was shown.

Low Health Co-benefits High Health Co-benefits

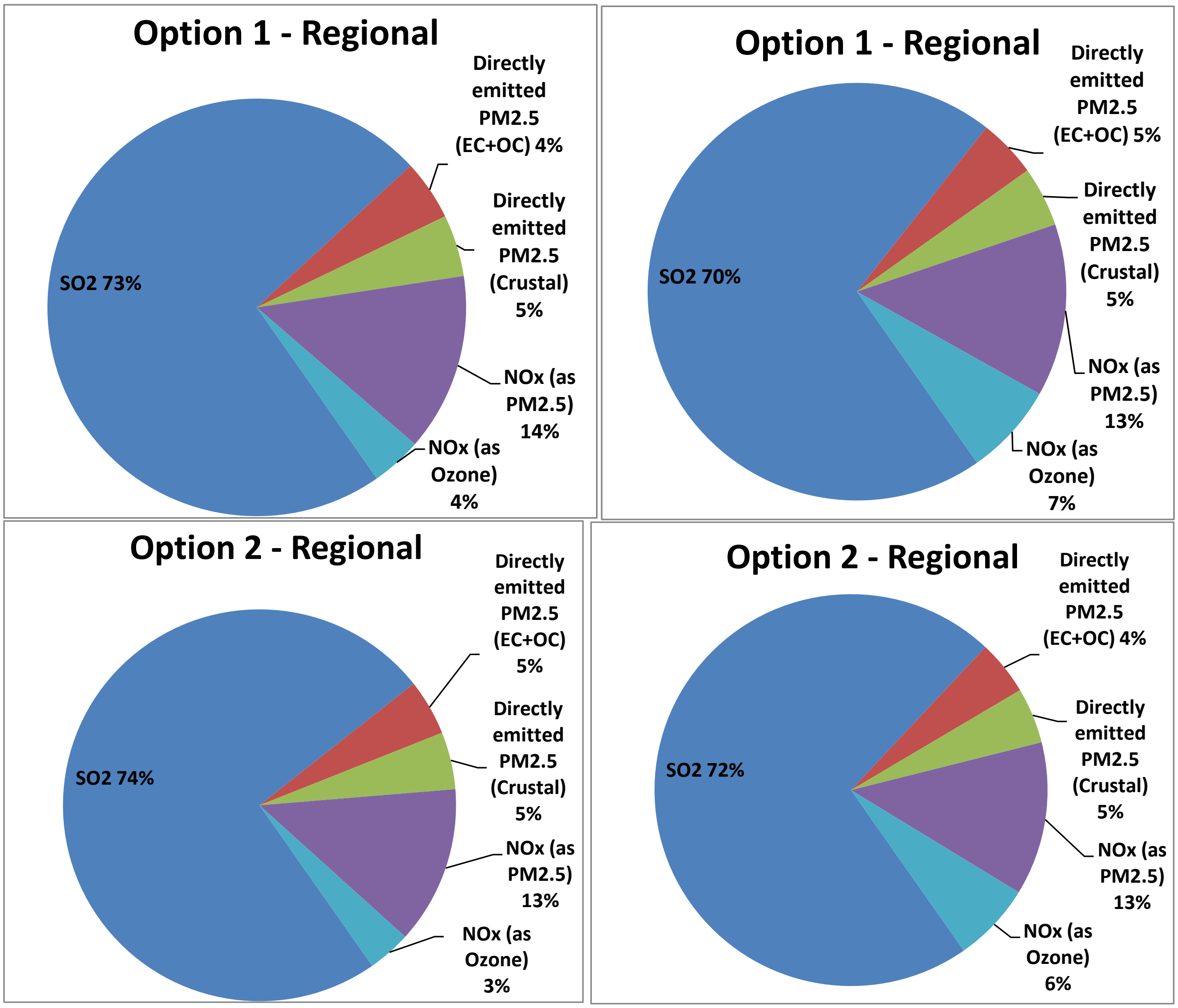

Figure 4-2. Breakdown of Monetized Health Co-benefits by Precursor Pollutant at a 3% Discount Rate for each Option (Regional Compliance) for Proposed EGU GHG Existing Source Guidelines in 2020*

* "Low Health Co-benefits" refers to the combined health co-benefits estimated using the Bell et al. (2004) mortality study for ozone with the Krewski et al. (2009) mortality study for $PM_{2.5}$. "High Health Co-benefits" refers to the combined health co-benefits estimated using the Levy et al. (2005) mortality study for ozone with the Lepeule et al. (2012) mortality study for $PM_{2.5}$. Results would be similar if the state compliance scenario was shown.

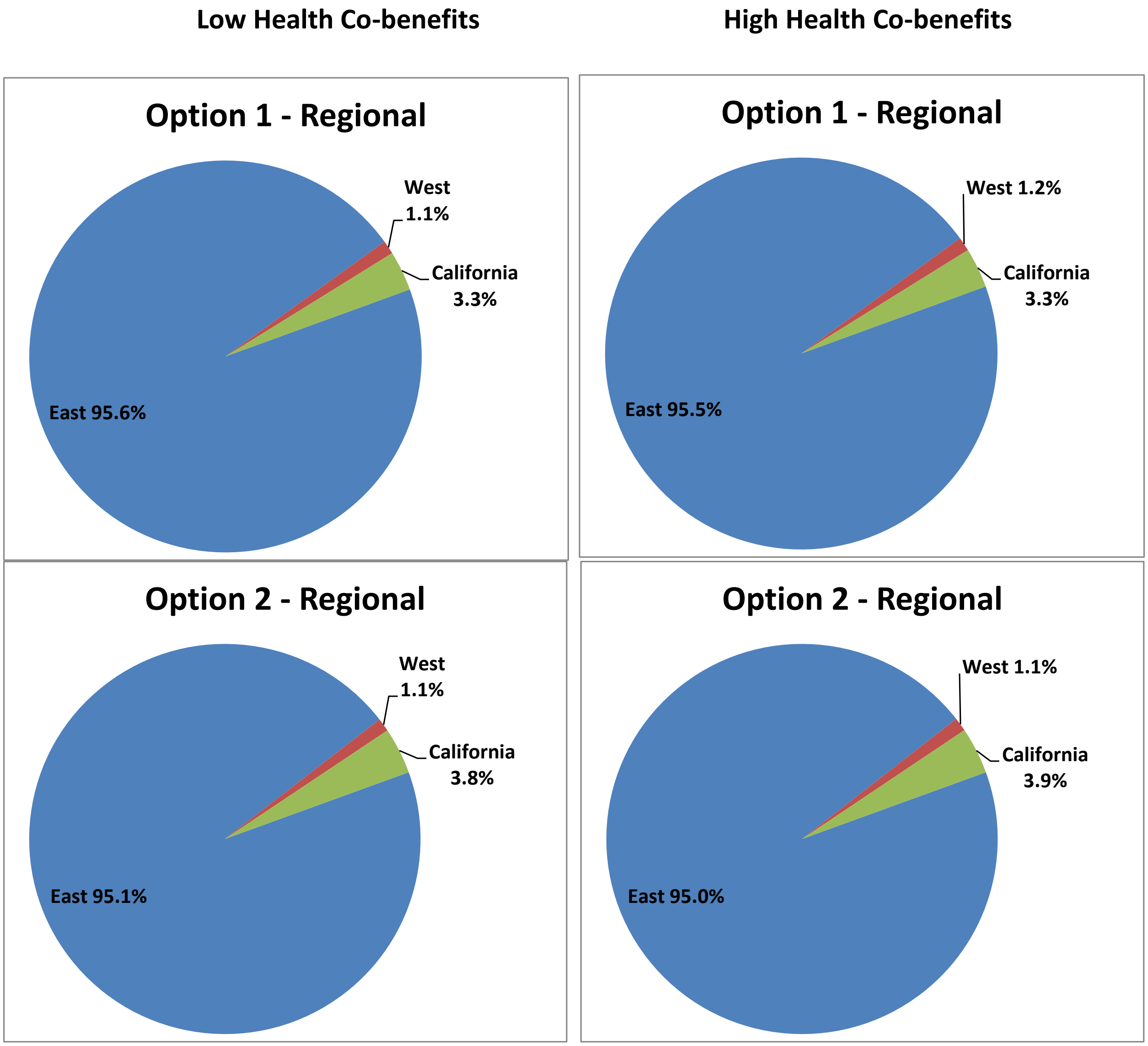

Figure 4-3. Breakdown of Monetized Health Co-Benefits by Region at a 3% Discount Rate for each Option (Regional compliance) for Proposed EGU GHG Existing Source Guidelines in 2020*

* "Low Health Co-benefits" refers to the combined health co-benefits estimated using the Bell et al. (2004) mortality study for ozone with the Krewski et al. (2009) mortality study for $PM_{2.5}$. "High Health Co-benefits" refers to the combined health co-benefits estimated using the Levy et al. (2005) mortality study for ozone with the Lepeule et al. (2012) mortality study for $PM_{2.5}$. Results would be similar if the state compliance scenario was shown.

4.3.6 Characterization of Uncertainty in the Estimated Health Co-benefits

In any complex analysis using estimated parameters and inputs from numerous models, there are likely to be many sources of uncertainty. This analysis is no exception. This analysis includes many data sources as inputs, including emission 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 co-benefits, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). Each of these inputs may be uncertain and would affect the estimate of co-benefits. 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 co-benefits in each analysis year should be viewed as representative of the general magnitude of co-benefits of the illustrative compliance scenarios, rather than the actual co-benefits anticipated from implementing the proposed guidelines.

This RIA does not include the type of detailed uncertainty assessment found in the PM NAAQS RIA (U.S. EPA, 2012a) or the Ozone NAAQS RIA (U.S. EPA, 2008b) because we lack the necessary air quality modeling input and/or monitoring data to run the benefits model. However, the results of the quantitative and qualitative uncertainty analyses presented in the PM NAAQS RIA and Ozone NAAQS RIAs can provide some information regarding the uncertainty inherent in the estimated co-benefits results presented in this analysis. For example, sensitivity analyses conducted for the PM NAAQS RIA indicate that alternate cessation lag assumptions could change the estimated $PM_{2.5}$-related mortality co-benefits discounted at 3 percent by between 10 percent and –27 percent and that alternate income growth adjustments could change the $PM_{2.5}$-related mortality co-benefits by between 33 percent and −14 percent. Although we generally do not calculate confidence intervals for benefit-per-ton estimates and they can provide an incomplete picture about the overall uncertainty in the benefits estimates, the PM NAAQS RIA can provide an indication of the random sampling error in the health impact and economic valuation functions using Monte Carlo methods. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski et al. (2009) and Lepeule et al. (2012). The 95th percentile confidence interval for the health impact function alone ranges from approximately ±30 percent for mortality incidence based on Krewski et al. (2009) and ±46 percent based on Lepeule et al. (2012).

Unlike RIAs for which EPA conducts air quality modeling, we do not have information on the specific location of the air quality changes associated with the proposed guidelines. As such, it is not feasible to estimate the proportion of co-benefits occurring in different locations, such as designated nonattainment areas. Instead, we applied benefit-per-ton estimates, which reflect specific geographic patterns of emissions reductions and specific air quality and benefits modeling assumptions. For example, these estimates may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors that might lead to an over-estimate or under-estimate of the actual co-benefits of controlling PM and ozone precursors. Use of these benefit-per-ton values to estimate co-benefits may lead to higher or lower benefit estimates than if co-benefits were calculated based on direct air quality modeling. Great care should be taken in applying these estimates to emission reductions occurring in any specific location, as these are all based on broad emission reduction scenarios and therefore represent average benefits-per-ton over the entire region. The benefit-per-ton for emission reductions in specific locations may be very different than the estimates presented here. To the extent that the geographic distribution of the emissions reductions achieved by implementing the proposed guidelines is different than the emissions in the sector modeling, the co-benefits may be underestimated or overestimated. For more information regarding the limitations of benefit-per-ton estimates derived from the sector modeling, see the TSD describing the calculation of the national benefit-per-ton estimates (U.S. EPA, 2013a) and Fann et al. (2012). In addition, the appendix to this chapter provides additional uncertainty information regarding the benefit-per-ton estimates applied in this RIA, including an evaluation of the similarities and differences in the spatial distribution of EGU emissions in the sector modeling and the IPM base case discussed in Chapter 3 of this RIA.

Our estimate of the total monetized co-benefits is based on EPA's interpretation of the best available scientific literature and methods and supported by the SAB-HES and the National Academies of Science (NRC, 2002). Below are key assumptions underlying the estimates for $PM_{2.5}$-related premature mortality, which accounts for 98 percent of the monetized $PM_{2.5}$ health co-benefits.

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

2. We assume that the health impact function for fine particles is log-linear without a threshold in this analysis. Thus, the estimates include health co-benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both areas that do not meet the fine particle standard and those areas that are in attainment, down to the lowest modeled concentrations.

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

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies. Concentration benchmark analyses (e.g., lowest measured level [LML], one standard deviation below the mean of the air quality data in the study, etc.) allow readers to determine the portion of population exposed to annual mean $PM_{2.5}$ levels at or above different concentrations, which provides some insight into the level of uncertainty in the estimated $PM_{2.5}$ mortality benefits. In this analysis, we apply two concentration benchmark approaches (LML and one standard deviation below the mean) that have been incorporated into recent RIAs and EPA's Policy Assessment for Particulate Matter (U.S. EPA, 2011d). There are uncertainties inherent in identifying any particular point at which our confidence in reported associations becomes appreciably less, and the scientific evidence provides no clear dividing line. However, the EPA does not view these concentration benchmarks as a concentration threshold below which we would not quantify health co-benefits of air quality improvements.[99] Rather, the co-benefits estimates reported in this RIA are the best estimates because they reflect the full range of air quality concentrations associated with the emission reduction strategies. The PM ISA concluded that the scientific evidence collectively is sufficient to conclude that the

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

relationship between long-term $PM_{2.5}$ exposures and mortality is causal and that overall the studies support the use of a no-threshold log-linear model to estimate PM-related long-term mortality (U.S. EPA, 2009b).

For this analysis, policy-specific air quality data is not available, and the compliance strategies are illustrative of what states may choose to do. For this RIA, we are unable to estimate the percentage of premature mortality associated with the emission reductions at each $PM_{2.5}$ concentration, as we have done for previous rules with air quality modeling (e.g., U.S. EPA, 2011b, 2012a). However, we believe that it is still important to characterize the distribution of exposure to baseline concentrations. As a surrogate measure of mortality impacts, we provide the percentage of the population exposed at each $PM_{2.5}$ concentration in the baseline of the source apportionment modeling used to calculate the benefit-per-ton estimates for this sector using 12 km grid cells across the contiguous U.S.[100] It is important to note that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates population and change in air quality. In other words, the percentage of the population exposed to air pollution below the LML is not the same as the percentage of the population experiencing health impacts as a result of a specific emission reduction policy. The most important aspect, which we are unable to quantify without rule-specific air quality modeling, is the shift in exposure anticipated by implementing the proposed guidelines. Therefore, caution is warranted when interpreting the LML assessment in this RIA because these results are not consistent with results from RIAs that had air quality modeling.

Table 4-19 provides the percentage of the population exposed above and below two concentration benchmarks (i.e., LML and one standard deviation below the mean) in the modeled baseline for the sector modeling. Figure 4-4 shows a bar chart of the percentage of the population exposed to various air quality levels in the baseline, and Figure 4-5 shows a cumulative distribution function of the same data. Both figures identify the LML for each of the major cohort studies.

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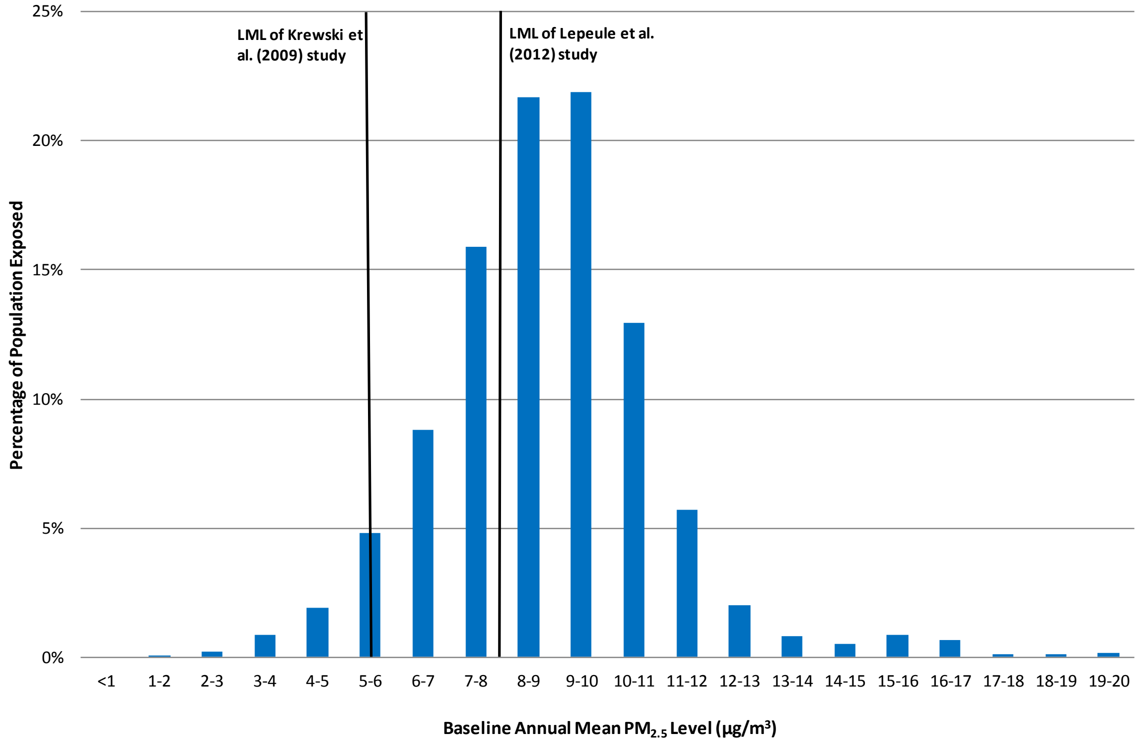
[100] As noted above, the modeling used to generate the benefit-per-ton estimates does not reflect emission reductions anticipated from MATS rule. Therefore, the baseline $PM_{2.5}$ concentrations in the LML assessment are higher than would be expected if MATS was reflected.

Table 4-19. Population Exposure in the Baseline Sector Modeling (used to generate the benefit-per-ton estimates) Above and Below Various Concentrations Benchmarks in the Underlying Epidemiology Studies *

Epidemiology Study	Below 1 Standard Deviation. Below AQ Mean	At or Above 1 Standard Deviation Below AQ Mean	Below LML	At or Above LML
Krewski et al. (2009)	89%	11%	7%	93%
Lepeule et al. (2012)	N/A	N/A	23%	67%

*One standard deviation below the mean is equivalent to the middle of the range between the 10th and 25th percentile. For Krewski, the LML is 5.8 μg/m^3 and one standard deviation below the mean is 11.0 μg/m^3. For Lepeule et al., the LML is 8 μg/m^3 and we do not have the data for one standard deviation below the mean. It is important to emphasize that although we have lower levels of confidence in levels below the LML for each study, the scientific evidence does not support the existence of a level below which health effects from exposure to $PM_{2.5}$ do not occur.



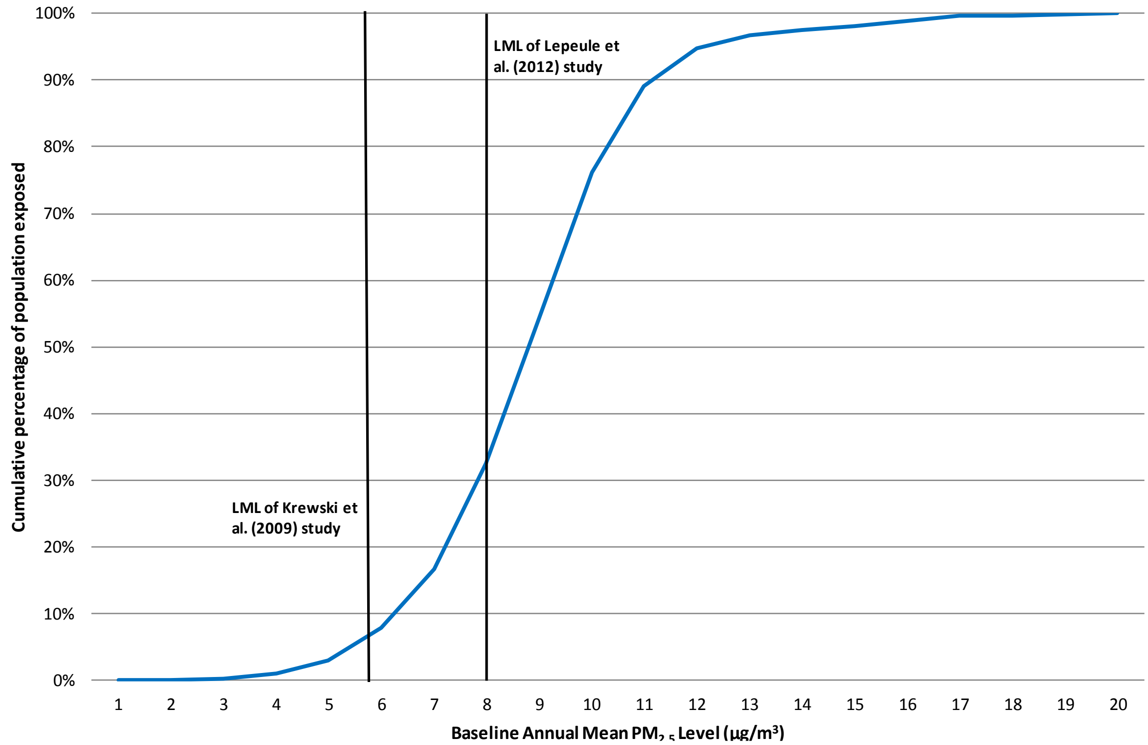
Among the populations exposed to $PM_{2.5}$ in the baseline:

93% are exposed to $PM_{2.5}$ levels at or above the LML of the Krewski et al. (2009) study

67% are exposed to $PM_{2.5}$ levels at or above the LML of the Lepeule et al. (2012) study

Figure 4-4. Percentage of Adult Population (age 30+) by Annual Mean $PM_{2.5}$ Exposure in the Baseline Sector Modeling (used to generate the benefit-per-ton estimates)*

* This graph shows the population exposure in the modeling baseline used to generate the benefit-per-ton estimates. Similar graphs for analyses with air quality modeling show premature mortality impacts at each $PM_{2.5}$ concentration. Therefore, caution is warranted when interpreting this graph because it is not derived in a manner consistent with similar graphs from RIAs that had been based on air quality modeling (e.g., MATS).



Among the populations exposed to $PM_{2.5}$ in the baseline:

93% are exposed to $PM_{2.5}$ levels at or above the LML of the Krewski et al. (2009) study

67% are exposed to $PM_{2.5}$ levels at or above the LML of the Lepeule et al. (2012) study

Figure 4-5. Cumulative Distribution of Adult Population (age 30+) by Annual Mean $PM_{2.5}$ Exposure in the Baseline Sector Modeling (used to generate the benefit-per-ton estimates)*

* This graph shows the population exposure in the modeling baseline used to generate the benefit-per-ton estimates. Similar graphs for analyses with air quality modeling show premature mortality impacts at each $PM_{2.5}$ concentration. Therefore, caution is warranted when interpreting this graph because it is not derived in a manner consistent with similar graphs from RIAs that had based on air quality modeling (e.g., MATS).

4.4 Combined Climate Benefits and Health Co-benefits Estimates

In this analysis, we were able to monetize the estimated co-benefits associated with the decreased emissions of CO_2 and reduced exposure to $PM_{2.5}$ and ozone, but we were unable to monetize the co-benefits associated with reducing exposure to mercury, hydrogen chloride, carbon monoxide, SO_2, and NO_2, as well as ecosystem effects and visibility impairment. Specifically, we estimated the combined climate benefits at discount rates of 5 percent, 3 percent, 2.5 percent, and 3 percent (95^{th} percentile) (as estimated by the interagency working group), and health co-benefits at discount rates of 3 percent and 7 percent (as recommended by

EPA's *Guidelines for Preparing Economic Analyses* (U.S. EPA, 2010e) and OMB's *Circular A-4* [OMB, 2003]).

Different discount rates are applied to SCC than to the health co-benefit estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. Moreover, several rates are applied to SCC because the literature shows that it is sensitive to assumptions about discount rate and because no consensus exists on the appropriate rate to use in an intergenerational context. The SCC interagency group centered its attention on the 3 percent discount rate but emphasized the importance of considering all four SCC estimates.[101] The EPA has evaluated the range of potential impacts by combining all SCC values with health co-benefits values at the 3 percent and 7 percent discount rates. To be consistent with concepts of intergenerational discounting, values for health benefits, which occur within a generation, would only be combined with SCC values using a lower discount rate (e.g., the 7 percent health benefit estimates would be combined with 5 percent or lower SCC values, but the 3 percent health benefit would not be combined with the 5 percent SCC value). While the 5 percent SCC and 3 percent health benefit estimate falls within the range of values we analyze, this individual estimate should not be used independently in an analysis, as it represents a combination of discount rates that is unlikely to occur. Combining the 3 percent SCC values with the 3 percent health benefit values assumes that there is no difference in discount rates between intragenerational and intergenerational impacts.

Tables 4-20 through 4-22 provide the combined climate and health benefits for each option evaluated for 2020, 2025, and 2030. Figure 4-6 shows the breakdown of the monetized benefits by pollutant for each option evaluated in 2020 as an illustrative analysis year using a 3 percent discount rate.

[101] See the 2010 SCC TSD. Docket ID EPA-HQ-OAR-2009-0472-114577 or http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf for details.

Table 4-20. Combined Climate Benefits and Health Co-Benefits for Proposed EGU GHG Existing Source Guidelines in 2020 (billions of 2011$)*

SCC Discount Rate	Climate Benefits Only	Climate Benefits plus Health Co-Benefits (Discount Rate Applied to Health Co-Benefits)					
		3%			7%		
Option 1 - state	383	million metric tonnes CO_2					
5%	$4.9	$22	to	$45	$20	to	$41
3%	$18	$35	to	$57	$33	to	$54
2.5%	$26	$43	to	$66	$42	to	$62
3% (95th percentile)	$52	$69	to	$92	$68	to	$88
Option 1 - regional	371	million metric tonnes CO_2					
5%	$4.7	$21	to	$42	$19	to	$39
3%	$17	$33	to	$54	$32	to	$51
2.5%	$25	$41	to	$63	$40	to	$59
3% (95th percentile)	$51	$67	to	$88	$65	to	$85
Option 2 - state	295	million metric tonnes CO_2					
5%	$3.8	$17	to	$35	$16	to	$32
3%	$14	$27	to	$45	$26	to	$42
2.5%	$20	$34	to	$52	$32	to	$49
3% (95th percentile)	$40	$54	to	$72	$53	to	$69
Option 2 - regional	283	million metric tonnes CO_2					
5%	$3.6	$17	to	$34	$16	to	$32
3%	$13	$26	to	$44	$25	to	$41
2.5%	$19	$33	to	$50	$31	to	$47
3% (95th percentile)	$39	$52	to	$70	$51	to	$67

*All estimates are rounded to two significant figures. Climate benefits are based on reductions in CO_2 emissions. Co-benefits are based on regional benefit-per-ton estimates. Co-benefits for ozone are based on ozone season NOx emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski et al. (2009) with Bell et al. (2004) to Lepeule et al. (2012) with Levy et al. (2005)). The monetized health co-benefits do not include reduced health effects from direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment.

Table 4-21. Combined Climate Benefits and Health Co-Benefits for Proposed EGU GHG Existing Source Guidelines in 2025 (billions of 2011$)*

SCC Discount Rate	Climate Benefits Only	Climate Benefits plus Health Co-Benefits (Discount Rate Applied to Health Co-Benefits)					
		3%			7%		
Option 1 - state	506	million metric tonnes CO_2					
5%	$7.6	$31	to	$62	$29	to	$57
3%	$25	$49	to	$80	$46	to	$75
2.5%	$37	$61	to	$92	$58	to	$87
3% (95th percentile)	$77	$100	to	$130	$98	to	$130
Option 1 - regional	501	million metric tonnes CO_2					
5%	$7.5	$30	to	$61	$28	to	$56
3%	$25	$48	to	$78	$46	to	$74
2.5%	$37	$60	to	$90	$57	to	$85
3% (95th percentile)	$76	$99	to	$130	$97	to	$120
Option 2 - state	376	million metric tonnes CO_2					
5%	$5.6	$23	to	$47	$22	to	$43
3%	$19	$36	to	$60	$35	to	$56
2.5%	$28	$45	to	$69	$44	to	$65
3% (95th percentile)	$57	$75	to	$98	$73	to	$95
Option 2 - regional	368	million metric tonnes CO_2					
5%	$5.5	$23	to	$46	$21	to	$42
3%	$18	$36	to	$59	$34	to	$55
2.5%	$27	$44	to	$67	$43	to	$64
3% (95th percentile)	$56	$73	to	$96	$72	to	$93

*All estimates are rounded to two significant figures. Climate benefits are based on reductions in CO_2 emissions. Co-benefits are based on regional benefit-per-ton estimates. Co-benefits for ozone are based on ozone season NOx emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski et al. (2009) with Bell et al. (2004) to Lepeule et al. (2012) with Levy et al. (2005)). It is important to note that the monetized health co-benefits do not include reduced health effects from direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment.

Table 4-22. Combined Climate Benefits and Health Co-Benefits for Proposed EGU GHG Existing Source Guidelines in 2030 (billions of 2011$)*

SCC Discount Rate	Climate Benefits Only	Climate Benefits plus Health Co-Benefits (Discount Rate Applied to Health Co-Benefits)					
		3%			7%		
Option 1 - state	555	million metric tonnes CO_2					
5%	$9.5	$36	to	$72	$34	to	$66
3%	$31	$57	to	$93	$55	to	$87
2.5%	$44	$71	to	$110	$69	to	$100
3% (95th percentile)	$94	$120	to	$160	$120	to	$150
Option 1 - regional	545	million metric tonnes CO_2					
5%	$9.3	$35	to	$68	$32	to	$63
3%	$30	$55	to	$89	$53	to	$84
2.5%	$44	$69	to	$100	$66	to	$97
3% (95th percentile)	$92	$120	to	$150	$120	to	$150

*All estimates are rounded to two significant figures. Climate benefits are based on reductions in CO_2 emissions. Co-benefits are based on regional benefit-per-ton estimates. Co-benefits for ozone are based on ozone season NOx emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski et al. (2009) with Bell et al. (2004) to Lepeule et al. (2012) with Levy et al. (2005)). It is important to note that the monetized health co-benefits do not include reduced health effects from direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment.

Low Health Co-benefits **High Health Co-benefits**

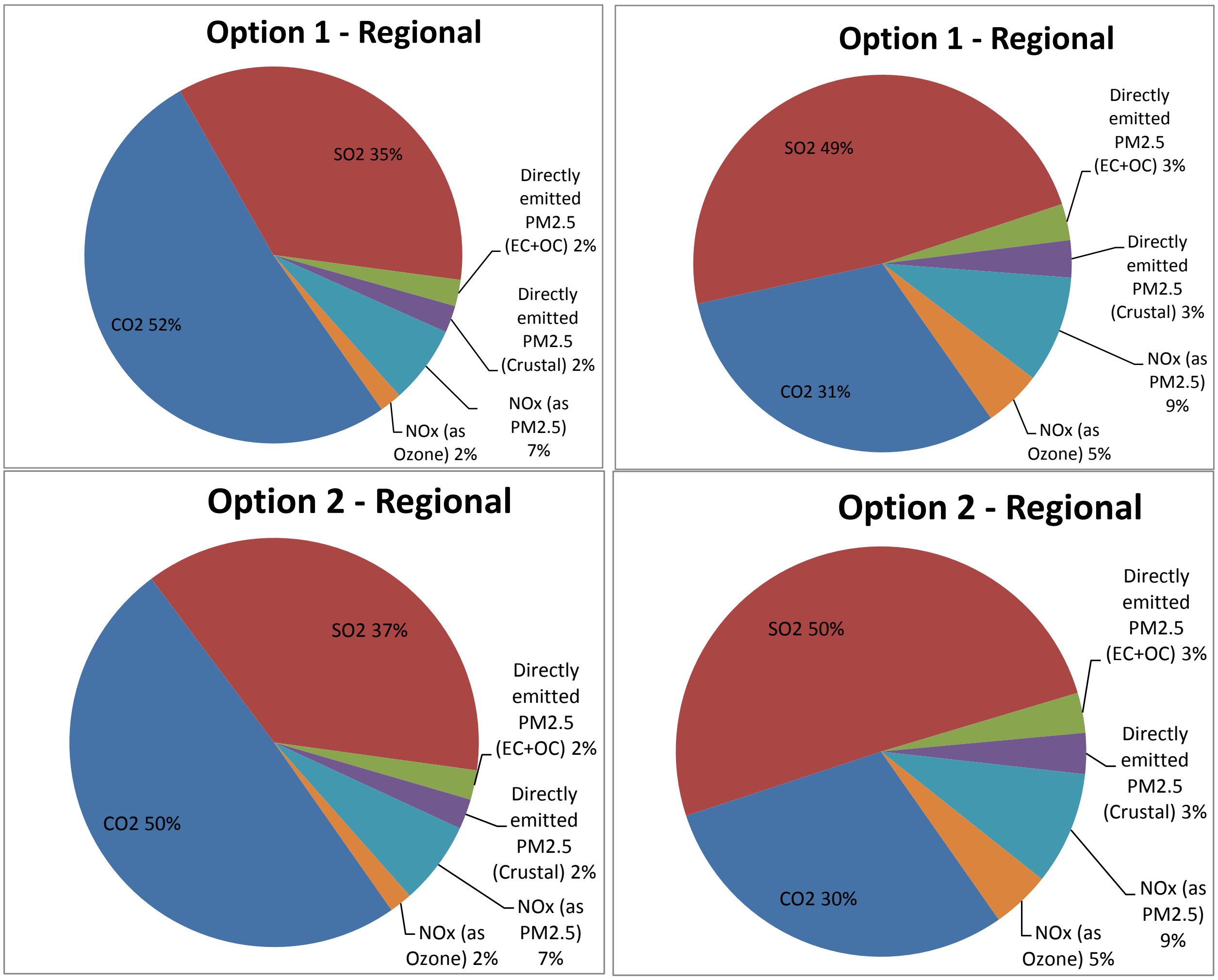


Figure 4-6. Breakdown of Combined Monetized Climate and Health Co-benefits of Proposed EGU GHG Existing Source Guidelines in 2020 by Option (Regional Compliance) and Pollutant (3% discount rate)*

* "Low Health Co-benefits" refers to the combined health co-benefits estimated using the Bell et al. (2004) mortality study for ozone with the Krewski et al. (2009) mortality study for $PM_{2.5}$. "High Health Co-benefits" refers to the combined health co-benefits estimated using the Levy et al. (2005) mortality study for ozone with the Lepeule et al. (2012) mortality study for $PM_{2.5}$. Results would be similar if the state compliance scenario was shown.

4.5 Unquantified Co-benefits

The monetized co-benefits estimated in this RIA only reflect a subset of co-benefits attributable to the health effect reductions associated with ambient fine particles and ozone. Data, time, and resource limitations prevented EPA from quantifying the impacts to, or monetizing the co-benefits from several important benefit categories, including co-benefits associated with exposure to several HAP (including mercury and hydrogen chloride) SO_2 and NO_2, as well as ecosystem effects, and visibility impairment due to the absence of air quality modeling data for these pollutants in this analysis. This does not imply that there are no co-benefits associated with these emission reductions. In this section, we provide a qualitative description of these benefits, which are listed in Table 4-23.

Table 4-23. Unquantified Health and Welfare Co-benefits Categories

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Human Health				
Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions (all ages)	—	—	NO_2 ISA[1]
	Chronic lung disease hospital admissions (age > 65)	—	—	NO_2 ISA[1]
	Respiratory emergency department visits (all ages)	—	—	NO_2 ISA[1]
	Asthma exacerbation (asthmatics age 4–18)	—	—	NO_2 ISA[1]
	Acute respiratory symptoms (age 7–14)	—	—	NO_2 ISA[1]
	Premature mortality	—	—	NO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO_2 ISA[2,3]
Reduced incidence of morbidity from exposure to SO_2	Respiratory hospital admissions (age > 65)	—	—	SO_2 ISA[1]
	Asthma emergency department visits (all ages)	—	—	SO_2 ISA[1]
	Asthma exacerbation (asthmatics age 4–12)	—	—	SO_2 ISA[1]
	Acute respiratory symptoms (age 7–14)	—	—	SO_2 ISA[1]
	Premature mortality	—	—	SO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	SO_2 ISA[1,2]
Reduced incidence of morbidity from exposure to CO	Cardiovascular effects	—	—	CO ISA [1,2]
	Respiratory effects	—	—	CO ISA [1,2,3]
	Central nervous system effects	—	—	CO ISA [1,2,3]
	Premature mortality	—	—	CO ISA [1,2,3]
Reduced incidence of morbidity from exposure to methylmercury	Neurologic effects—IQ loss	—	—	IRIS; NRC, 2000[1]
	Other neurologic effects (e.g., developmental delays, memory, behavior)	—	—	IRIS; NRC, 2000[2]
	Cardiovascular effects	—	—	IRIS; NRC, 2000[2,3]
	Genotoxic, immunologic, and other toxic effects	—	—	IRIS; NRC, 2000[2,3]
Reduced incidence of morbidity from exposure to HAP	Effects associated with exposure to hydrogen chloride	—	—	ATSDR, IRIS[1,2]
Improved Environment				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[1]
	Visibility in residential areas	—	—	PM ISA[1]

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Reduced effects on materials	Household soiling	—	—	PM ISA[1,2]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[2]
Reduced effects from PM deposition (metals and organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[2]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[1]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[1]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[1]
	Damage to urban ornamental plants	—	—	Ozone ISA[2]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[1]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[2]
	Other non-use effects			Ozone ISA[2]
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[2]
Reduced effects from acid deposition	Recreational fishing	—	—	NO_x SO_x ISA[1]
	Tree mortality and decline	—	—	NO_x SO_x ISA[2]
	Commercial fishing and forestry effects	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO_x SO_x ISA[2]
Reduced effects from nutrient enrichment	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Coastal eutrophication	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NO_x SO_x ISA[2]
Reduced vegetation effects from ambient exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NO_x SO_x ISA[2]
	Injury to vegetation from NO_x exposure	—	—	NO_x SO_x ISA[2]
Reduced ecosystem effects from exposure to methylmercury	Effects on fish, birds, and mammals (e.g., reproductive effects)	—	—	Mercury Study RTC[2]
	Commercial, subsistence and recreational fishing	—	—	Mercury Study RTC[1]

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

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

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

4.5.1 HAP Co-benefits

Due to methodology and resource limitations, we were unable to estimate the co-benefits associated with reducing emissions of the hazardous air pollutants in this analysis. EPA's SAB-HES concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAPs) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008). In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAP. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn et al., 2011).

Chapter 4 of the MATS RIA (U.S. EPA, 2011b) describes the health effects associated with HAP emitted by EGUs. Below we describe the health effects associated with the two HAP for which we were able to quantify emission reductions for the proposed guidelines: mercury and hydrogen chloride. Using the IPM modeling described in Chapter 3 of this RIA, we estimate that the illustrative compliance scenarios for the proposed guidelines would reduce mercury emissions by up to 2.1 tons and hydrogen chloride by up to 590 tons by 2030. These HAP emission reductions are beyond those achieved by MATS.

4.5.1.1 Mercury

Mercury in the environment is transformed into a more toxic form, methylmercury (MeHg). Because Hg is a persistent pollutant, MeHg accumulates in the food chain, especially the tissue of fish. When people consume these fish, they consume MeHg. In 2000, the NAS Study was issued which provides a thorough review of the effects of MeHg on human health (NRC, 2000).[102] Many of the peer-reviewed articles cited in this section are publications originally cited in the Mercury Study.[103] In addition, EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NRC in 2000.

In its review of the literature, the NAS found neurodevelopmental effects to be the most

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[102] National Research Council (NRC). 2000. *Toxicological Effects of Methylmercury*. Washington, DC: National Academies Press.

[103] U.S. Environmental Protection Agency (U.S. EPA). 1997. *Mercury Study Report to Congress*, EPA–HQ–OAR–2009–0234–3054. December. Available on the Internet at <http://www.epa.gov/hg/report.htm>.

sensitive and best documented endpoints and appropriate for establishing a reference dose (RfD) (NRC, 2000); in particular NAS supported the use of results from neurobehavioral or neuropsychological tests. The NAS report noted that studies in animals reported sensory effects as well as effects on brain development and memory functions and support the conclusions based on epidemiology studies. The NAS noted that their recommended endpoints for an RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: "The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school."

The NAS summarized data on cardiovascular effects available up to 2000. Based on these and other studies, the NRC concluded that "Although the data base is not as extensive for cardiovascular effects as it is for other end points (i.e., neurologic effects), the cardiovascular system appears to be a target for MeHg toxicity in humans and animals." The NRC also stated that "additional studies are needed to better characterize the effect of methylmercury exposure on blood pressure and cardiovascular function at various stages of life."

Additional cardiovascular studies have been published since 2000. EPA did not develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS concluded that evidence that human exposure to MeHg caused genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajós River region in Brazil (Amorim et al., 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes, as well as effects on chromosomes.[104] Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, and chronic MeHg exposures similar to and above those seen in the Faroes and Seychelles populations.

Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response (ATSDR, 1999), evidence for immunotoxic effects of MeHg is limited (NRC, 2000).[105]

Based on limited human and animal data, MeHg is classified as a "possible" human carcinogen by the International Agency for Research on Cancer (IARC, 1994)[106] and in IRIS (U.S. EPA, 2002).[107] The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg exposure and specific types of cancer incidence (e.g., acute leukemia and liver cancer) (NRC, 2000).

There is also some evidence of reproductive and renal toxicity in humans from MeHg exposure. However, overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on either studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

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[104] Amorim, M.I.M., D. Mergler, M.O. Bahia, H. Dubeau, D. Miranda, J. Lebel, R.R. Burbano, and M. Lucotte. 2000. Cytogenetic damage related to low levels of methyl mercury contamination in the Brazilian Amazon. An. Acad. Bras. Ciênc. 72(4): 497-507.

[105] Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological Profile for Mercury. U.S. Department of Health and Human Services, Public Health Service, Atlanta, GA.

[106] International Agency for Research on Cancer (IARC). 1994. IARC Monographs on the Evaluation of Carcinogenic Risks to Humans and their Supplements: Beryllium, Cadmium, Mercury, and Exposures in the Glass Manufacturing Industry. Vol. 58. Jalili, H.A., and A.H. Abbasi. 1961. Poisoning by ethyl mercury toluene sulphonanilide. Br. J. Indust. Med. 18(Oct.):303-308 (as cited in NRC, 2000).

[107] U.S. Environmental Protection Agency (EPA). 2002. Integrated Risk Information System (IRIS) on Methylmercury. National Center for Environmental Assessment. Office of Research and Development. Available at http://www.epa.gov/iris/subst/0073.htm.

4.5.1.2 Hydrogen Chloride

Hydrogen chloride (HCl) is a corrosive gas that can cause irritation of the mucous membranes of the nose, throat, and respiratory tract. Brief exposure to 35 ppm causes throat irritation, and levels of 50 to 100 ppm are barely tolerable for 1 hour.[108] The greatest impact is on the upper respiratory tract; exposure to high concentrations can rapidly lead to swelling and spasm of the throat and suffocation. Most seriously exposed persons have immediate onset of rapid breathing, blue coloring of the skin, and narrowing of the bronchioles. Exposure to HCl can lead to Reactive Airways Dysfunction Syndrome (RADS), a chemically, or irritant-induced type of asthma. Children may be more vulnerable to corrosive agents than adults because of the relatively smaller diameter of their airways. Children may also be more vulnerable to gas exposure because of increased minute ventilation per kg and failure to evacuate an area promptly when exposed. Hydrogen chloride has not been classified for carcinogenic effects.[109]

4.5.2 Additional NO_2 Health Co-Benefits

In addition to being a precursor to $PM_{2.5}$ and ozone, NOx emissions are also associated with a variety of adverse health effects associated with direct exposure. Unfortunately, we were unable to estimate the health co-benefits associated with reduced NO_2 exposure in this analysis. Therefore, this analysis only quantified and monetized the $PM_{2.5}$ and ozone co-benefits associated with the reductions in NO_2 emissions.

Following a comprehensive review of health evidence from epidemiologic and laboratory studies, the *Integrated Science Assessment for Oxides of Nitrogen —Health Criteria* (NOx ISA) (U.S. EPA, 2008c) concluded that there is a likely causal relationship between respiratory health effects and short-term exposure to NO_2. The NOx ISA concluded that the evidence "is sufficient to infer a likely causal relationship between short-term NO_2 exposure and adverse effects on the respiratory system." These epidemiologic and experimental studies encompass a number of

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[108] Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Hydrogen Chloride. Atlanta, GA: U.S. Department of Health and Human Services. Available at http://www.atsdr.cdc.gov/mmg/mmg.asp?id=758&tid=147#bookmark02.

[109] U.S. Environmental Protection Agency (U.S. EPA). 1995. "Integrated Risk Information System File of Hydrogen Chloride." Washington, DC: Research and Development, National Center for Environmental Assessment. This material is available at http://www.epa.gov/iris/subst/0396.htm.

endpoints including emergency department visits and hospitalizations, respiratory symptoms, airway hyperresponsiveness, airway inflammation, and lung function. The NOx ISA also concluded that the relationship between short-term NO_2 exposure and premature mortality was "suggestive but not sufficient to infer a causal relationship," because it is difficult to attribute the mortality risk effects to NO_2 alone. Although the NOx ISA stated that studies consistently reported a relationship between NO_2 exposure and mortality, the effect was generally smaller than that for other pollutants such as PM.

4.5.3 Additional SO_2 Health Co-Benefits

In addition to being a precursor to $PM_{2.5}$, SO_2 emissions are also associated with a variety of adverse health effects associated with direct exposure. Unfortunately, we were unable to estimate the health co-benefits associated with reduced SO_2 in this analysis because we do not have air quality modeling data available. Therefore, this analysis only quantifies and monetizes the $PM_{2.5}$ co-benefits associated with the reductions in SO_2 emissions.

Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the *Integrated Science Assessment for Oxides of Sulfur —Health Criteria* (SO_2 ISA) concluded that there is a causal relationship between respiratory health effects and short-term exposure to SO_2 (U.S. EPA, 2008a). The immediate effect of SO_2 on the respiratory system in humans is bronchoconstriction. Asthmatics are more sensitive to the effects of SO_2 likely resulting from preexisting inflammation associated with this disease. A clear concentration-response relationship has been demonstrated in laboratory studies following exposures to SO_2 at concentrations between 20 and 100 ppb, both in terms of increasing severity of effect and percentage of asthmatics adversely affected. Based on our review of this information, we identified four short-term morbidity endpoints that the SO_2 ISA identified as a "causal relationship": asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations. The differing evidence and associated strength of the evidence for these different effects is described in detail in the SO_2 ISA. The SO_2 ISA also concluded that the relationship between short-term SO_2 exposure and premature mortality was "suggestive of a causal relationship" because it is difficult to attribute the mortality risk effects to SO_2 alone. Although the SO_2 ISA stated that studies are generally consistent in reporting a relationship between SO_2 exposure and mortality, there was a lack of robustness of the observed associations to adjustment for pollutants. We did not quantify these co-benefits due to data constraints.

4.5.4 Additional NO_2 and SO_2 Welfare Co-Benefits

As described in the *Integrated Science Assessment for Oxides of Nitrogen and Sulfur — Ecological Criteria* (NOx ISA) (U.S. EPA, 2008d), SO_2 and NOx emissions also contribute to a variety of adverse welfare effects, including acidic deposition, visibility impairment, and nutrient enrichment. Deposition of nitrogen causes acidification, which can cause a loss of biodiversity of fishes, zooplankton, and macro invertebrates in aquatic ecosystems, as well as a decline in sensitive tree species, such as red spruce (Picea rubens) and sugar maple (Acer saccharum) in terrestrial ecosystems. In the northeastern U.S., the surface waters affected by acidification are a source of food for some recreational and subsistence fishermen and for other consumers and support several cultural services, including aesthetic and educational services and recreational fishing. Biological effects of acidification in terrestrial ecosystems are generally linked to aluminum toxicity, which can cause reduced root growth, which restricts the ability of the plant to take up water and nutrients. These direct effects can, in turn, increase the sensitivity of these plants to stresses, such as droughts, cold temperatures, insect pests, and disease leading to increased mortality of canopy trees. Terrestrial acidification affects several important ecological services, including declines in habitat for threatened and endangered species (cultural), declines in forest aesthetics (cultural), declines in forest productivity (provisioning), and increases in forest soil erosion and reductions in water retention (cultural and regulating). (U.S. EPA, 2008d)

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

4.5.5 Ozone Welfare Co-Benefits

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2013b). Sensitivity to ozone is highly variable across species, with over 65 plan species identified as “ozone-sensitive”, many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced crop yields, visible foliar injury, reduced plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), species composition shift, and changes in ecosystems and associated ecosystem services.

4.5.6 Carbon Monoxide Co-Benefits

CO in ambient air is formed primarily by the incomplete combustion of carbon-containing fuels and photochemical reactions in the atmosphere. The amount of CO emitted from these reactions, relative to carbon dioxide (CO_2), is sensitive to conditions in the combustion zone, such as fuel oxygen content, burn temperature, or mixing time. Upon inhalation, CO diffuses through the respiratory system to the blood, which can cause hypoxia (reduced oxygen availability). Carbon monoxide can elicit a broad range of effects in multiple tissues and organ systems that are dependent upon concentration and duration of exposure. The *Integrated Science Assessment for Carbon Monoxide* (U.S. EPA, 2010a) concluded that short-term exposure to CO is “likely to have a causal relationship” with cardiovascular morbidity, particularly in individuals with coronary heart disease. Epidemiologic studies associate short-term CO exposure with increased risk of emergency department visits and hospital admissions. Coronary heart disease includes those who have angina pectoris (cardiac chest pain), as well as those who have experienced a heart attack. Other subpopulations potentially at risk include individuals with diseases such as chronic obstructive pulmonary disease (COPD), anemia, or diabetes, and individuals in very early or late life stages, such as older adults or the developing young. The evidence is suggestive of a causal relationship between short-term exposure to CO and respiratory morbidity and mortality. The evidence is also suggestive of a causal relationship for birth outcomes and developmental effects following long-term exposure to CO, and for central nervous system effects linked to short- and long-term exposure to CO.

4.5.7 Visibility Impairment Co-Benefits

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

4.6 References

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APPENDIX 4A: GENERATING REGIONAL BENEFIT-PER-TON ESTIMATES FOR ELECTRIC GENERATING UNITS

The purpose of this appendix is to provide additional detail regarding the generation of the benefit-per-ton estimates applied in Chapter 4 of this Regulatory Impact Analysis (RIA). Specifically, this appendix describes the methods for generating benefit-per-ton estimates by region for $PM_{2.5}$ and ozone precursors emitted by the electrical generating unit (EGU) sector.

4A.1 Overview of Benefit-per-Ton Estimates

As described in the *Technical Support Document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors* (U.S. EPA, 2013a) (hereafter "BPT TSD"), the procedure for calculating average benefit-per-ton coefficients generally follows three steps, shown graphically in Figure 4A-1. As an example, in order to calculate national average benefit-per-ton estimates for each ambient $PM_{2.5}$ precursor emitted from EGU sources, we:

1. Use air quality modeling to predict ambient concentrations of primary $PM_{2.5}$, nitrate and sulfate across the contiguous U.S. that are attributable to the EGU sector.

2. Estimate the health impacts, and the economic value of these impacts, associated with the attributable ambient concentrations of primary $PM_{2.5}$, sulfate and nitrate $PM_{2.5}$ using the environmental Benefits Mapping and Analysis Program (BenMAP v4.0.66)[110] (Abt Associates, Inc, 2012).

3. Divide the $PM_{2.5}$-related health impacts attributable to each type of $PM_{2.5}$, and the monetary value of these impacts, by the level of associated precursor emissions. That is, primary $PM_{2.5}$ benefits are divided by direct $PM_{2.5}$ emissions, sulfate benefits are divided by SO_2 emissions, and nitrate benefits are divided by NOx emissions.

[110] In this stage we estimate the $PM_{2.5}$-related impacts associated with changes in directly emitted $PM_{2.5}$, nitrate and sulfate separately, so that we may ultimately calculate the benefit-per-ton reduced of the corresponding $PM_{2.5}$ precursor, or directly emitted $PM_{2.5}$, in step 3. When estimating these impacts we apply effect coefficients that relate changes in total $PM_{2.5}$ mass to the risk of adverse health outcomes; we do not apply effect coefficients that are differentiated by $PM_{2.5}$ specie.

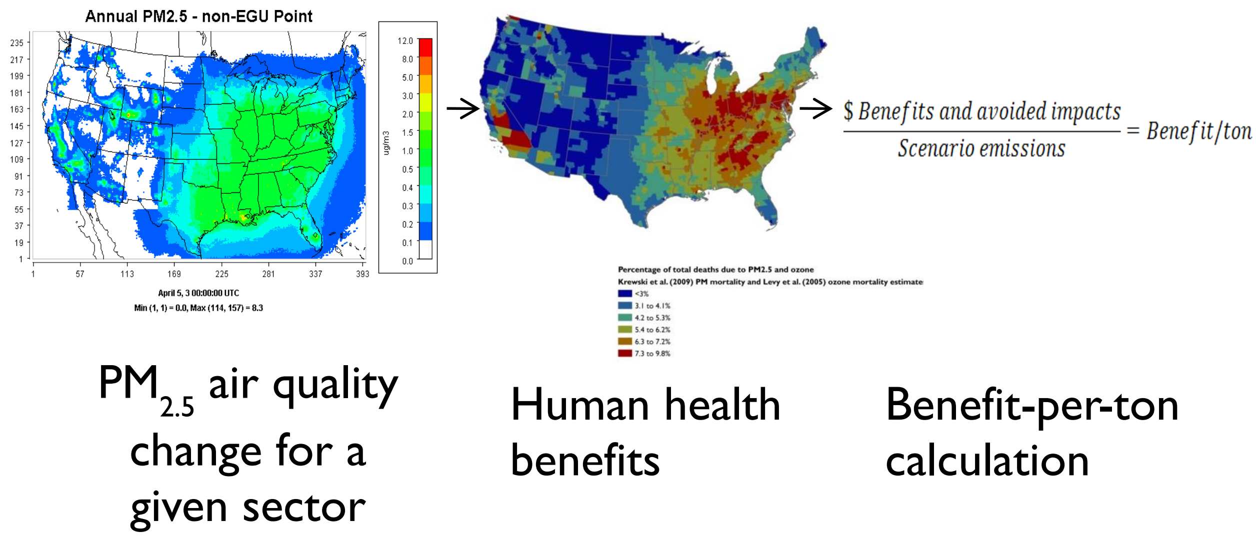

Figure 4A-1. Conceptual Overview of Benefit-per-Ton Calculation

4A.2 Underlying Source Apportionment Air Quality Modeling

EPA performed a national-scale air quality modeling analysis using the Comprehensive Air Quality Model with Extensions (CAMx) model[111] to estimate $PM_{2.5}$ and ozone concentrations attributable to 17 industrial sectors, including EGUs. In this section, we provide a short summary of the air quality modeling used to generate these benefit-per-ton estimates. Readers interested in a full discussion of the air quality modeling may consult the *Air Quality Modeling Technical Support Document: Source Sector Assessments* (U.S. EPA, 2011a). The source apportionment modeling is also discussed in Fann, Baker and Fulcher (2012).

CAMx simulates the numerous physical and chemical processes involved in the formation, transport, and destruction of ozone, particulate matter and air toxics. Emissions of precursor species are injected into the model where they react to form secondary species such as ozone and then transport around the modeling domain before ultimately being removed by

[111] Environ International Corporation. 2010. Comprehensive Air Quality Model with Extensions, Version 5.3. User's Guide. Novato, CA. December. Available at <http://www.camx.com>.

deposition or chemical reaction. Source apportionment techniques track the formation and transport of ozone and PM from specific emissions sources and calculate the contribution of sources and precursors to ozone and $PM_{2.5}$ at individual receptor locations. In contrast to "zero-out" modeling techniques, the tracking of emissions and resulting pollution in source apportionment modeling does not affect the transport, chemical transformation, or atmospheric chemical relationships within the modeling. More details on the implementation of source apportionment in CAMx can be found in the CAMx user's guide.

The modeling analyses were performed for a domain covering the continental U.S. This domain has a parent horizontal grid of 36 km with two finer-scale 12 km grids over the eastern and western U.S. The base year of data used to construct the modeling platform includes emissions and meteorology for 2005. Specifically, the starting point for the emission projections in this modeling was the 2005 v4.3 emissions platform (U.S. EPA, 2005). EGU emission estimates for 2016 are from the Integrated Planning Model (IPM), and the projections include emission reductions related to the NOx State Implementation Plan Call (U.S. EPA, 1998) and the proposed Transport Rule (U.S. EPA, 2010c).[112]

4A.3 Regional $PM_{2.5}$ Benefit-per-Ton Estimates for EGUs

The approach for generating regional benefit-per-ton estimates for $PM_{2.5}$ from EGU emissions is a small modification of the approach described above from the BPT TSD. The regional benefit-per-ton estimates reflect the ambient $PM_{2.5}$ attributable to the EGU sector in the source apportionment modeling ("sector modeling") from Fann, Baker, and Fulcher (2012), as illustrated in Figures 4A-2 and 4A-3 for 2016. After estimating the $PM_{2.5}$ benefits for each of the analysis years applied in this RIA (i.e., 2020, 2025, and 2030), we aggregated the benefits results regionally (i.e., East, West, and California) rather than nationally, as shown in Figure 4A-4.[113] Due to the low emissions of SO_2, NO_X, and directly emitted particles from EGUs in California

[112] The 2016 air quality modeling simulations underlying the benefit-per-ton estimates do not reflect emission reductions anticipated from the EGU sector as a result of the recently promulgated MATS rule, and so are likely to overstate the total $PM_{2.5}$ from this sector. (Fann, Fulcher, and Baker [2013]). The EGU contribution on a per-ton basis would be similar. Because the emission reductions in this RIA are calculated from an IPM base case that includes MATS (see Chapter 3), there is no double-counting concern with the resulting co-benefits estimates.

[113] This aggregation is identified as the shapefile "Report Regions" in BenMAP's grid definitions.

and the high population density, we separated out California in order not to bias the benefit-per-ton estimates for the rest of the Western U.S. In order to calculate the benefit-per-ton estimates, we divided the regional benefits estimates by the corresponding emissions, as shown in Table 4A-1. Lastly, we adjusted the benefit-per-ton estimates for a currency year of 2011$.[114]

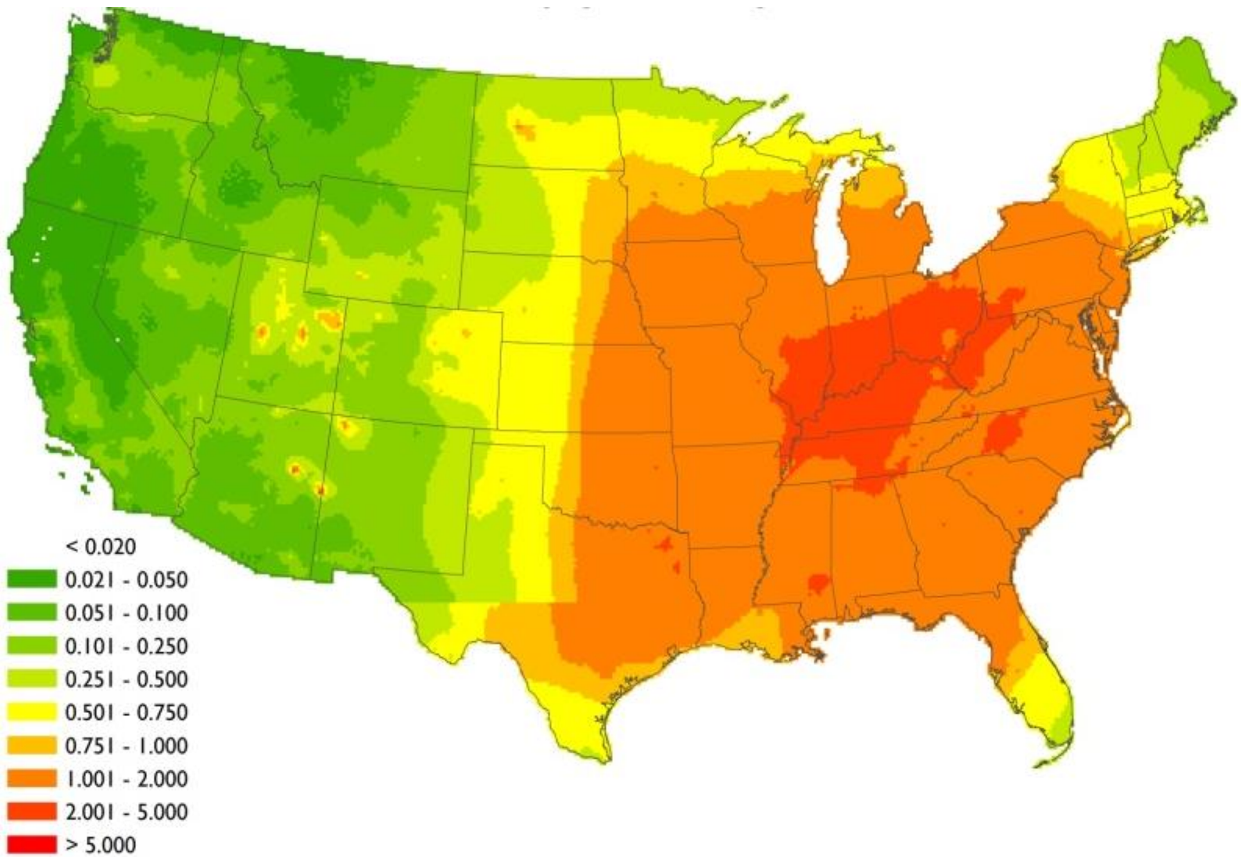

Figure 4A-2. Modeled $PM_{2.5}$ Concentrations Attributable to EGUs in 2016 (Annual Mean, in μg/m³) (Source: BPT TSD)

This method provides estimates of the regional average benefit-per-ton for each ambient $PM_{2.5}$ precursor emitted from EGU sources. For some precursor emissions, such as NOx, there is generally a non-linear relationship between emissions and formation of $PM_{2.5}$. This means that each ton of NOx reduced would have a different impact on ambient $PM_{2.5}$ depending on the initial level of emissions and potentially on the levels of emissions of other pollutants. In contrast, SO_2 is generally linear in forming $PM_{2.5}$. For non-linear pollutants like NOx, a marginal

[114] Currently, BenMAP does not have an inflation adjustment to 2011$. We ran BenMAP for a currency year of 2010$ and calculated the benefit-per-ton estimates in 2010$. We then adjusted the resulting benefit-per-ton estimates to 2011$ using the Consumer Price Index.

benefit-per-ton approach would better approximate the specific benefits associated with an emissions reduction scenario for a given set of base case emissions, but we do not have sufficient air quality modeling data to calculate a marginal benefit-per-ton estimates for the EGU sector. Therefore, using an average benefit-per-ton estimate for NOx adds uncertainty to the co-benefits estimated in this RIA. Because most of the estimated co-benefits for the proposed guidelines are attributable to reductions in SO_2 emissions, the added uncertainty is likely to be small.

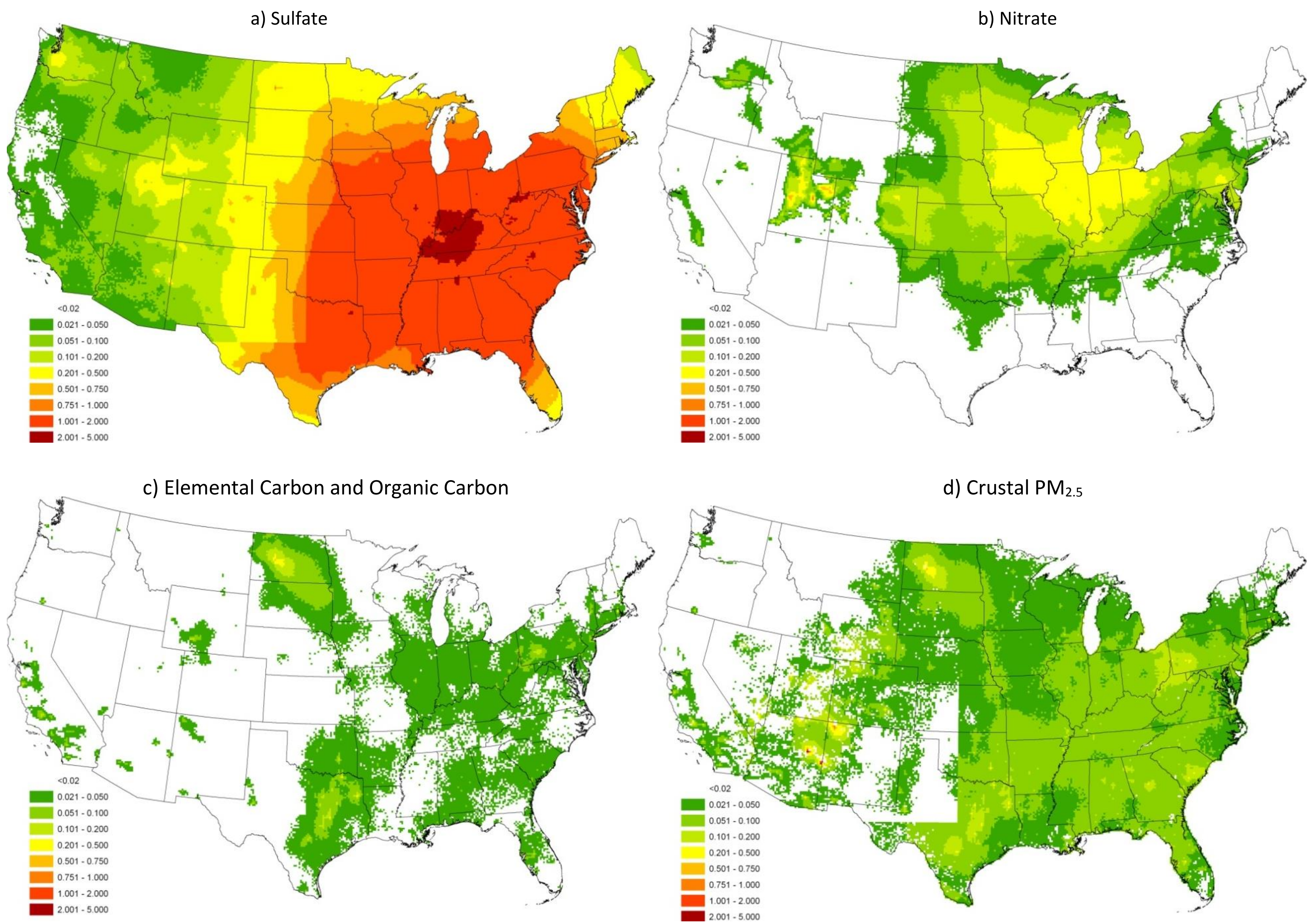

Figure 4A-3. Modeled $PM_{2.5}$ Concentrations Attributable to EGUs by Precursor in 2016 (Annual Mean, in µg/m^3)

Figure 4A-4. Regional Breakdown

Table 4A-1. Summary of National and Regional Emissions in Sector Modeling for EGUs in 2016 (in short tons)

Pollutant	National EGU emissions	Regional EGU Emissions		
		East	West	California
SO_2	3,793,362	3,520,296	273,070	4,886
Directly emitted $PM_{2.5}$ (EC+OC)	30,078	26,172	3,892	1,523
Directly emitted $PM_{2.5}$ (crustal)	243,497	214,219	28,438	840
NOx (all year)	1,826,582	1,425,148	401,584	13,485
NOx (ozone season)	931,189	728,402	195,748	7,039

In this RIA, we estimate emission reductions from EGUs using IPM.[115] IPM outputs provide endogenously projected unit level emissions of SO_2, NOx, CO_2, Hg, HCl from EGUs, but CO, VOC, NH_3 and total directly emitted $PM_{2.5}$ and PM_{10} emissions are post-calculated.[116] In

[115] See Chapter 3 of this RIA for additional information regarding IPM.

[116] Detailed documentation of this post-processing is available at http://www.epa.gov/powersectormodeling/docs/v513/FlatFile_Methodology.pdf

addition, directly emitted particle emissions calculated from IPM outputs do not include speciation, i.e. they are only the total emissions. In order to estimate the benefits associated with reduced emissions of directly emitted particles, we must determine the fraction of total $PM_{2.5}$ emissions comprised of elemental carbon and organic carbon (EC+OC) and crustal emissions.[117] Figure 4A-5 illustrates the relative breakdown of directly emitted $PM_{2.5}$ components from EGUs in the modeling by Fann, Baker, and Fulcher (2012). In this modeling, the national average EC+OC fraction of emitted $PM_{2.5}$ is 10% with a range of 5% to 63% in different states due to the different proportion of fuels. The national average is similar to the averages for the east and west regions at 10% and 7%, respectively. Only five states had EC+OC fractions greater than 30%. For crustal emissions, the national average fraction of emitted $PM_{2.5}$ from EGUs is 78% with a range of 26% to 83%. The national average is similar to the averages for the east and west regions at 78% and 81%, respectively. Only four states had crustal fractions less than 50%.

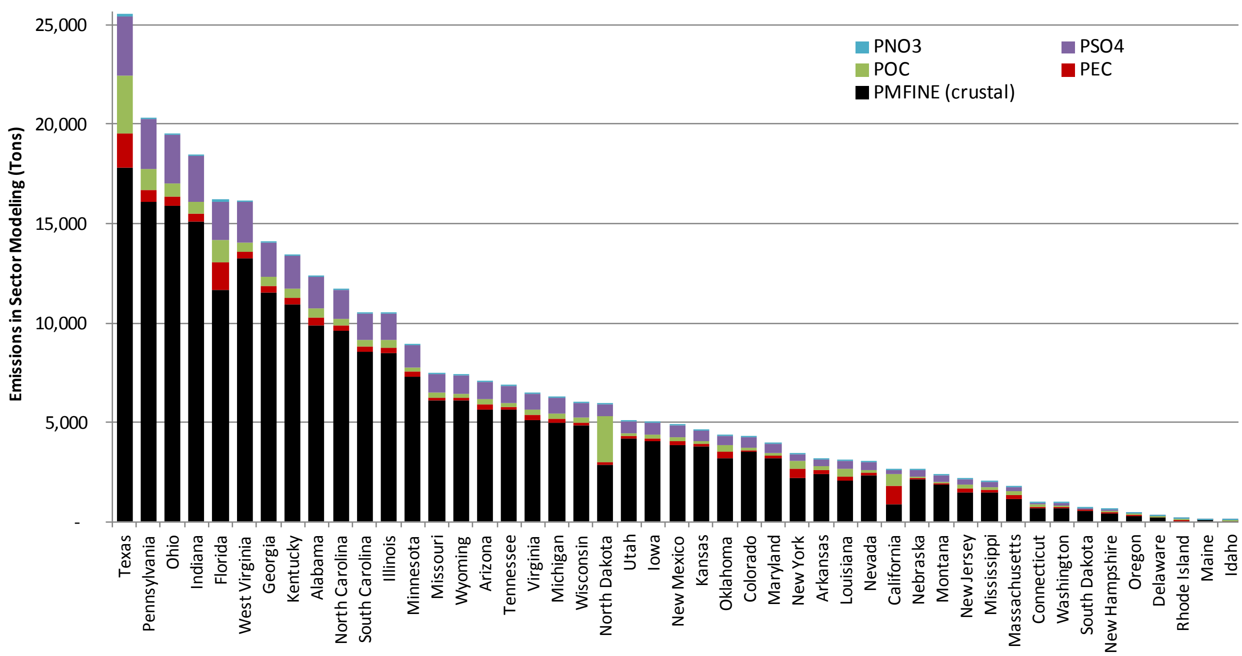

Figure 4A-5. Breakdown of Directly Emitted $PM_{2.5}$ Emissions from EGU in Sector Modeling

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[117] Crustal emissions are composed of compounds associated with minerals and metals from the earth's surface, including carbonates, silicates, iron, phosphates, copper, and zinc. Often, crustal material represents particles not classified as one of the other species (e.g., organic carbon, elemental carbon, nitrate, sulfate, chloride, etc.).

There are several uncertainties associated with estimating the benefits associated with reducing emissions of EC+OC and crustal $PM_{2.5}$ from EGUs. As previously mentioned, IPM does not estimate $PM_{2.5}$ emissions by component, and total $PM_{2.5}$ is estimated as an IPM post-processing step using emission factors. In order to conduct air quality modeling, $PM_{2.5}$ from EGUs is speciated into components during the emissions modeling process based on emission profiles for EGUs by source classification code. Even though these speciation profiles are not unit-specific, an emission profile based on the source classification code is highly sophisticated and reflects the fuel and the unit configuration. In addition, the air quality model output has been adjusted to match an interpolated surface of speciated $PM_{2.5}$ measurements, using the Model Attainment Test Software (Abt Associates, Inc, 2010). Uncertainties in some emissions sectors can sometimes be large enough that air quality estimates from well-characterized sectors such as EGUs may be changed to match observed monitor data. While these changes are usually minimal, in this instance, uncertainties in crustal emissions from other sectors impact the relationship between EGU crustal emissions and resulting air quality impacts. Because the co-benefits associated with directly emitted particles for the proposed guidelines are small relative to the co-benefits of reducing SO_2 emissions, these uncertainties would not substantially affect the estimate of total monetized health co-benefits.[118] In calculating the $PM_{2.5}$ co-benefits in this RIA, we estimate the emission reductions of EC+OC and crustal emissions by applying the national average fractions (i.e., 78% crustal and 10% EC+OC) to the emission reductions of all directly emitted particles from EGUs. Because the benefit-per-ton estimates for reducing emissions of EC+OC are larger than the benefit-per-ton estimate for crustal emissions, this assumption underestimates the monetized $PM_{2.5}$ co-benefits in certain states with higher EC+OC fractions, such as California and North Dakota. We further underestimate the co-benefits by not quantifying or monetizing the co-benefits associated with reducing directly emitted particulate nitrate and sulfate.

Although it is possible to calculate 95th percentile confidence intervals using the approach described in this appendix (e.g., U.S. EPA, 2011b), we generally do not calculate confidence intervals for benefit-per-ton estimates. Instead, we refer the reader to Chapter 5 of PM NAAQS

[118] See Figure 5-2 of this RIA for the relative proportion of health co-benefits from directly emitted particles relative to co-benefits from SO_2 emissions.

RIA (U.S. EPA, 2012a) for an indication of the combined random sampling error in the health impact and economic valuation functions using Monte Carlo methods. In general, the 95th percentile confidence interval for the total monetized $PM_{2.5}$ benefits ranges from approximately-90% to +180% of the central estimates based on concentration-response functions from Krewski et al. (2009) and Lepeule et al. (2012). The 95th percentile confidence interval for the health impact function alone ranges from approximately ±30% for mortality incidence based on Krewski et al. (2009) and ±46% based on Lepeule et al. (2012). These confidence intervals do not reflect other sources of uncertainty inherent within the estimates, such as baseline incidence rates, populations exposed, and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the benefits estimates.

Tables 4A-2 through 4A-4 provide the national and regional benefit-per-ton estimates for the EGU sector at discount rates of 3% and 7% in 2020, 2025, and 2030 respectively. Tables 4A-5 through 4A-7 provide the incidence per ton estimates for the EGU sector in 2020, 2025, and 2030 respectively.

Table 4A-2. Summary of National and Regional $PM_{2.5}$ Benefit-per-Ton Estimates for EGUs in 2020 (2011$)*

Pollutant	Discount Rate	National	Region: East	Region: West	Region: California
SO_2	3%	$38,000 to $86,000	$40,000 to $90,000	$7,800 to $18,000	$160,000 to $360,000
	7%	$34,000 to $77,000	$36,000 to $82,000	$7,100 to $16,000	$140,000 to $320,000
Directly emitted $PM_{2.5}$ (EC+OC)	3%	$140,000 to $320,000	$140,000 to $320,000	$56,000 to $130,000	$280,000 to $640,000
	7%	$130,000 to $290,000	$130,000 to $280,000	$50,000 to $110,000	$250,000 to $570,000
Directly emitted $PM_{2.5}$ (Crustal)	3%	$18,000 to $40,000	$18,000 to $41,000	$11,000 to $25,000	$110,000 to $240,000
	7%	$16,000 to $36,000	$16,000 to $37,000	$10,000 to $23,000	$95,000 to $220,000
NOx (as $PM_{2.5}$)	3%	$5,600 to $13,000	$6,700 to $15,000	$1,200 to $2,600	$17,000 to $38,000
	7%	$5,000 to $11,000	$6,000 to $14,000	$1,000 to $2,400	$15,000 to $34,000

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for $PM_{2.5}$. All estimates are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles. The estimates do not include reduced health effects from direct exposure to ozone, NO_2, SO_2, ecosystem effects, or visibility impairment.

Table 4A-3. Summary of National and Regional $PM_{2.5}$ Benefit-per-Ton Estimates for EGUs in 2025 (2011$)*

Pollutant	Discount Rate	National	Region: East	Region: West	Region: California
SO_2	3%	$41,000 to $93,000	$44,000 to $98,000	$8,800 to $20,000	$180,000 to $410,000
	7%	$37,000 to $84,000	$39,000 to $89,000	$8,000 to $18,000	$160,000 to $370,000
Directly emitted $PM_{2.5}$ (EC+OC)	3%	$150,000 to $350,000	$150,000 to $340,000	$64,000 to $140,000	$320,000 to $720,000
	7%	$140,000 to $310,000	$140,000 to $310,000	$58,000 to $130,000	$290,000 to $650,000
Directly emitted $PM_{2.5}$ (Crustal)	3%	$17,000 to $39,000	$18,000 to $40,000	$12,000 to $27,000	$43,000 to $96,000
	7%	$15,000 to $35,000	$16,000 to $36,000	$11,000 to $24,000	$38,000 to $87,000
NOx (as $PM_{2.5}$)	3%	$6,000 to $14,000	$7,200 to $16,000	$1,300 to $2,900	$19,000 to $42,000
	7%	$5,400 to $12,000	$6,500 to $15,000	$1,200 to $2,600	$17,000 to $38,000

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for $PM_{2.5}$. All estimates are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles. The estimates do not include reduced health effects from direct exposure to ozone, NO_2, SO_2, ecosystem effects, or visibility impairment.

Table 4A-4. Summary of National and Regional $PM_{2.5}$ Benefit-per-Ton Estimates for EGUs in 2030 (2011$)*

Pollutant	Discount Rate	National	Region		
			East	West	California
SO_2	3%	$44,000 to $100,000	$47,000 to $110,000	$9,800 to $22,000	$200,000 to $450,000
	7%	$40,000 to $90,000	$42,000 to $95,000	$8,800 to $20,000	$180,000 to $410,000
Directly emitted $PM_{2.5}$ (EC+OC)	3%	$170,000 to $370,000	$160,000 to $370,000	$71,000 to $160,000	$360,000 to $800,000
	7%	$150,000 to $340,000	$150,000 to $330,000	$64,000 to $150,000	$320,000 to $730,000
Directly emitted $PM_{2.5}$ (Crustal)	3%	$18,000 to $42,000	$19,000 to $43,000	$13,000 to $30,000	$47,000 to $110,000
	7%	$17,000 to $38,000	$17,000 to $38,000	$12,000 to $27,000	$43,000 to $96,000
NOx (as $PM_{2.5}$)	3%	$6,400 to $14,000	$7,600 to $17,000	$1,400 to $3,200	$21,000 to $42,000
	7%	$5,800 to $13,000	$6,900 to $16,000	$1,300 to $2,900	$19,000 to $47,000

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for $PM_{2.5}$. All estimates are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles. The estimates do not include reduced health effects from direct exposure to ozone, NO_2, SO_2, ecosystem effects, or visibility impairment.

Table 4A-5. Summary of Regional $PM_{2.5}$ Incidence-per-Ton Estimates for EGUs in 2020*

Health Endpoint	East				West				California			
	SO_2	NOx	EC+OC	Crustal	SO_2	NOx	EC+OC	Crustal	SO_2	NOx	EC+OC	Crustal
Premature Mortality												
Krewski et al. (2009) – adult	0.004400	0.000730	0.015000	0.002000	0.000860	0.000130	0.006100	0.001200	0.017000	0.001800	0.031000	0.012000
Lepeule et al. (2012) – adult	0.009900	0.001700	0.035000	0.004500	0.001900	0.000290	0.014000	0.002800	0.039000	0.004100	0.070000	0.026000
Woodruff et al. (1997) – infants	0.000010	0.000002	0.000033	0.000004	0.000002	0.000000	0.000016	0.000003	0.000036	0.000004	0.000067	0.000025
Morbidity												
Emergency department visits for asthma	0.002300	0.000410	0.008700	0.001000	0.000380	0.000055	0.002800	0.000520	0.008600	0.001000	0.016000	0.005900
Acute bronchitis	0.006300	0.001100	0.022000	0.002800	0.001600	0.000330	0.011000	0.002300	0.031000	0.003400	0.057000	0.021000
Lower respiratory symptoms	0.081000	0.014000	0.290000	0.036000	0.021000	0.004200	0.150000	0.029000	0.390000	0.044000	0.720000	0.270000
Upper respiratory symptoms	0.120000	0.020000	0.410000	0.051000	0.030000	0.006000	0.210000	0.042000	0.560000	0.062000	1.000000	0.390000
Minor restricted-activity days	3.200000	0.540000	11.000000	1.400000	0.780000	0.130000	5.400000	1.000000	16.00000	1.700000	29.00000	11.00000
Lost work days	0.540000	0.090000	1.900000	0.240000	0.130000	0.023000	0.910000	0.180000	2.700000	0.290000	4.900000	1.800000
Asthma exacerbation	0.290000	0.020000	0.420000	0.053000	0.074000	0.006200	0.220000	0.043000	1.400000	0.064000	1.100000	0.400000
Hospital Admissions, Respiratory	0.001300	0.000220	0.004500	0.000580	0.000190	0.000026	0.001400	0.000270	0.004100	0.000440	0.007400	0.002800
Hospital Admissions, Cardiovascular	0.001600	0.000270	0.005600	0.000720	0.000220	0.000032	0.001800	0.000340	0.005000	0.000520	0.009000	0.003400
Non-fatal Heart Attacks (Peters)	0.005000	0.000860	0.018000	0.002300	0.000810	0.000110	0.006000	0.001200	0.018000	0.001900	0.032000	0.012000
Non-fatal Heart Attacks (All others)	0.000550	0.000093	0.001900	0.000250	0.000087	0.000012	0.000640	0.000130	0.001900	0.000210	0.003400	0.001300

* All estimates are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but the incidence-per-ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The incidence benefit-per-ton estimates incorporate the conversion from precursor emissions to ambient fine particles.

Table 4A-6. Summary of Regional $PM_{2.5}$ Incidence-per-Ton Estimates for EGUs in 2025*

Health Endpoint	East				West				California			
	SO_2	NOx	EC+OC	Crustal	SO_2	NOx	EC+OC	Crustal	SO_2	NOx	EC+OC	Crustal
Premature Mortality												
Krewski et al. (2009) – adult	0.004700	0.000770	0.016000	0.002100	0.000940	0.000140	0.006800	0.001400	0.019000	0.002000	0.034000	0.013000
Lepeule et al. (2012) – adult	0.011000	0.001700	0.037000	0.004800	0.002100	0.000310	0.015000	0.003100	0.043000	0.004500	0.077000	0.029000
Woodruff et al. (1997) – infants	0.000009	0.000001	0.000031	0.000004	0.000002	0.000000	0.000016	0.000003	0.000034	0.000004	0.000063	0.000024
Morbidity												
Emergency department visits for asthma	0.002400	0.000420	0.009000	0.001100	0.000410	0.000059	0.003000	0.000560	0.009000	0.001000	0.016000	0.006100
Acute bronchitis	0.006600	0.001100	0.023000	0.002900	0.001700	0.000350	0.012000	0.002400	0.032000	0.003600	0.059000	0.022000
Lower respiratory symptoms	0.084000	0.014000	0.300000	0.037000	0.022000	0.004400	0.150000	0.031000	0.410000	0.046000	0.760000	0.290000
Upper respiratory symptoms	0.120000	0.020000	0.430000	0.053000	0.032000	0.006300	0.220000	0.044000	0.590000	0.065000	1.100000	0.410000
Minor restricted-activity days	3.200000	0.540000	12.000000	1.400000	0.820000	0.140000	5.700000	1.100000	16.00000	1.70000	30.00000	11.00000
Lost work days	0.550000	0.091000	2.000000	0.240000	0.140000	0.024000	0.970000	0.190000	2.700000	0.300000	5.000000	1.800000
Asthma exacerbation	0.300000	0.021000	0.440000	0.055000	0.078000	0.006500	0.230000	0.046000	1.400000	0.067000	1.100000	0.420000
Hospital Admissions, Respiratory	0.001400	0.000240	0.005000	0.000640	0.000220	0.000030	0.001600	0.000320	0.004800	0.000500	0.008500	0.003200
Hospital Admissions, Cardiovascular	0.001800	0.000290	0.006100	0.000780	0.000250	0.000036	0.002000	0.000390	0.005600	0.000580	0.010000	0.003800
Non-fatal Heart Attacks (Peters)	0.005500	0.000930	0.019000	0.002500	0.000910	0.000120	0.006800	0.001300	0.020000	0.002100	0.036000	0.013000
Non-fatal Heart Attacks (All others)	0.000600	0.000100	0.002100	0.000270	0.000098	0.000013	0.000730	0.000140	0.002200	0.000230	0.003900	0.001500

* All estimates are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but the incidence-per-ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The incidence benefit-per-ton estimates incorporate the conversion from precursor emissions to ambient fine particles.

Table 4A-7. Summary of Regional $PM_{2.5}$ Incidence-per-Ton Estimates for EGUs in 2030*

Health Endpoint	East				West				California			
	SO_2	NOx	EC+OC	Crustal	SO_2	NOx	EC+OC	Crustal	SO_2	NOx	EC+OC	Crustal
Premature Mortality	0.005000	0.000810	0.017000	0.002300	0.001000	0.000150	0.007600	0.001500	0.021000	0.002200	0.038000	0.014000
Krewski et al. (2009) – adult	0.011000	0.001800	0.040000	0.005100	0.002400	0.000340	0.017000	0.003400	0.048000	0.005000	0.086000	0.032000
Lepeule et al. (2012) – adult	0.000009	0.000001	0.000030	0.000004	0.000002	0.000000	0.000015	0.000003	0.000032	0.000004	0.000060	0.000023
Woodruff et al. (1997) – infants												
Morbidity	0.002500	0.000430	0.009300	0.001100	0.000430	0.000062	0.003200	0.000600	0.009400	0.001100	0.017000	0.006400
Emergency department visits for asthma	0.006800	0.001100	0.024000	0.003000	0.001800	0.000370	0.013000	0.002600	0.033000	0.003700	0.061000	0.023000
Acute bronchitis	0.087000	0.014000	0.310000	0.038000	0.023000	0.004700	0.170000	0.033000	0.420000	0.047000	0.780000	0.300000
Lower respiratory symptoms	0.130000	0.021000	0.440000	0.055000	0.034000	0.006700	0.240000	0.047000	0.610000	0.067000	1.100000	0.420000
Upper respiratory symptoms	3.300000	0.540000	12.000000	1.500000	0.860000	0.150000	6.000000	1.200000	17.00000	1.800000	30.00000	11.00000
Minor restricted-activity days	0.560000	0.092000	2.000000	0.250000	0.150000	0.025000	1.000000	0.200000	2.800000	0.300000	5.100000	1.900000
Lost work days	0.310000	0.021000	0.460000	0.057000	0.082000	0.006900	0.240000	0.048000	1.500000	0.069000	1.200000	0.430000
Asthma exacerbation	0.001600	0.000260	0.005500	0.000710	0.000250	0.000034	0.001800	0.000360	0.005500	0.000580	0.009900	0.003700
Hospital Admissions, Respiratory	0.001900	0.000320	0.006700	0.000850	0.000280	0.000041	0.002300	0.000440	0.006400	0.000660	0.012000	0.004300
Hospital Admissions, Cardiovascular	0.006000	0.001000	0.021000	0.002700	0.001000	0.000140	0.007700	0.001500	0.023000	0.002400	0.041000	0.015000
Non-fatal Heart Attacks (Peters)	0.000660	0.000110	0.002300	0.000290	0.000110	0.000015	0.000830	0.000160	0.002500	0.000260	0.004400	0.001700
Non-fatal Heart Attacks (All others)	0.005000	0.000810	0.017000	0.002300	0.001000	0.000150	0.007600	0.001500	0.021000	0.002200	0.038000	0.014000

* All estimates are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but the incidence-per-ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The incidence benefit-per-ton estimates incorporate the conversion from precursor emissions to ambient fine particles.

4A.4 Regional Ozone Benefit-per-Ton Estimates

The process for generating the regional ozone benefit-per-ton estimates is consistent with the process for $PM_{2.5}$. The key difference is substituting the ozone impacts from EGUs in the sector modeling for the $PM_{2.5}$ impacts. We have not historically generated ozone benefit-per-ton estimates due to the complex non-linearity in the atmospheric response to changes in ozone precursor pollutants from different sectors in different geographic areas. However, for EGUs, we have increased confidence in the magnitude and location of ozone-season NOx emissions and ambient ozone concentrations attributable to these emissions. In addition, the sector modeling provides information regarding the total EGU contribution to ozone formation, which provides greater transferability than an air quality modeling scenario for a regulation that might include both increases and decreases in emissions in different locations. Figure 4A-6 provides the average ambient ozone concentrations from the EGU sector in the sector modeling for 2016.[119]

[119] The 2016 air quality modeling simulations do not reflect emission reductions anticipated from the EGU sector as a result of the recently promulgated MATS rule, and so may overstate the total ozone contribution from this sector. (Fann, Fulcher, and Baker (2013). However, the EGU contribution on a per-ton basis would likely be similar. Because the emission reductions in this RIA are calculated from an IPM base case that includes MATS (see Chapter 3), there is no double-counting concern with the resulting co-benefits estimates.

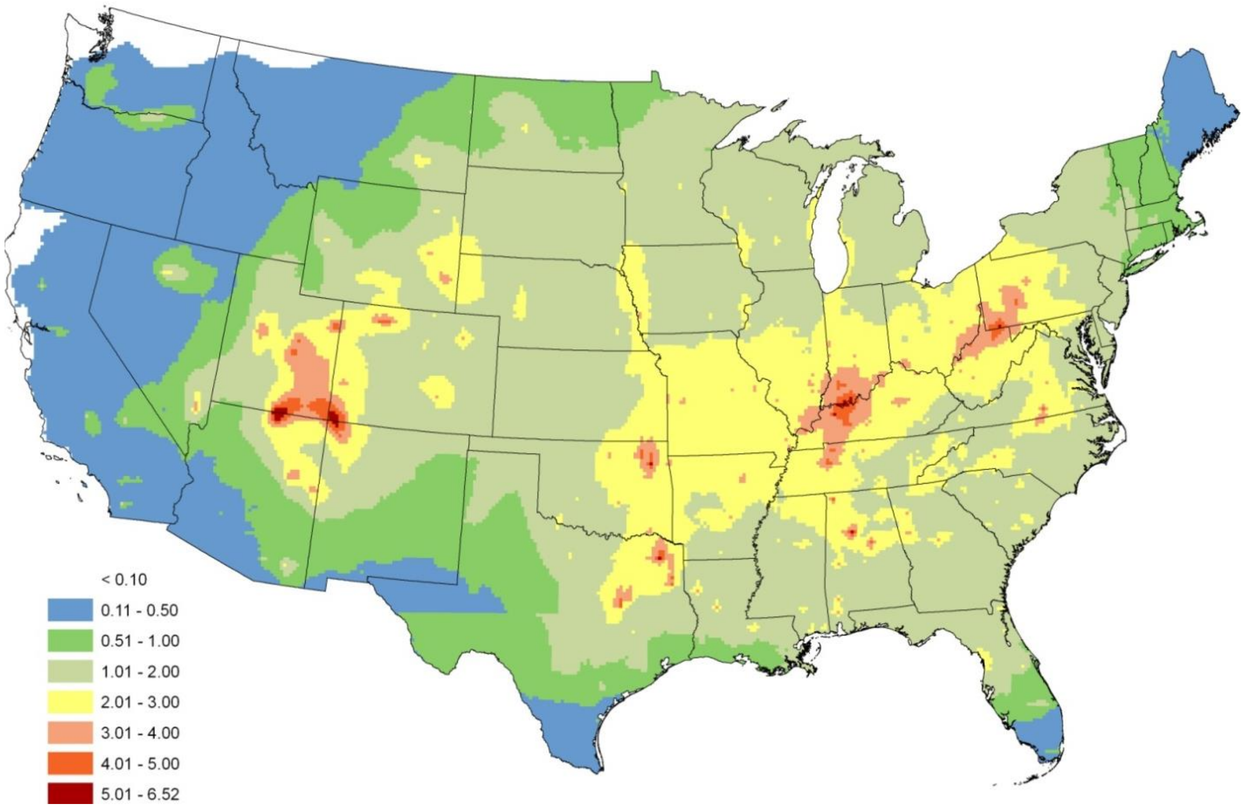

Figure 4A-6. Modeled Average Ozone Concentrations Attributable to EGUs in 2016 (Daily 8-hour maximum, May-September, in ppb)

We assume that all of the ozone impacts from EGUs are attributable to NOx emissions. VOC emissions, which are also a precursor to ambient ozone formation, are insignificant from the EGU sector relative to NOx emissions from EGUs and the total VOC emissions inventory. Therefore, we believe that our assumption that EGU-attributable ozone formation at the regional-level is due to NOx alone is reasonable.

Similar to $PM_{2.5}$, this method provides estimates of the regional average benefit-per-ton. Due to the non-linear chemistry between NOx emissions and ambient ozone, using an average benefit-per-ton estimate for NOx adds uncertainty to the ozone co-benefits estimated for the proposed guidelines. Because most of the estimated co-benefits for the proposed guidelines are attributable to changes in ambient $PM_{2.5}$, the added uncertainty is likely to be small.

In the ozone co-benefits estimated in this RIA, we apply the benefit-per-ton estimates calculated using NO_X emissions from U.S. EGUs during the ozone-season only (May to September). As shown in Table 4A-1, ozone-season NOx emissions from EGUs are approximately half of all-year NO_X emissions. Because we estimate ozone health impacts from May to September only, this approach underestimates ozone co-benefits in areas with a longer ozone seasons such as southern California and Texas. When the underestimated benefit-per-ton estimate is multiplied by ozone-season only NOx emission reductions, this results in an underestimate of the monetized ozone co-benefits. For illustrative purposes, Tables 4A-8 through 4A-10 provide the ozone benefit-per-ton estimates using both all-year NOx emissions and ozone-season only NOx for 2020, 2025, and 2030, respectively. Tables 4A-11 through 4A-13 provide the ozone season incidence-per-ton estimates for 2020, 2025, and 2030, respectively.

Table 4A-8. Summary of National and Regional Ozone Benefit-per-Ton Estimates for EGUs in 2020 (2011$)*

Ozone precursor Pollutant	National	Regional		
		East	West	California
Ozone season NOx	$3,800 to $16,000	$4,600 to $19,000	$930 to $4,000	$7,400 to $31,000
All-year NOx	$1,900 to $8,000	$2,300 to $9,600	$450 to $2,000	$3,800 to $16,000

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for ozone. All estimates are rounded to two significant figures. The monetized benefits incorporate the conversion from NOx precursor emissions to ambient ozone.

Table 4A-9. Summary of National and Regional Ozone Benefit-per-Ton Estimates for EGUs in 2025 (2011$)*

Ozone precursor Pollutant	National	Regional		
		East	West	California
Ozone season NOx	$4,900 to $21,000	$5,900 to $25,000	$1,200 to $5,400	$9,900 to $42,000
All-year NOx	$2,500 to $11,000	$3,000 to $13,000	$650 to $2,800	$5,200 to $22,000

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for ozone. All estimates are rounded to two significant figures. The monetized benefits incorporate the conversion from NOx precursor emissions to ambient ozone.

Table 4A-10. Summary of National and Regional Ozone Benefit-per-Ton Estimates for EGUs in 2030 (2011$)*

Ozone precursor Pollutant	National	Regional		
		East	West	California
Ozone season NOx	$5,300 to $23,000	$6,300 to $27,000	$1,400 to $6,000	$11,000 to $47,000
All-year NOx	$2,700 to $12,000	$3,200 to $14,000	$730 to $3,200	$5,700 to $25,000

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for ozone. All estimates are rounded to two significant figures. The monetized benefits incorporate the conversion from NOx precursor emissions to ambient ozone.

Table 4A-11. Summary of Regional Ozone Incidence-per-Ton Estimates for EGUs in 2020*

Health Endpoint	East	West	California
Premature Mortality – adult			
Bell et al. (2004)	0.000260	0.000053	0.000420
Levy et al. (2005)	0.001200	0.000250	0.001900
Morbidity			
Hospital Admissions, Respiratory (ages > 65)	0.001600	0.000250	0.002200
Hospital Admissions, Respiratory (ages < 2)	0.000710	0.000220	0.001200
Emergency Room Visits, Respiratory	0.000840	0.000150	0.001300
Acute Respiratory Symptoms	1.500000	0.380000	3.000000
School Loss Days	0.510000	0.140000	1.000000

* All estimates are rounded to two significant figures. The incidence benefit-per-ton estimates incorporate the conversion from NOx precursor emissions to ambient ozone. These estimates reflect ozone-season NOx emissions.

Table 4A-12. Summary of Regional Ozone Incidence-per-Ton Estimates for EGUs in 2025*

Health Endpoint	East	West	California
Premature Mortality – adult			
Bell et al. (2004)	0.000530	0.000110	0.000890
Levy et al. (2005)	0.002400	0.000520	0.004100
Morbidity			
Hospital Admissions, Respiratory (ages > 65)	0.003500	0.000590	0.004900
Hospital Admissions, Respiratory (ages < 2)	0.001400	0.000440	0.002300
Emergency Room Visits, Respiratory	0.001700	0.000300	0.002700
Acute Respiratory Symptoms	3.000000	0.770000	5.900000
School Loss Days	1.000000	0.290000	2.100000

* All estimates are rounded to two significant figures. The incidence benefit-per-ton estimates incorporate the conversion from NOx precursor emissions to ambient ozone. These estimates reflect ozone-season NOx emissions.

Table 4A-13. Summary of Regional Ozone Incidence-per-Ton Estimates for EGUs in 2030*

Health Endpoint	East	West	California
Premature Mortality – adult			
Bell et al. (2004)	0.000570	0.000130	0.001000
Levy et al. (2005)	0.002600	0.000580	0.004500
Morbidity			
Hospital Admissions, Respiratory (ages > 65)	0.004000	0.000690	0.005900
Hospital Admissions, Respiratory (ages < 2)	0.001400	0.000460	0.002400
Emergency Room Visits, Respiratory	0.001800	0.000320	0.002800
Acute Respiratory Symptoms	3.000000	0.810000	6.000000
School Loss Days	1.100000	0.310000	2.200000

* All estimates are rounded to two significant figures. The incidence benefit-per-ton estimates incorporate the conversion from NOx precursor emissions to ambient ozone. These estimates reflect ozone-season NOx emissions.

4A.5 Evaluating the Benefit-per-Ton Estimates

In this section, we provide information that can be used to evaluate the regional benefit-per-ton estimates and provide some characterization of the uncertainty inherent in these estimates relative to benefits estimated using scenario-specific air quality modeling. First, we evaluated how well the spatial distribution of emissions underlying the regional benefit-per-ton estimates match the spatial distribution of the emissions for the illustrative compliance scenarios for the proposed guidelines. Second, we evaluated how well the national and regional benefit-per-ton estimates predicted modeled benefits estimated for MATS (U.S. EPA, 2011b) and CSAPR (U.S. EPA, 2011c).

For the first evaluation, we provide graphs of the EGU emissions in each state in the sector modeling base case used to generate the regional benefit-per-ton estimates and the emissions in the IPM base case for this RIA, as shown in Figures 4A-7 through 4A-9. It is important to note that these graphs do not show the emission reductions anticipated from implementation of the proposed guidelines. Rather, these graphs illustrate the similarities and differences in the spatial distribution of the emissions from the EGU sector from the different base cases in order to evaluate the potential uncertainty associated with using the benefit-per-ton estimates to estimate the health co-benefits of the proposed guidelines. As noted in section 4A-2 above, the sector modeling base case does not reflect emission reductions anticipated from the EGU sector as a result of the recently promulgated MATS rule,[120] but the IPM base case does reflect those emission reductions. Even though the sector modeling has substantially more SO_2 emissions from EGUs (3.8 million tons in 2016 vs. 1.5 million tons in 2020), the spatial distribution is relatively similar across states and thus the resulting benefit-per-ton would likely be similar. Therefore, we would not expect this difference to have a substantial effect on the resulting co-benefits estimated for the proposed guidelines. Base case emissions for annual NOx and ozone-season NOx are also reasonably similar.

[120] See Figure 5C-1 from the MATS RIA (U.S. EPA, 2011b) for more information regarding the state-level SO_2 emission reductions anticipated from MATS.

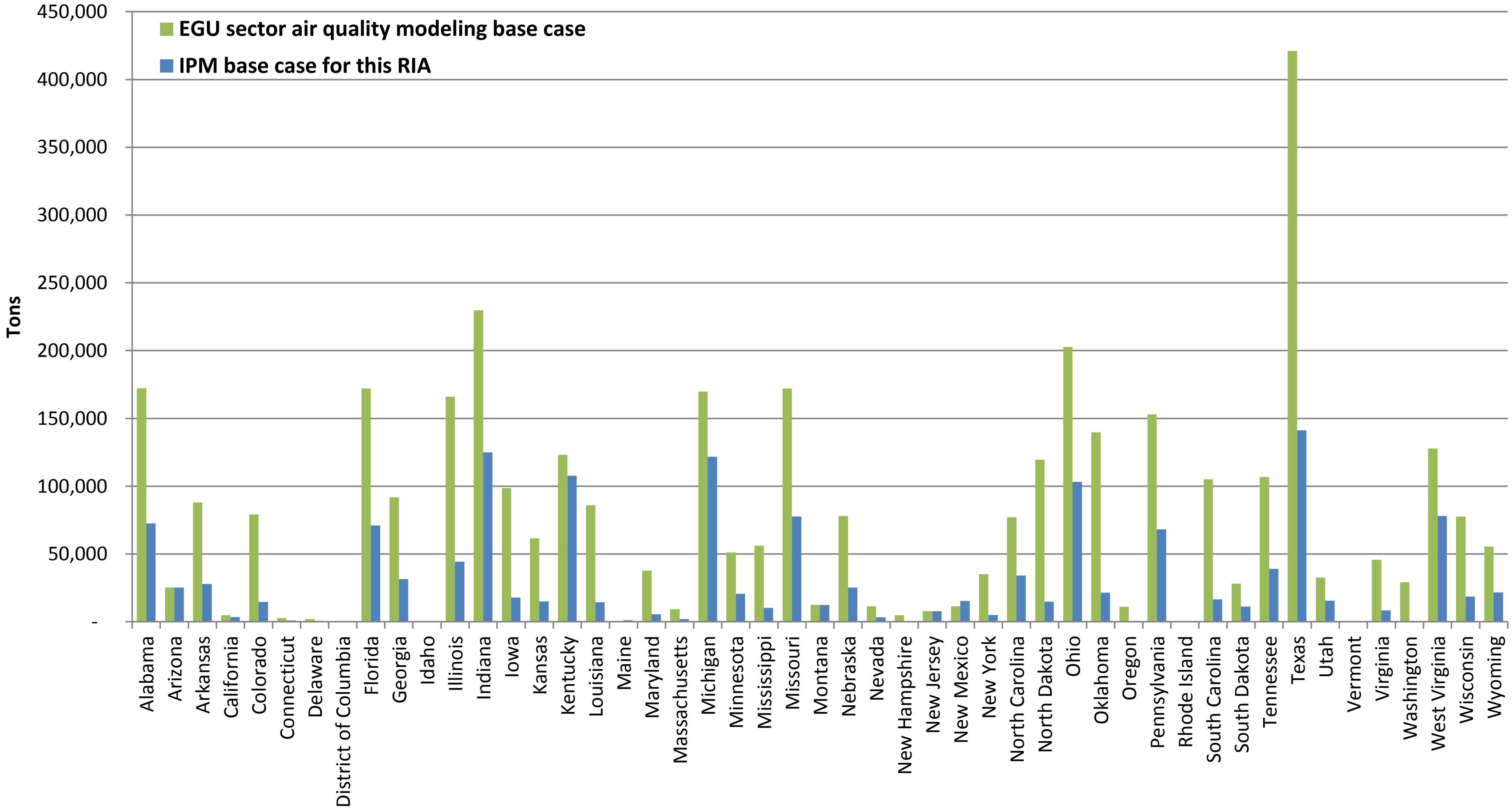

Figure 4A-7. Comparison of Base Case SO_2 Emissions in 2020

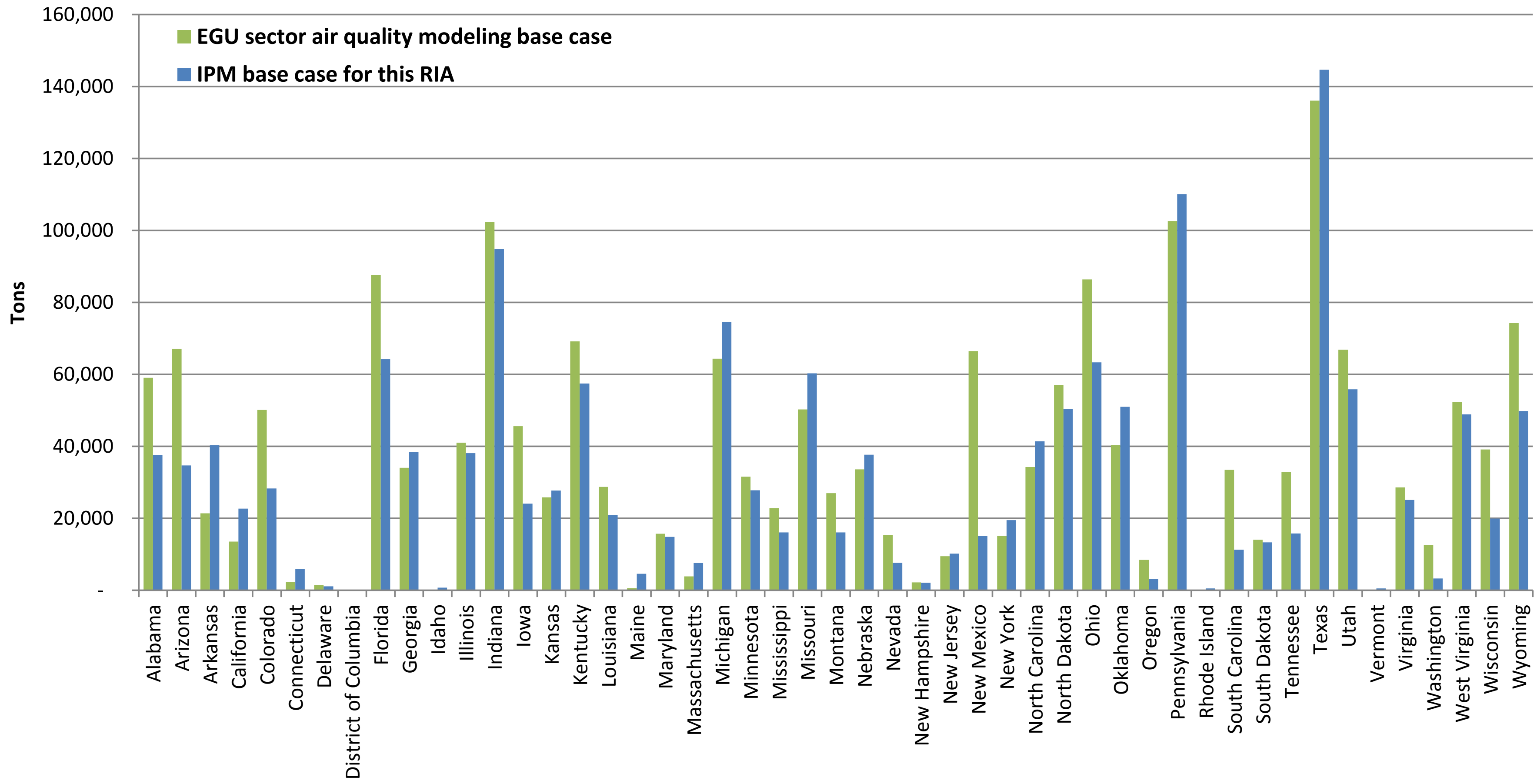

Figure 4A-8. Comparison of Base Case Annual NOx Emissions in 2020

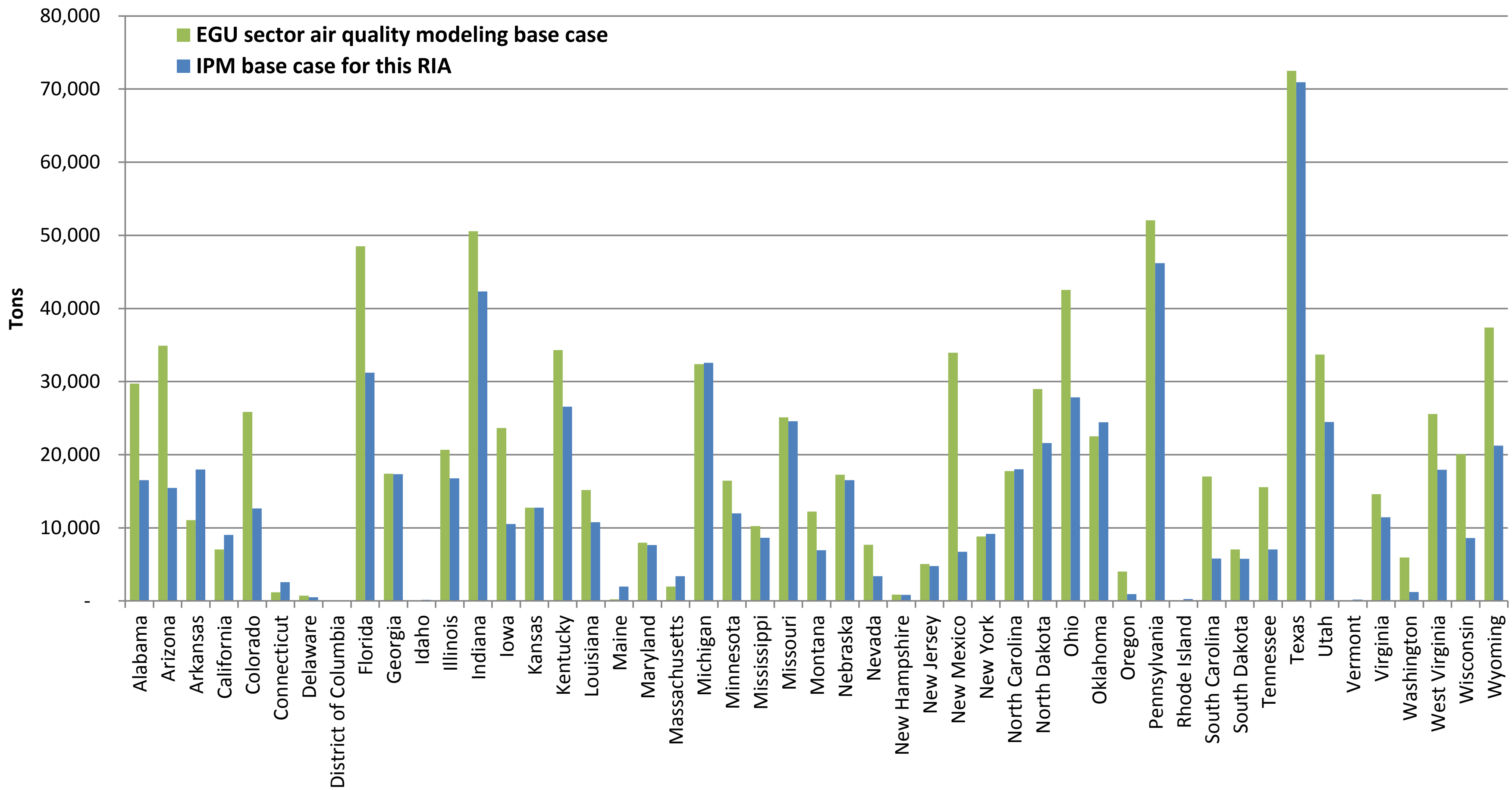

Figure 4A-9. Comparison of Base Case Ozone-season NOx Emissions in 2020

For the second evaluation, we used the national and regional benefit-per-ton estimates to estimate the modeled sulfate benefits estimated for MATS and CSAPR.[121] We focused on sulfate because the vast majority of $PM_{2.5}$ benefits for both rules were from reductions in ambient sulfate. We found that the national benefit-per-ton estimates overestimated the modeled CSAPR benefits by 7 percent and the MATS benefits by 33 percent. The regional benefit-per-ton estimates overestimated the CSAPR benefits by 14 percent and MATS benefits by 29 percent. This evaluation shows that the national and regional benefit-per-ton estimates perform reasonably well, with a slight overestimate, but this does not mean that the co-benefits estimated for the proposed guidelines would necessarily be within a similar range.

We also evaluated whether available modeling information could be used to generate reliable state-level benefit-per-ton estimates for $PM_{2.5}$.[122] In general, we would expect state-level estimates to better reflect the spatial differences in emission reductions and associated health impacts across scenarios than regional estimates, which implicitly assume a constant percentage of emission reductions across the region. Varying percentage reductions across states are further magnified by spatial differences in population density, base case health incidence rates, air quality response, and interstate pollution transport.

We tested several methods for generating state-level benefit-per-ton estimates. The method that performed best used state-by-state contribution modeling in the Eastern U.S. conducted for CSAPR (U.S. EPA, 2011a) to adjust the regional benefit-per-ton estimates for the EGU sector. Although the CSAPR modeling is the best available for estimating state-level benefit-per-ton estimates, it zeroed-out all anthropogenic emission sources within a state rather than just zeroing-out the emissions from the EGU sector alone. Currently, we do not have air quality modeling that provides information regarding the $PM_{2.5}$ response to EGU only emissions for each state separately. We evaluated the performance of the state-level estimates by comparing the modeled benefits for two previous rulemakings (i.e., CSAPR and MATS) to the

[121] The benefits analyses for both the MATS and CSAPR RIAs relied on benefit-per-ton estimates generated from similar policy-specific air quality modeling conducted specifically for those rulemakings. For this evaluation, we compared the benefits estimated from the air quality modeling, not the benefits estimated for the final rules in the RIA generated using the benefit-per-ton estimates for those rulemakings.

[122] We did not attempt to generate state-level ozone benefit-per-ton estimates due to inter-state transport, complex atmospheric chemistry, and localized impacts from VOC emissions.

benefits estimated using state-level benefit-per-ton. When we evaluated the state-level estimates in the same manner as the national and regional estimates, we found that the state-level estimates performed similarly, in general, to the regional estimates for estimating total national benefits but were unreliable in estimating the benefits that would accrue to each state. In addition, because the spatial differences in emission reductions between the options evaluated in this RIA are small, using the state-level estimates did not make a difference in the relative co-benefits across options.

4A.6 References

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CHAPTER 5: ECONOMIC IMPACTS – MARKETS OUTSIDE THE ELECTRICITY SECTOR

5.1 Introduction

The energy sector impacts presented in Chapter 3 of this regulatory impact analysis (RIA) include projected changes in the prices for electricity, natural gas, and coal resulting from the proposed Electric Utility Generating Unit (EGU) Existing Source Greenhouse Gas (GHG) Guidelines. This chapter addresses the impact of these changes on other markets and discusses some of the determinants of the magnitude of these impacts.

Under the proposed EGU Existing Source GHG Guidelines states are not required to use any of the measures that the EPA determines constitute BSER, or use those measures to the same degree of stringency that the EPA determines is achievable at reasonable cost; rather, CAA section 111(d) allows each state to determine the appropriate combination of, and the extent of its reliance on, measures for its state plan, by way of meeting its state-specific goal. Given the flexibilities afforded states in complying with the emission guidelines, the benefits, cost and economic impacts reported in this RIA are illustrative of compliance actions states may take. The compliance approaches adopted by the states will ultimately drive the magnitude and timing of impacts on the prices of electricity, natural gas, and coal and in turn other markets that use these commodities in the production process. The flexibility afforded to states by the Clean Air Act also allows them to adopt programs which include design elements that may mitigate or promote particular impacts based on their priorities. For example, states in the Regional Greenhouse Gas Initiative use the revenues from allowance auctions to support direct bill assistance for retail consumers, fund investments in clean energy and electricity demand reduction for business consumers, and support employment in the development of clean and renewable energy technologies. In its recent regulations to limit GHG emissions, California's Air Resources Board designated a portion of allowances to be allocated to electric distribution companies for the purpose of mitigating electricity rate increases and their associated impacts. Other states may choose to comply with particularly robust deployment of renewables, energy efficiency, or natural gas in order to promote manufacturing demand or employment in those sectors. For example, energy efficiency investments may be targeted towards reducing both electricity consumption and natural gas or heating oil consumption, such as weatherization projects. The composition of these programs will influence the effects of the state's compliance with the proposed rulemaking.

To support the Transport Rule proposed in the summer of 2010, among other rulemakings, the EPA used the Economic Model for Policy Analysis (EMPAX) to estimate the effect of impacts projected by the Integrated Planning Model (IPM) on markets outside the electricity sector. EMPAX is a dynamic computable general equilibrium (CGE) model that forecasts a new equilibrium for the entire economy after a policy intervention. While the external Council on Clean Air Compliance Analysis (Council) peer review of this study stated that inclusion of benefits in an economy-wide model, specifically adapted for use in that study, "represent[ed] a significant step forward in benefit-cost analysis," EPA recognizes that serious technical challenges remain when attempting to evaluate the benefits and costs of potential regulatory actions using economy-wide models. Consistent with the Council's advice regarding the importance of including benefit-side effects demonstrated by the 1990 to 2020 Clean Air Act study, and the lack of available multi-year air quality projections needed to include these benefit-side effects, EPA has not conducted CGE modeling for this proposal.

However, the EPA recognizes that serious technical challenges remain when attempting to evaluate the impacts of potential regulatory actions using economy-wide models. The EPA is therefore establishing a new Science Advisory Board (SAB) panel on economy-wide modeling to consider the technical merits and challenges of using this analytical tool to evaluate costs, benefits, and economic impacts in regulatory development. The EPA will use the recommendations and advice of this panel as an input into its process for improving benefit-cost and economic impact analyses that are used to inform decision-making at the agency. The panel will also be asked to identify potential paths forward for improvements that could address the challenges posed when economy-wide models are used to evaluate the effects of regulations.

The advice from the Science Advisory Board (SAB) panel formed specifically to address the subject of economy-wide modeling will not be available in time for this proposal. Given the ongoing SAB panel on economy-wide modeling, the uncertain nature of the ultimate energy price impacts due to the compliance flexibility for states, and the ongoing challenges of accurately representing costs, energy efficiency savings and economic benefits in economy-wide modeling, this chapter proceeds by presenting the energy impacts associated with the illustrative scenarios analyzed in Chapter 3. This chapter then presents a qualitative discussion of the factors that will, in part, determine the timing and magnitude of effects in other markets.

5.2 Summary of Secondary Market Impacts of Energy Price Changes

Electricity, natural gas, and coal are important inputs to the production of other goods and services. Therefore, changes in the price of these commodities will shift the production costs for sectors that use electricity, natural gas, and coal in the production of other goods and services. Such changes in production costs may lead to changes in the quantities and/or prices of the goods or services produced and changes in imports and exports. We refer to these changes as secondary market impacts.

The EPA used IPM to estimate electricity, natural gas, and coal price changes based on the illustrative compliance approaches modeled for this proposal. IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector that is described in more detail in Chapter 3. The prices are average prices weighted by the amount used. Table 5-1 shows these estimated price changes. For other results generated by IPM, please refer to Chapter 3.

There are many factors influencing the projected natural gas prices. Firstly, as discussed in Chapter 3, there are key differences between the two regulatory options (both stringency and over time). Second, IPM (and its integrated gas resource and supply module) will develop natural gas reserves and bring to market appropriate natural gas supplies based on a multitude of factors. Since the model simulates perfect foresight, it anticipates future demand for natural gas and respond accordingly. In addition, IPM (and the natural gas module) are viewing a very long time horizon (through 2050, longer than the compliance timeframe), such that the impacts in certain years may be responsive to other modeling assumptions or drivers. The modeling framework is simultaneously solving for all of these key market and policy parameters (both electric and natural gas), resulting in the impacts shown. For more information on the modeling framework see http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev513.html.

Table 5-1. Estimated Percentage Changes in Average Energy Prices, by Energy Type and Regulatory Option

Option 1 Regional Compliance	2020	2025	2030
Electricity Price Change	5.9%	2.7%	2.7%
Delivered Natural Gas Price Change	9.3%	-3.3%	-0.9%
Delivered Coal Price Change	-16.3%	-18.3%	-18.1%
Option 2 Regional Compliance	**2020**	**2025**	**2030**
Electricity Price Change	3.6%	2.4%	n/a
Delivered Natural Gas Price Change	7.5%	0.2%	n/a
Delivered Coal Price Change	-13.8%	-14.4%	n/a
Option 1 State Compliance:	**2020**	**2025**	**2030**
Electricity Price Change	6.5%	2.9%	3.1%
Delivered Natural Gas Price Change	11.5%	-3.5%	0.0%
Delivered Coal Price Change	-16.5%	-17.9%	-18.2%
Option 2 State Compliance	**2020**	**2025**	**2030**
Electricity Price Change	4.0%	2.7%	n/a
Delivered Natural Gas Price Change	8.1%	0.8%	n/a
Delivered Coal Price Change	-13.6%	-14.1%	n/a

For options and years when the price of electricity, natural gas, or coal increased, one would expect decreases in production and increases in market prices in sectors for which these commodities are inputs, ceteris paribus. Conversely, in options and years when prices of these inputs decreased, one would expect increases in production and decreases in market prices within these sectors. Smaller changes in input price changes are assumed to lead to smaller impacts within secondary markets. However, a number of factors in addition to the magnitude and sign of the energy price changes, influence the magnitude of the impact on production and market prices for sectors using electricity, natural gas, or coal as inputs to production. These factors are discussed below.

5.2.1 Share of Total Production Costs

The impact of energy price changes in a particular sector depends, in part, on the share of total production costs attributable to those commodities. For sectors in which the directly affected inputs are only a small portion of production costs, the impact will be smaller than for sectors in which these inputs make up a greater portion of total production costs. Therefore more energy-intensive sectors would potentially experience greater cost increases when electricity, natural gas, or coal prices increase, but would also experience greater savings when these input prices decrease.[123]

5.2.2 Ability to Substitute between Inputs to the Production Process

The ease with which producers are able to substitute other inputs for electricity, natural gas, or coal, or even amongst those commodities, influences the impact of price changes for these inputs. Those sectors with a greater ability to substitute across energy inputs or to other inputs will be able to, at least partially, offset the increased cost of these inputs resulting in smaller market impacts. Similarly, when prices for electricity, natural gas, or coal decrease, some sectors may choose to use more of these inputs in place of other more costly substitutes.

5.2.3 Availability of Substitute Goods and Services

The ability of producers in sectors experiencing changes in their input prices to pass along the increased costs to their customers in the form of higher prices for their products depends, in part, on the availability of substitutes for the sectors' products. Substitutes may either be other domestic products or foreign imports. If close substitutes exist, the demand for the product will in general be more elastic and the producers will be less able to pass on the added cost through a price increase.

Such substitution can also take place between foreign and domestic goods within the same sector. Changes in the price of electricity, natural gas, and coal can influence the quantities of goods imported or exported from sectors using these inputs. When the cost of domestic production increases due to more expensive inputs, imports may increase as consumers substitute towards relatively less costly foreign-produced goods. If imports increase as a result of a regulation and those imports come from countries with fewer emission controls, this can result in foreign emission increases that offset some portion of domestic decreases, an effect commonly referred to as "leakage." The potential for leakage is noteworthy for global pollutants such as carbon dioxide (CO_2) and other GHG emissions. Unlike most criteria pollutants and hazardous air pollutants, the impacts of CO_2 emissions are not affected by the location from which those

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[123] The net direct effect of this rulemaking on the production costs of a sector that is attributable to a change in the electricity price also depends on the expenditures the sector makes to reduce its demand for electricity under any energy efficiency program that was adopted to achieve a state goal. That said, those expenditures may lead to other reduced expenditures for the sector, such as reduced natural gas use from weatherization projects.

emissions originate. EPA does not anticipate significant leakage in the EGU sector to occur from this regulation because the nature of electricity transmission does not lend itself to significant imports or exports of electricity.

5.3 Conclusions

Changes in the price of electricity, natural gas, and coal can impact markets for goods and services produced by sectors that use these energy inputs in the production process. The direction and magnitude of these impacts is influenced by a number of factors. Changes in cost of production may lead to changes in price, quantity produced, and profitability of firms within secondary markets. If regulation results in changes in domestic markets that lead to an increase in imports, increases in production in countries with more energy-intensive production may lead to emissions leakage.

CHAPTER 6: EMPLOYMENT IMPACT ANALYSIS

6.1 Introduction

Executive Order 13563 directs federal agencies to consider regulatory impacts on job creation and employment. According to the Executive Order, "our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science" (Executive Order 13563, 2011). Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts,[124] during periods of sustained high unemployment, employment impacts are of particular concern and questions may arise about their existence and magnitude. The chapter discusses and projects potential employment impacts of the Proposed Electric Generating Unit Greenhouse Gas (EGU GHG) Existing Source Guidelines for the electric power industry, coal and natural gas production, and demand-side energy efficiency.

Section 6.2 presents the overview of the guidelines and a general description of the associated building block framework. Section 6.3 describes the theoretical framework used to analyze regulation-induced employment impacts, discussing how economic theory alone cannot predict whether such impacts are positive or negative. Section 6.4 presents an overview of the peer-reviewed literature relevant to evaluating the effect of environmental regulation on employment. Section 6.5 provides background regarding recent employment trends in the electricity generation, coal and natural gas extraction, renewable energy, and demand-side energy efficiency-related sectors. Section 6.6 presents the EPA's quantitative projections of potential employment impacts in these sectors. These projections are based in part on a detailed model of the electricity production sectors used for this regulatory analysis. Additionally, this section discusses projected employment impacts due to demand-side energy efficiency activities. Section 6.7 offers several conclusions.

[124] Labor expenses do, however, contribute toward total costs in the EPA's standard benefit-cost analyses.

6.2 Overview of the Proposed EGU GHG Existing Source Guidelines

The EPA is proposing emission guidelines for states to use in developing plans to address greenhouse gas emissions from existing fossil fuel-fired EGUs. Specifically, EPA is proposing state-specific rate-based goals for carbon dioxide (CO_2) emissions from the power sector, as well as emission guidelines for states to use in developing plans to attain the state-specific goals. The guidelines, as proposed, will lower carbon intensity of power generation in the United States. Under the Clean Air Act (CAA) section 111(d), state plans must establish standards of performance that reflect the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER) that, taking into account the cost of achieving such reductions and non-air quality health and environmental impact and energy requirements, the Administrator determines has been adequately demonstrated. Consistent with CAA section 111(d), this proposed rule contains state-specific goals that reflect the EPA's calculation of emission reductions that a state can achieve through the cost-effective application of BSER. The EPA is using four building blocks as a basis to determine state-specific goals.

6.2.1 Determining State Goals Utilizing the Four Building Blocks

In proposing state goals, EPA is applying the following four building blocks. Each represents a demonstrated approach to improving the GHG performance of existing EGUs in the power sector:[125]

1. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.
2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including natural gas combined cycle [NGCC] units under construction).

[125] Refer to Chapter 3 for information regarding estimates of emissions reductions achievable by each building block and the determination of state-specific goals.

3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.
4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

6.3 Economic Theory and Employment

Regulatory employment impacts are difficult to disentangle from other economic changes affecting employment decisions over time and across regions and industries. Labor market responses to regulation are complex. They depend on labor demand and supply elasticities and possible labor market imperfections (e.g., wage stickiness, long-term unemployment, etc). The unit of measurement (e.g., number of jobs, types of job hours worked, and earnings) may affect observability of that response. Net employment impacts are composed of a mix of potential declines and gains in different areas of the economy (e.g., the directly regulated sector, upstream and downstream sectors, etc.) over time. In light of these difficulties, economic theory provides a constructive framework for analysis.

Microeconomic theory describes how firms adjust their use of inputs in response to changes in economic conditions.[126] Labor is one of many inputs to production, along with capital, energy, and materials. In competitive markets, firms choose inputs and outputs to maximize profit as a function of market prices and technological constraints.[127,128]

Berman and Bui (2001) and Morgenstern, Pizer, and Shih (2002) adapt this model to analyze how environmental regulations affect labor demand.[129] They model environmental regulation as effectively requiring certain factors of production, such as pollution abatement capital, at levels that firms would not otherwise choose.

[126] See Layard and Walters (1978), a standard microeconomic theory textbook, for a discussion, in Chapter 9.

[127] See Hamermesh (1993), Ch. 2, for a derivation of the firm’s labor demand function from cost-minimization.

[128] In this framework, labor demand is a function of quantity of output and prices (of both outputs and inputs).

[129] Berman and Bui (2001) and Morgenstern, Pizer, and Shih (2002) use a cost-minimization framework, which is a special case of profit-maximization with fixed output quantities.

Berman and Bui (2001, pp. 274-75) model two components that drive changes in firm-level labor demand: output effects and substitution effects.[130] Regulation affects the profit-maximizing quantity of output by changing the marginal cost of production. If regulation causes marginal cost to increase, it will place upward pressure on output prices, leading to a decrease in demand, and resulting in a decrease in production. The output effect describes how, holding labor intensity constant, a decrease in production causes a decrease in labor demand. As noted by Berman and Bui, although many assume that regulation increases marginal cost, it need not be the case. A regulation could induce a firm to upgrade to less polluting and more efficient equipment that lowers marginal production costs. In such a case, output could increase. For example, in the context of the current rule, improving the heat rate of utility boiler increases fuel efficiency, lowering marginal production costs, and thereby potentially increasing the boiler's generation. An unregulated profit-maximizing firm may not have chosen to install such an efficiency-improving technology if the investment cost were too high.

The substitution effect describes how, holding output constant, regulation affects labor-intensity of production. Although increased environmental regulation may increase use of pollution control equipment and energy to operate that equipment, the impact on labor demand is ambiguous. For example, equipment inspection requirements, specialized waste handling, or pollution technologies that alter the production process may affect the number of workers necessary to produce a unit of output. Berman and Bui (2001) model the substitution effect as the effect of regulation on pollution control equipment and expenditures required by the regulation and the corresponding change in labor-intensity of production.

In summary, as output and substitution effects may be positive or negative, theory alone cannot predict the direction of the net effect of regulation on labor demand at the level of the regulated firm. Operating within the bounds of standard economic theory, however, empirical estimation of net employment effects on regulated firms is possible when data and methods of sufficient detail and quality are available. The literature, however, illustrates difficulties with

[130] The authors also discuss a third component, the impact of regulation on factor prices, but conclude that this effect is unlikely to be important for large competitive factor markets, such as labor and capital. Morgenstern, Pizer and Shih (2002) use a very similar model, but they break the employment effect into three parts: 1) a demand effect; 2) a cost effect; and 3) a factor-shift effect.

empirical estimation. For example, studies sometimes rely on confidential plant-level employment data from the U.S. Census Bureau, possibly combined with pollution abatement expenditure data that are too dated to be reliably informative. In addition, the most commonly used empirical methods do not permit estimation of net effects.

The conceptual framework described thus far focused on regulatory effects on plant-level decisions within a regulated industry. Employment impacts at an individual plant do not necessarily represent impacts for the sector as a whole. The approach must be modified when applied at the industry level.

At the industry-level, labor demand is more responsive if: (1) the price elasticity of demand for the product is high, (2) other factors of production can be easily substituted for labor, (3) the supply of other factors is highly elastic, or (4) labor costs are a large share of total production costs.[131] For example, if all firms in an industry are faced with the same regulatory compliance costs and product demand is inelastic, then industry output may not change much, and output of individual firms may change slightly.[132] In this case, the output effect may be small, while the substitution effect depends on input substitutability. Suppose, for example, that new equipment for heat rate improvements requires labor to install and operate. In this case, the substitution effect may be positive, and with a small output effect, the total effect may be positive. As with potential effects for an individual firm, theory cannot determine the sign or magnitude of industry-level regulatory effects on labor demand. Determining these signs and magnitudes requires additional sector-specific empirical study. For environmental rules, much of the data needed for these empirical studies is not publicly available, would require significant time and resources in order to access confidential U.S. Census data for research, and also would not be necessary for other components of a typical Regulatory Impact Analysis (RIA).

In addition to changes to labor demand in the regulated industry, net employment impacts encompass changes in other related sectors. For example, the proposed guidelines may increase demand for heat rate improving equipment and services. This increased demand may increase

[131] See Ehrenberg & Smith, p. 108.

[132] This discussion draws from Berman and Bui (2001), pp. 293.

revenue and employment in the firms supporting this technology. At the same time, the regulated industry is purchasing the equipment, and these costs may impact labor demand at regulated firms. Therefore, it is important to consider the net effect of compliance actions on employment across multiple sectors or industries.

If the U.S. economy is at full employment, even a large-scale environmental regulation is unlikely to have a noticeable impact on aggregate net employment.[133] Instead, labor would primarily be reallocated from one productive use to another (e.g., from producing electricity or steel to producing high efficiency equipment), and net national employment effects from environmental regulation would be small and transitory (e.g., as workers move from one job to another).[134]

Affected sectors may experience transitory effects as workers change jobs. Some workers may retrain or relocate in anticipation of new requirements or require time to search for new jobs, while shortages in some sectors or regions could bid up wages to attract workers. These adjustment costs can lead to local labor disruptions. Although the net change in the national workforce is expected to be small, localized reductions in employment may adversely impact individuals and communities just as localized increases may have positive impacts.

If the economy is operating at less than full employment, economic theory does not clearly indicate the direction or magnitude of the net impact of environmental regulation on employment; it could cause either a short-run net increase or short-run net decrease (Schmalansee and Stavins, 2011). An important research question is how to accommodate unemployment as a structural feature in economic models. This feature may be important in assessing large-scale regulatory impacts on employment (Smith, 2012).

Environmental regulation may also affect labor supply. In particular, pollution and other environmental risks may impact labor productivity or employees' ability to work.[135] While the

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[133] Full employment is a conceptual target for the economy where everyone who wants to work and is available to do so at prevailing wages is actively employed. The unemployment rate at full employment is not zero.

[134] Arrow et al. 1996; see discussion on bottom of p. 8. In practice, distributional impacts on individual workers can be important, as discussed in later paragraphs of this section.

[135] E.g. Graff Zivin and Neidell (2012).

theoretical framework for analyzing labor supply effects is analogous to that for labor demand, it is more difficult to study empirically. There is a small emerging literature described in the next section that uses detailed labor and environmental data to assess these impacts.

To summarize, economic theory provides a framework for analyzing the impacts of environmental regulation on employment. The net employment effect incorporates expected employment changes (both positive and negative) in the regulated sector and elsewhere. Labor demand impacts for regulated firms, and also for the regulated industry, can be decomposed into output and substitution effects which may be either negative or positive. Estimation of net employment effects for regulated sectors is possible when data of sufficient detail and quality are available. Finally, economic theory suggests that labor supply effects are also possible. In the next section, we discuss the empirical literature.

6.4 Current State of Knowledge Based on the Peer-Reviewed Literature

The labor economics literature contains an extensive body of peer-reviewed empirical work analyzing various aspects of labor demand, relying on the theoretical framework discussed in the preceding section.[136] This work focuses primarily on effects of employment policies such as labor taxes and minimum wages.[137] In contrast, the peer-reviewed empirical literature specifically estimating employment effects of environmental regulations is more limited.

Empirical studies, such as Berman and Bui (2001), suggest that net employment impacts were not statistically different from zero in the regulated sector. Other research suggests that more highly regulated counties may generate fewer jobs than less regulated ones (Greenstone, 2002). Environmental regulations may affect sectors that support pollution reduction earlier than the regulated industry. Rules are usually announced well in advance of their effective dates and then typically provide a period of time for firms to invest in technologies and process changes to meet the new requirements. When a regulation is promulgated, the initial response of firms is often to order pollution control equipment and services to enable compliance when the regulation

[136] Again, see Hamermesh (1993) for a detailed treatment.

[137] See Ehrenberg & Smith (2000), Chapter 4: “Employment Effects: Empirical Estimates” for a concise overview.

becomes effective. Estimates of short-term increases in demand for specialized labor within the environmental protection sector have been prepared for several EPA regulations in the past, including the Mercury and Air Toxics Standards (MATS).[138] Overall, the peer-reviewed literature does not contain evidence that environmental regulation has a large impact on net employment (either negative or positive) in the long run across the whole economy.

6.4.1 Regulated Sector

Berman and Bui (2001) examine how an increase in local air quality regulation affects manufacturing employment in the South Coast Air Quality Management District (SCAQMD), which includes Los Angeles and its suburbs. From 1979 to 1992, the SCAQMD enacted some of the country's most stringent air quality regulations. Using SCAQMD's local air quality regulations, Berman and Bui identify the effect of environmental regulations on net employment in regulated manufacturing industries relative to other plants in the same 4-digit standard industrial classification (SIC) industries but in regions not subject to local regulations.[139] The authors find that "while regulations do impose large costs, they have a limited effect on employment" (Berman and Bui, 2001, p. 269). Their conclusion is that local air quality regulation "probably increased labor demand slightly" but that "the employment effects of both compliance and increased stringency are fairly precisely estimated zeros, even when exit and dissuaded entry effects are included" (Berman and Bui, 2001, p. 269).[140]

The few studies in peer-reviewed journals evaluating employment impacts of policies that reduce CO_2 emissions in the electric power generation sector are in the European context. In a sample of 419 German firms, 13 percent of which were in the electricity sector, Anger and Oberndorfer (2008) find that the initial allocation of emission permits did not significantly affect employment growth in the first year of the Eurpoean Union (EU) Emissions Trading Scheme (ETS). Examining European firms from 1996-2007, Commins et al. (2011) find that a 1 percent

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[138] U.S. EPA (2011b).

[139] Berman and Bui include over 40 4-digit SIC industries in their sample. They do not estimate the number of jobs created in the environmental protection sector.

[140] Including the employment effect of existing plants and plants dissuaded from opening will increase the estimated impact of regulation on employment.

increase in energy taxes is associated with a 0.01 percent decrease in employees in the electricity and gas sector. Chan et al. (2013) estimate the impact of the EU ETS on a panel of almost 6,000 firms in 10 European countries from 2005-2009. They find that firms in the power sector that participated in the ETS had 2-3 percent fewer employees relative to those that did not participate, but this effect is not statistically significant.

This literature suggests that the employment impacts of controlling CO_2 emissions in the European power sector were small. The degree to which these studies' results apply to the U.S. context is unclear. European policies analyzed in these studies effectively put a price on emissions either through taxes or tradable permits. A performance standard may not generate similar employment effects. Moreover, European firms face relative fuel prices and market regulatory structures different from their U.S. counterparts, further complicating attempts to transfer quantitative results from the EU experience to evaluate this rule.

A small literature examines impacts of environmental regulations on manufacturing employment. Kahn and Mansur (2013) study environmental regulatory impacts on geographic distribution of manufacturing employment, controlling for electricity prices and labor regulation (right to work laws). Their methodology identifies employment impacts by focusing on neighboring counties with different air quality regulations. They find limited evidence that environmental regulations may cause employment to be lower within "county-border-pairs." This result suggests that regulation may cause an effective relocation of labor across a county border, but since one county's loss is another's gain, such shifts cannot be transformed into an estimate of a national net effect on employment. Moreover this result is sensitive to model specification choices.

6.4.2 Labor Supply Impacts

The empirical literature on environmental regulatory employment impacts focuses primarily on labor demand. However, there is a nascent literature focusing on regulation-induced effects on labor supply.[141] Although this literature is limited by empirical challenges, researchers

[141] For a recent review see Graff-Zivin and Neidell (2013).

have found that air quality improvements lead to reductions in lost work days (e.g., Ostro, 1987). Limited evidence suggests worker productivity may also improve when pollution is reduced. Graff Zivin and Neidell (2012) used detailed worker-level productivity data from 2009 and 2010, paired with local ozone air quality monitoring data for one large California farm growing multiple crops, with a piece-rate payment structure. Their quasi-experimental structure identifies an effect of daily variation in monitored ozone levels on productivity. They find "ozone levels well below federal air quality standards have a significant impact on productivity: a 10 parts per billion (ppb) decreases in ozone concentrations increases worker productivity by 5.5 percent." (Graff Zivin and Neidell, 2012, p. 3654).[142]

This section has outlined the challenges associated with estimating regulatory effects on both labor demand and supply for specific sectors. These challenges make it difficult to estimate net national employment estimates that would appropriately capture the way in which costs, compliance spending, and environmental benefits propagate through the macro-economy. Quantitative estimates are further complicated by the fact that macroeconomic models often have little sectoral detail and usually assume that the economy is at full employment. The EPA is currently seeking input from an independent expert panel on modeling economy-wide regulatory impacts, including employment effects.[143]

6.5 Recent Employment Trends

The U.S. electricity system includes employees that support electric power generation, transmission and distribution; the extraction of fossil fuels; renewable energy generation; and supply-side and demand-side energy efficiency. This section describes recent employment trends in the electricity system.

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[142] The EPA is not quantifying productivity impacts of reduced pollution in this rulemaking using this study. In light of this recent research, however, the EPA is considering how best to incorporate possible productivity effects in the future.

[143] For further information see: <https://www.federalregister.gov/articles/2014/02/05/2014-02471/draft-supporting-materials-for-the-science-advisory-board-panel-on-the-role-of-economy-wide-modeling>.

6.5.1 Electric Power Generation

In 2013, the electric power generation, transmission and distribution sector (NAICS 2211) employed 394,000 workers in the U.S.[144] Installation, maintenance, and repair occupations accounted for the largest share of workers (30 percent).[145] These categories include inspection, testing, repairing and maintaining of electrical equipment and/or installation and repair of cables used in electrical power and distribution systems. Other major occupation categories include office and administrative support (17 percent), production occupations (15 percent), architecture and engineering (11 percent), business and financial operations (7 percent) and management (6 percent).

As shown in Figure 6.1, employment in the Electric Power Industry averaged 435,000 workers in the early 2000s, declining to an average of 400,000 workers later in the decade, and to 394,000 workers in 2013.

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[144] U.S. Bureau of Labor Statistics. "Current Employment Survey Seasonally Adjusted Employment for Electric Power Generation, Transmission, and Distribution (national employment)." Series ID: CES4422110001. Data extracted on: February 19, 2014. Available at: <http://www.bls.gov/ces/data.htm>.

[145] U.S. Bureau of Labor Statistics, Occupational Employment Statistics, May 2012 National Industry-Specific Occupational Employment and Wage Estimates, Electric Power Generation, Transmission, and Distribution (NAICS 2211). Available at: <http://www.bls.gov/oes/current/naics4_221100.htm>.

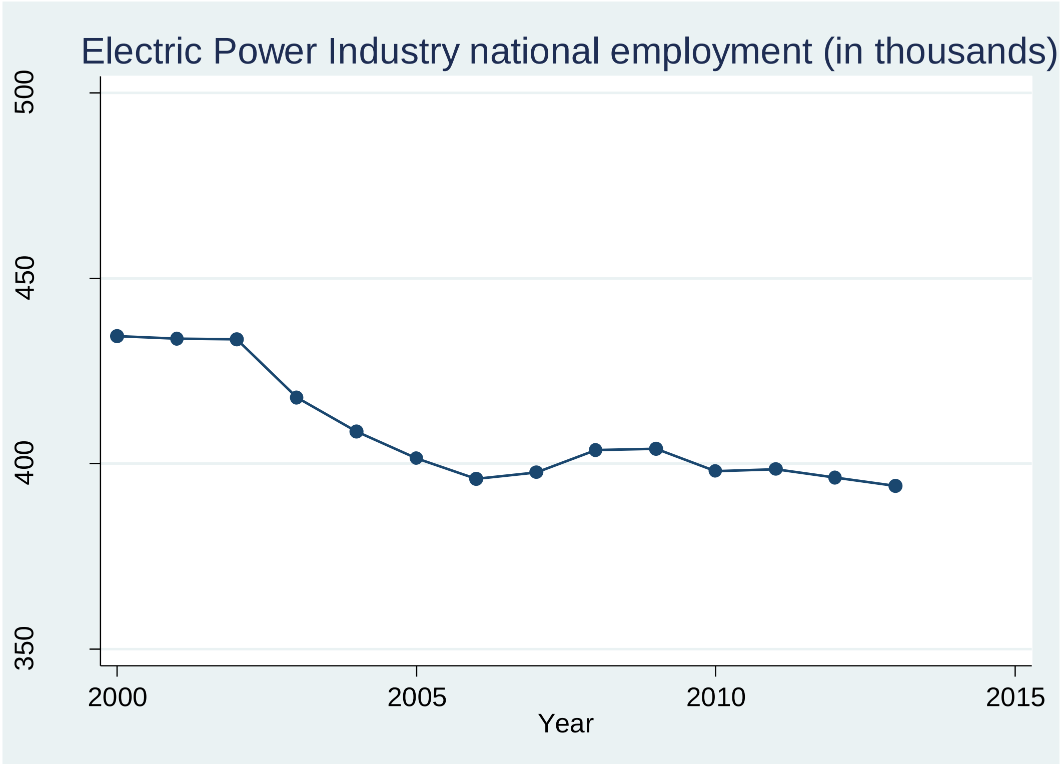

Figure 6.1. Electric Power Industry Employment

6.5.2 Fossil Fuel Extraction

6.5.2.1 Coal Extraction

The coal extraction sector is primarily engaged in coal mining and coal mine site development, excluding metal ore mining and nonmetallic mineral mining and quarrying. There are two sources of U.S. government data on coal mining employment, the Bureau of Labor Statistics (BLS) Current Employment Statistics (NAICS 2121), and the Department of Labor's Mine Safety and Health Administration (MSHA).[146] Both sources show similar national levels and trends, though one is survey-based (BLS) and the other is census-based (MSHA). MSHA tracks direct coal mine employment and independent contractor employment, whereas BLS does

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[146] U.S. Bureau of Labor Statistics. "Current Employment Statistics Seasonally Adjusted Employment for Coal Mining (national employment)," NAICS 2121, Series ID: CES1021210001. Data extracted on: February 19, 2014. Available at: < http://www.bls.gov/ces/data.htm>.

not track contractors. Contractor employment reported by MSHA focuses primarily on mine development, construction, reconstruction or demolition of mine facilities, construction of dams, excavation or earth moving, equipment installation, service or repair, and material handling, drilling, or blasting.[147] In 2013, BLS reported 79,000 coal mining employees, and MSHA reported 80,000 coal mining employees and 32,000 contractors.[148] Both sets of data reveal a stable trend in employment over the past 10 years, with the exception of a small temporary increase in 2011. See Figure 6.2 below.

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[147] Mine Safety and Health Administration, CFR Part 50 Title 30 Employment Data – selected contract employment is included, p. 2. Available at: <http://www.msha.gov/Stats/Part50/WQ/MasterFiles/MIWQ%20Master_20133.pdf>. U.S. Bureau of Labor Statistics, Current Employment Statistics – contract employment not included. Available at: <http://www.bls.gov/ces/idcf/forme_sp.pdf>.

[148] Annual averages calculated for: (i) BLS monthly coal mining employment data for 2013, and (ii) MSHA Part 50 quarterly data for 2013. Available at: <http://www.msha.gov/STATS/PART50/P50Y2K/AETABLE.HTM>.

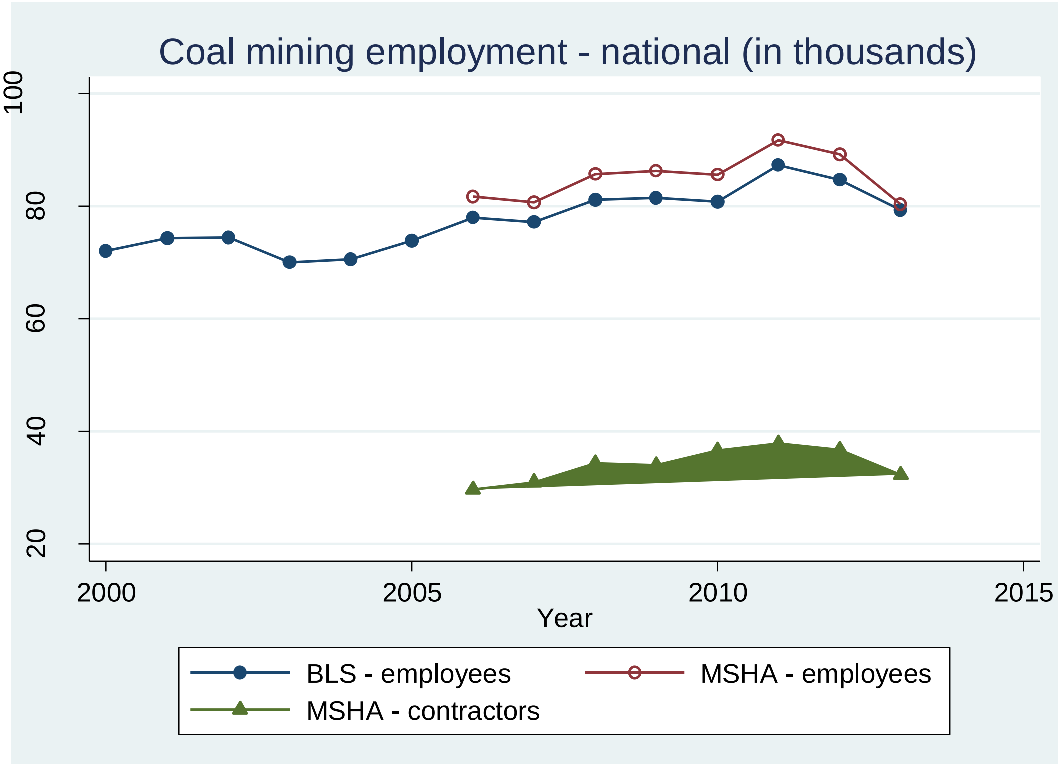

Figure 6.2. Coal Production Employment

6.5.2.2 Oil and Gas Extraction

In 2013, there were 198,000 employees in the oil and gas extraction sector (NAICS 211).[149] This sector includes production of crude petroleum, oil from oil shale and oil sands, production of natural gas, sulfur recovery from natural gas, and recovery of hydrocarbon liquids. Activities include the development of gas and oil fields, exploration activities for crude petroleum and natural gas, drilling, completing, and equipping wells, and other production activities.[150] In contrast with coal, and looking at Figure 6.3, there has been a sharp increase in employment in this sector over the past decade.

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[149] BLS, Current Employment Statistics. Seasonally adjusted employment for oil and gas extraction (national employment), NAICS 211. Series ID: CES1021100001. Data extracted on: February 19, 2014. Available at: <http://www.bls.gov/ces/data.htm

[150] U.S. Bureau of Labor Statistics. 20014. Available at: <http://www.bls.gov/iag/tgs/iag211.htm Accessed Feb. 19>.

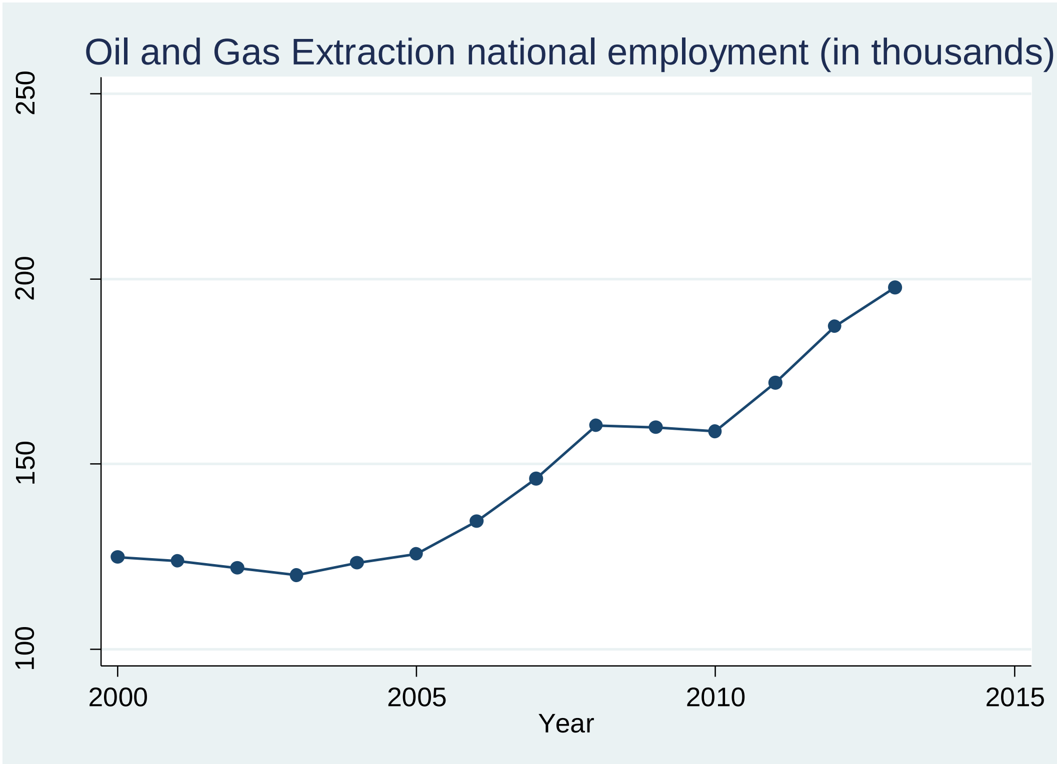

Figure 6.3. Oil and Gas Production Employment

6.5.3 Clean Energy Employment Trends

Clean energy resources, such as energy efficiency and renewable energy, are used to meet energy demand, reduce peak electricity system loads, and reduce reliance on the most carbon-intensive sources of electricity. However, there is not a single clean energy sector in standard national accounts classifications. Renewable generation is not reported to the BLS separately from other electric power generation. Similarly, manufacturers of energy efficient appliances are not reported separately from conventional appliance manufacturers and green building design is not separate from the construction sector. Instead, clean energy technology and services are supported by industries throughout the economy.

Without a specific industrial classification, it is difficult to quantify the exact number of clean energy-related jobs or document the trends. Employees engaged in clean energy can span many job classifications, such as experts required to design and produce a renewable or energy-efficient technology, workers that supply inputs and technicians who install service or operate equipment. As such, there are a variety of definitions of clean or green jobs used, some more expansive than others.

6.5.3.1 Defining Clean Energy Jobs

Two U.S. Government sources, the 2010 Department of Commerce (DOC) report, *Measuring the Green Economy* and the 2010 and 2011 BLS *Green Goods and Services* surveys have subdivided industrial classifications into "green" categories. In both cases the approach was to determine which product classifications, rather than industries, were green. They multiplied green production by product revenue and defined an industrial sector as green if it met a threshold of green revenue as a proportion of total revenue.

DOC broadly defined green jobs in 2010 as those "created and supported in businesses that produce green products and services."[151] They further classified green jobs into a broad and a narrow category. The narrow category includes only products deemed to be green without disagreement, while the broad category is more inclusive definition of green goods and services to over 22,000 product codes in the 2007 Economic Census to estimate their contribution to the U.S. economy. The report found that the number of green jobs in 2007 ranged from 1.8 million to 2.4 million jobs, accounting for between 1.5 and 2 percent of total private sector employment.[152]

BLS used an expansive definition of clean or green jobs in 2010 and 2011. It goes beyond direct clean energy-related investments and includes "those in businesses that produce goods and provide services that benefit the environment or conserve natural resources. These goods and services, which are sold to customers, include research and development, installation, and maintenance services for renewable energy and energy efficiency and education and training related to green technologies and practices" but also include recycling and natural resource

[151] U.S. Department of Commerce Economics and Statistics Administration. 2010. "Measuring the Green Economy," April. Available at: <http://www.esa.doc.gov/sites/default/files/reports/documents/greeneconomyreport_0.pdf>.

[152] U.S. Department of Commerce Economics and Statistics Administration. 2010. "Measuring the Green Economy, April. Available at: <http://www.esa.doc.gov/sites/default/files/reports/documents/greeneconomyreport_0.pdf>.

conservation, such as forestry management.[153] Based on surveys across the 325 industries it identified as potential producers of green goods and services, BLS counts approximately 2.3 million jobs in the green economy in 2010, rising 7.4 percent to 2.5 million in 2011,[154] compared to increases of about one percent across all occupations in the entire economy over the same period.[155] The table below, Table 6-1, presents BLS green job estimates nationally and for the utility sector.

Table 6-1. U. S. Green Goods and Services (GGS) Employment (annual average)

	Total GGS Employment	Utility GGS Employment	Total GGS Growth 2010-11	Utility GGS Growth 2010-11
2010	2,342,562	69,031	NA	NA
2011	2,515,200	71,129	7.4%	3.0%

Source: Bureau of Labor Statistics

6.5.3.2 Renewable Electricity Generation Employment Trends

The DOC report does not separate renewable energy data and the BLS data include only privately owned electricity generating facilities. As such, neither source isolates renewable electricity generation employment. For historical trends in this sector, we therefore, rely on a Brookings Institution study, Muro et al. (2011). This study built a national database of "clean economy" jobs from the bottom up, verifying each company individually.[156] They include a list of categories similar but not identical to that of BLS, including agricultural and natural resources conservation, education and compliance, energy and resource efficiency, greenhouse gas reduction, environmental management and recycling, and renewable energy. This study found about 138,000 jobs in the renewable energy sector in 2010, with an overall average annual growth rate of 3.1 percent from 2003-2010. Table 6-2 details the national results by energy

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153 BLS has identified 325 detailed industries (6-digit NAICS) as potential producers of green goods and services. Available at: <http://www.bls.gov/ggs/ggsoverview.htm>. (Accessed on 1-14-14, l**ast modified date:** March 19, 2013.

154 U.S. Department of Labor, U.S. Bureau of Labor Statistics. (n.d.). 2011. "Green Goods and Services 2010-2011." (Retrieved on January 14, 2014). Available at :< http://www.bls.gov/ggs/ggsoverview.htm>.

155 U.S. Department of Labor, U.S. Bureau of Labor Statistics. 2010. National Occupational Employment and Wage Estimates, United States. Available at: <http://www.bls.gov/oes/2010/may/oes_nat.htm>, May. National Occupational Employment and Wage Estimates, United States http://www.bls.gov/oes/2010/may/oes_nat.htm.

156 <http://www.brookings.edu/~/media/Series/resources/0713_clean_economy.pdf> p. 15.

source.

Table 6-2. Renewable Electricity Generation-Related Employment

Sector	Jobs, 2010	2003-2010 Average Annual Growth Rate (%)
Biofuels/Biomass	20,680	8.9
Geothermal	2,720	6.7
Hydropower	55,467	-3.6
Renewable Energy Services	1,981	6.3
Solar Photovoltaic	24,152	10.7
Solar Thermal	5,379	18.4
Waste-to-Energy	3,320	3.7
Wave/Ocean Power	371	20.9
Wind	24,294	14.9
Total	138,364	3.1

Source: http://www.brookings.edu/~/media/Series/resources/0713_clean_economy.pdf, Appendix A.

6.5.3.3 Employment Trends in Demand-Side Energy Efficiency Activities

U.S. government data used for calculating the historical trends in the demand-side energy efficiency sector come from the BLS green goods and services surveys. BLS reports an energy efficiency category, finding 1.49 million private sector energy efficiency jobs in 2010 and 1.64 million in 2011.

For a longer term trend the Brookings Institution study (Muro et al., 2011) built a national database of "clean economy" jobs from the bottom up, verifying each company individually.[157] This study found about 428,000 jobs in the Energy and Resource Efficiency sector in 2010, with an overall average annual growth rate of 2.6 percent from 2003-2010. Table 6-3 details the results by energy sector.

[157] <http://www.brookings.edu/~/media/Series/resources/0713_clean_economy.pdf> p. 15

Table 6-3. Energy and Resources Efficiency-Related Employment

Sector	Jobs, 2010	2003-2010 Average Annual Growth Rate (%)
Appliances	36,608	-3.1
Energy-saving Building Materials	161,896	2.5
Energy-saving Consumer Products	19,210	-2.9
Green Architecture and Construction Services	56,190	6.4
HVAC and Building Control Systems	73,600	3.3
Lighting	14,298	-1.8
Professional Energy Services	49,863	6.9
Smart Grid	15,987	8.6
Total	427,652	2.6

Source: http://www.brookings.edu/~/media/Series/resources/0713_clean_economy.pdf, Appendix A

In addition, other research institutes and industry groups have clean economy or clean energy employment databases. While definitions and timeframes vary, all show positive employment trends of 1.9 percent or more growth in clean energy-related jobs annually.

6.6 Projected Sectoral Employment Changes due to Proposed Guidelines

EGUs may respond to these proposed guidelines by placing new orders for efficiency-related or renewable energy equipment and services to reduce GHG emissions. Installing and operating new equipment or improving heat rate efficiency could increase labor demand in the electricity generating sector itself, as well as associated equipment and services sectors. Specifically, the direct employment effects of supply-side initiatives include changes in labor demand for manufacturing, installing, and operating higher efficiency or renewable energy electricity generating assets supported by the initiative while reducing the demand for labor that would have been used by less efficient or higher emitting generating assets. Once implemented, increases in operating efficiency would impact the power sector's demand for fuel and plans for EGU retirement and new construction.

In addition, EPA expects state compliance plans to also include demand-side energy efficiency policies and programs that typically change energy consumption patterns of business and residential consumers by reducing the quantity of energy required for a given level of production or service. Demand-side initiatives generally aim to increase the use of cost-effective energy efficiency technologies (e.g., including more efficient appliances and air conditioning systems, more efficient lighting devices, more efficient design and construction of new homes and businesses), and advance efficiency improvements in motor systems and other industrial processes. Demand-side initiatives can also directly reduce energy consumption, such as through programs encouraging changing the thermostat during the hours a building is unoccupied or motion-detecting room light switches. Such demand-side energy efficiency initiatives directly affect employment by encouraging firms and consumers to shift to more efficient products and processes than would otherwise be the case. Employment in the sectors that provide these more efficient devices and services would be expected to increase, while employment in the sectors that produce less efficient devices would be expected to contract.

This analysis uses the cost projections from the engineering-based Integrated Planning Model (IPM) to project labor demand impacts of the proposed guidelines for the electricity generation sector (fossil, renewable, and nuclear), and the fuel production sector (coal and natural gas). These projections include effects attributable to heat rate improvements, construction of new EGUs, changes in fuel use, and reductions in electricity generation due to demand-side energy efficiency activities. To project labor requirements for demand-side energy efficiency activities, the analysis uses a different approach that combines data on historic changes in employment and expenditures in the energy efficiency sector with projected changes in expenditures in the sector arising from state implementation of the proposed guidelines.

We project labor impacts for two options for establishing the "best system of emission reduction" (BSER) for GHG emissions from existing EGUs. The EPA is proposing a BSER goal approach referred to as Option 1 and taking comment on a second approach referred to as Option 2. Each of these goal approaches use the four building blocks described above at different levels of stringency. Option 1 involves higher deployment of the four building blocks but allows a longer timeframe to comply (2030) whereas Option 2 has a lower deployment over a shorter timeframe (2025). This analysis estimates labor impacts of illustrative state and regional compliance approaches for the goals set for Options 1 and 2. With the state compliance approach, states are assumed to comply with the guidelines by implementing measures solely within the state and emissions rate averaging occurs between affected sources on an intrastate basis only. In contrast under the regional approach, groups of states are assumed to collaboratively comply with the guidelines.

6.6.1 Projected Changes in Employment in Electricity Generation and Fossil Fuel Extraction

The analytical approach used in this analysis is a bottom-up engineering method combining EPA's cost analysis of the proposed guidelines with data on labor productivity, engineering estimates of the amount and types of labor needed to manufacture, construct, and operate different types of generating units, and prevailing wage rates for skilled and general labor categories. This approach is different from the types of economic analyses discussed in section 6.3. Rather than projecting employment impacts throughout the U.S. economy, the engineering-based analysis focuses on the direct impact on labor demand in industries closely involved with electricity generation. The engineering approach projects labor changes measured as the change in each analysis year in job-years[158] employed in the power generation and directly related sectors (e.g., equipment manufacturing, fuel supply and generating efficiency services). For example, this approach projects the amounts and types of labor required to implement improvements in generating efficiency. It then uses the EPA's estimated effect of efficiency improvements on fuel demand to project reductions in the amount of labor required to produce coal and gas.

This analysis relies on projections and costing analysis from the IPM, which uses industry-specific data and assumptions to estimate costs and energy impacts of the proposed guidelines (see Chapter 3). The EPA uses the IPM to predict coal generating capacity that is likely to undertake improvements in heat rate efficiency (HRI).[159] IPM also predicts the guidelines' impacts on fuel use, retirement of existing units, and construction of new ones.

The methods we use to estimate the labor impacts are based on the analytical methods used in the Regulatory Impact Analysis for the Mercury and Air Toxics Standards (MATS). While the methods used in this analysis to estimate the recurring labor impacts (e.g., labor associated with operating and maintaining generating units, as well as labor needed to mine coal

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[158] Job-years are not individual jobs, but rather the amount of work performed by the equivalent of one full-time individual for one year. For example, 20 job-years in 2020 may represent 20 full-time jobs or 40 half-time jobs in that year.

[159] Heat rate improvements (HRI) could include a range of activities in the power plant to lower the heat rate required to generate a net electrical output. Assuming all other things being equal, a lower heat rate is more efficient because more electricity is generated from each ton of coal.

and natural gas) are the same as we used in MATS (with updated data where available), the methods used to estimate the labor associated with installing new capacity and implementing heat rate improvements were developed for the GHG guidelines analysis.

The bottom-up engineering-based labor analysis in the MATS RIA primarily was concerned with the labor needs of retrofitting pollution control equipment. A central feature of the GHG guidelines labor analysis, however, involves the quantity and timing of the labor needs of building new renewable (primarily wind) and NGCC generating capacity. The EPA IPM analysis finds that by 2020 a significantly larger amount of renewable and NGCC capacity will be built to implement the GHG guidelines under all of the option scenarios. For example, in the base case IPM estimates that 11 GW of non-hydro renewable capacity will be built between 2016 and 2020, while under Option 1 with regional compliance almost twice as much (21.3 GW) renewable capacity will be built. Similarly, in the base case 7.9 GW of NGCC capacity is built between 2016 and 2020, while almost 3 times as much (24.43 GW) is built under Option 1 with regional compliance.

An important aspect of building new units is that all of the construction-related labor occurs before the new units become operational. While the financial costs of building the new units are amortized and recouped over the book life of the new equipment, the labor involved with manufacturing equipment and constructing the new units occurs, and is actually paid for, in a concentrated amount of time before the new capacity begins to generate electricity. IPM assumes[160] that new NGCC units take 3 years to build, and both natural gas combustion turbines and wind-powered renewables take 2 years.

In addition to the amount of labor needed to build new generating capacity, IPM also estimates that there will be significant labor impacts in later years from avoiding having to build additional new capacity. Because of the demand-side energy efficiency programs, the total amount of electricity needed by 2030 is substantially lower with all of the Options than in the base case. For example, in Option 1 with regional compliance only half the total new NGCC capacity is built between 2016 and 2030 (40.6 GW), compared with 79.7 GW in the base case.

[160] Table 4.7, IPM 5.13 Documentation.

The avoided new capacity results in both a significant net cost savings to consumers and the power sector, as well reduced emissions of both CO_2 and precursor pollutants from fossil fuel generation. The avoided new capacity, however, also has significant labor impacts. A portion of the employment that would have been used to build the new capacity in the base case will not occur with the implementation of the GHG guidelines. Similarly, less labor involved with operating and providing fuel for new units will be needed with the GHG guidelines than in the base case.

Overall, the impact of much more rapid construction of new renewable and fossil generation capacity in the early years of implementing the GHG guidelines, followed by the need to build substantially less capacity in later years as the demand-side energy efficiency programs reduce the overall electricity demand relative to the base case, creates an important but complex temporal dynamic to the supply-side labor analysis. In the early years of implementation there will be a sizable net increase in the amount of labor needed to construct and operate the new generating capacity. However, in later years, the reduced need for additional newly built capacity results in a sizable net decrease in the amount of labor needed relative to the base case.

The changes in the timing and overall need for new capacity have direct labor impacts not only on the construction-related one-time labor, but also on the subsequent needs for operating and fuel supply labor to operate the plants. In the case of avoided new capacity, the labor impacts include the loss of those ongoing labor needs. In addition, there are similar labor impacts from the loss of operating and fuel-related jobs arising from the retirement of existing coal generating capacity.

A critical component of the overall labor impacts of implementing the GHG guidelines is the impact of the labor associated with the demand-side energy efficiency activities. The demand-side labor impacts are presented in section 6.6.2. All of the labor impacts of the demand-side energy efficiency activities are increases in labor needs, which more than offset the loss of supply-side jobs associated with the decreasing demand for electricity arising from the demand-side programs. The IPM labor expenditure projections are distributed across different labor categories (e.g., general construction labor, boilermakers and engineering) using data from engineering analyses of labor's overall share of total expenditures, and apportionment of total labor cost to various labor categories. Hourly labor expenditures (including wages, fringe benefits, and employer-paid costs including taxes, insurance and administrative costs) for each category are used to estimate the labor quantity (measured in full-time job-years) consistent with the compliance scenario projections. Projected labor impacts arising from changes in fuel demand are primarily derived from labor productivity data for coal mining (tons mined per employee hour) and natural gas extraction (MMBtu produced/job-year). Tables 6.4 and 6.5 present projected changes relative to the baseline of four labor categories:

1. manufacturing, engineering and construction for building, designing and implementing heat rate improvements;
2. manufacturing and construction for new generating capacity;
3. operating and maintenance for existing generating capacity; and
4. extraction of coal and natural gas fuel.

All of the employment estimates presented in Tables 6-4 and 6-5 are estimates occurring in a single year. For the construction-related (one-time) labor impacts, including the installation of HRI, Tables 6-4 and 6-5 present the average annual impact occurring in each year of three different intervals of years. The multi-year intervals correspond with the analytical years reported by IPM. The three intervals are from 2017 through 2020 (a four year interval), from 2021 through 2025 (five years), and 2026 through 2030 (5 years). The construction-related labor analysis are based on the IPM estimates of the net change in capital investment that occurs during each multi-year interval to fund building new units completed during that interval. The new build labor analysis uses the net change in capital investment to estimate the amount and type of labor needed during the interval to build the new capacity. The analysis assumes that the new built labor within each interval is evenly distributed throughout the interval. Tables 6-4 and 6-5 reflect this assumption by presenting the average labor utilization per year during each of the three intervals.

The HRI-related labor impacts are estimated based on the assumed capital cost of \$100/kw (see section 3.7.3). Note that all of the HRI-related labor impacts occur in the first interval (2017 to 2020), and are assumed to be occur evenly throughout that four year interval. Therefore, the HRI-related labor estimates in Tables 6-4 and 6-5 are the annual average labor impacts for of the four years. There are no HRI improvements made after 2020.

The labor estimates for operating and maintaining generating units annually are based on IPMs estimates of Fixed Operating and Maintenance (FOM) Costs. IPM estimates FOM for each year individually, so the net changes in O&M-related labor estimates in Tables 6-4 and 6-5 are single year estimates for 2020, 2025 and 2030. These O&M labor estimates are not the average annual averages labor needs throughout each multi-year interval. There are O&M labor changes occurring in the all years throughout the entire period 2017-2030, but labor impact changes each year. The fuel-related labor estimates are also single-year estimates, and not multi-year averages. The labor analysis uses IPM's estimates of the net changes in the amount of coal and natural gas in 2020, 2025 and 2030, which are inherently estimates of the fuel usage in a single year. As with the O&M labor impacts, the fuels-related labor impacts occur in every year throughout 2017-2030, and the labor impact changes every year.

It should be noted that the supply-side labor impact estimates in Tables 6-4 and 6-5 reflect all the supply-side changes that will occur with each alternative option and compliance alternative. These labor impacts include not only the impacts of Building Blocks 1 through 3, but also the changes in total generation needed that result from the demand-side energy efficiency activities in Building Block 4. The additional upstream labor impacts from the demand-side activities are presented below in section 6.2.2.

More details on methodology, assumptions, and data sources used to estimate the supply-side labor impacts discussed in this section can be found in Appendix 6A.

Table 6-4. Engineering-Based[a] Changes in Labor Utilization, Regional Compliance Approach - (Number of Job-Years[b] of Employment in a Single Year)

Category	Option 1			Option 2		
Construction-related (One-time) Changes*						
	2017-2020	**2021-2025**	**2026-2030**	**2017-2020**	**2021-2025**	**2026-2030**
Heat Rate Improvement: Total	**32,900**	**0**	**0**	**33,900**	**0**	**n/a**
Boilermakers and General Construction	22,800	0	0	23,600	0	n/a
Engineering and Management	6,000	0	0	6,200	0	n/a
Equipment-related	2,900	0	0	3,000	0	n/a
Material-related	1,100	0	0	1,100	0	n/a
New Capacity Construction: Total	**24,700**	**-33,300**	**-37,000**	**14,700**	**-23,100**	**n/a**
Renewables	17,000	-4,700	-2,100	11,600	-3,100	n/a
Natural Gas	7,700	-28,600	-34,900	3,100	-20,000	n/a
Recurring Changes**						
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
Operation and Maintenance: Total	**-22,900**	**-23,800**	**-23,700**	**-15,300**	**-15,500**	**n/a**
Changes in Gas	2,300	-600	-3,400	1,000	-1,000	n/a
Retired Coal	-22,600	-20,800	-18,200	-14,600	-13,100	n/a
Retired Oil and Gas	-2,600	-2,400	-2,100	-1,700	-1,400	n/a
Fuel Extraction: Total	**-8,800**	**-14,900**	**-19,200**	**-6,600**	**-10,600**	**n/a**
Coal	-13,700	-17,000	-16,600	-10,900	-12,900	n/a
Natural Gas	4,900	2,100	-2,600	4,300	2,300	n/a
Supply-Side Employment Impacts - Quantified	**25,900**	**-72,000**	**-79,900**	**26,700**	**-49,200**	**n/a**

[a] Job-year estimates are derived from IPM investment and O&M cost estimates, as well as IPM fuel use estimates (tons coals or MMBtu gas).

[b] All job-year estimates on this are full-time equivalent (FTE) jobs. Job estimates in the Demand-Side energy efficiency section (below) include both full-time and part-time jobs.

*Construction-related job-year changes are one-time impacts, occurring during each year of the 2 to 4 year period during which construction and HRI installation activities occur. Figures in table are average job-years during each of the years in each range. Negative job-year estimates when additional generating capacity must be built in the base case, but is avoided in the Guideline implementation scenarios due to HRI or Demand-side energy efficiency programs.

**Recurring Changes are job-years associated with annual recurring jobs including operating and maintenance activities and fuel extraction jobs. Newly built generating capacity creates a recurring stream of positive job-years, while retiring generating capacity, as well as avoided new built capacity, create a stream of negative job-years. In addition, there are recurring jobs prior to 2020 to fuel and operate new generating capacity brought online before 2020; the recurring jobs prior to 2020 are not estimated.

Table 6-5. Engineering-Based[a] Changes in Labor Utilization, State Compliance Approach (Number of Job-Years of Employment in Year)

Category	Option 1			Option 2		
Construction-related (One-time) Changes*						
	2017-2020	**2021-2025**	**2026-2030**	**2017-2020**	**2021-2025**	**2026-2030**
Heat Rate Improvement: Total	**32,200**	**0**	**0**	**30,800**	**0**	**n/a**
Boilermakers and General Construction	22,400	0	0	21,400	0	n/a
Engineering and Management	5,900	0	0	5,700	0	n/a
Equipment-related	2,900	0	0	2,800	0	n/a
Material-related	1,000	0	0	1,000	0	n/a
New Capacity Construction: Total	**28,200**	**-38,000**	**-36,100**	**23,000**	**-29,500**	n/a
Renewables	19,100	-8,900	-2,200	15,800	-6,300	n/a
Natural Gas	9,100	-29,100	-33,900	7,200	-23,200	n/a
Recurring Changes**						
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
Operation and Maintenance: Total	**-24,100**	**-25,300**	**-24,900**	**-16,800**	**-17,100**	n/a
Changes in Gas	2,500	-500	-3,200	1,500	-800	n/a
Retired Coal	-24,000	-22,500	-19,700	-16,400	-14,800	n/a
Retired Oil and Gas	**-2,600**	**-2,300**	**-2,000**	**-1,900**	**-1,500**	n/a
Fuel Extraction: Total	**-8,300**	**-14,600**	**-19,400**	**-6,500**	**-10,300**	n/a
Coal	-14,300	-17,800	-18,000	-11,500	-13,500	n/a
Natural Gas	6,000	3,200	-1,400	5,000	3,200	n/a
Supply-Side Employment Impacts – Quantified	**28,000**	**-77,900**	**-80,400**	**29,800**	**-56,900**	n/a

[a] Job-year estimates are derived from IPM investment and O&M cost estimates, as well as IPM fuel use estimates (tons coals or MMBtu gas)

[b] All job-year estimates on this are Full-Time Equivalent (FTE) jobs. Job estimates in the Demand-Side energy efficiency section (below) include both full-time and part-time jobs

*Construction-related job-year changes are one-time impacts, occurring during each year of the 2 to 4 year period during which construction and HRI installation activities occur. Figures in table are average job-years during each of the years in each range. Negative job-year estimates when additional generating capacity must be built in the base case, but is avoided in the Guideline implementation scenarios due to HRI or Demand-side energy efficiency programs.

**Recurring Changes are job-years associated with annual recurring jobs including operating and maintenance activities and fuel extraction jobs. Newly built generating capacity creates a recurring stream of positive job-years, while retiring generating capacity, as well as avoided new built capacity, create a stream of negative job-years. In addition, there are recurring jobs prior to 2020 to fuel and operate new generating capacity brought online before 2020; the recurring jobs prior to 2020 are not estimated.

6.6.2 Projected Changes in Employment in Demand-Side Energy Efficiency Activities

EPA anticipates that this rule may stimulate investment in clean energy technologies and services, resulting in considerable increases in energy efficiency in particular. We expect these increases in energy efficiency, specifically, to support a significant number of jobs existing in related industries.

In this section, we project employment impacts in demand-side energy efficiency activities arising from these guidelines using illustrative calculations. The approach uses information from power sector modeling and projected impacts on energy efficiency investments analyzed as part of Building Block 4 (see Chapter 3), and U.S. government data on employment and expenditures in energy efficiency. This approach is limited by the fact that we do not know which options states will choose for demand-side energy efficiency activities and by uncertainties associated with methods. These illustrative employment projections are gross; thus they do not include impacts of any shift in resources from other sectors. Nor does this analysis attempt to quantify employment impacts arising from changes in consumer expenditures away from energy towards other sectors. In other words, these projections are not attempts at estimating net national job creation. Also, this approach attempts to calculate the number of employees (full-time and part-time) rather than job-years as discussed in section 6.6.1. EPA requests public comment on all aspects of this proposed approach to partially quantifying demand-side management and energy efficiency employment impacts.

Investments in demand-side energy efficiency reduce energy required for a given activity by encouraging more efficient technologies (e.g., ENERGY STAR appliances), implementing energy improvements for existing systems (e.g., weatherization of older homes), or encouraging changes in behavior (e.g., reducing air conditioning during periods of high electricity demand).

Employment impacts of demand-side energy efficiency programs have not been extensively studied in the peer-reviewed, published economics literature. Instead, most research has focused on consumer response to and amount of energy savings achieved by these programs (e.g., Allcott (2011a, 2011b), Arimura et al. (2012)). Results suggest that demand-side energy efficiency programs reduce energy use and generate small increases in consumer welfare. These policy impacts are due to low investment in energy efficiency as described in “energy paradox” literature (Gillingham, Newell, and Palmer (2009), Gillingham and Palmer (2014)).[161]

Two recent articles discuss employment effects of demand-side energy efficiency

[161] For more information on this efficiency paradox see Chapter 3.

programs. Aldy (2013) describes clean energy investments funded by the American Recovery and Reinvestment Act of 2009, which "included more than $90 billion for strategic clean energy investments intended to promote job creation and the deployment of low-carbon technologies" (p. 137), with nearly $20 billion for energy efficiency investments. The Council of Economic Advisors (CEA) (2011) estimated higher economic activity and employment than would have otherwise occurred without the American Recovery and Reinvestment Act. Using CEA's methods to quantify job creation for the Recovery Act, Aldy uses the share of stimulus funds for clean energy investments to estimate job-years supported by the Recovery Act. The largest sources of job creation in clean energy are those that received the largest shares of stimulus funds: renewable energy, energy efficiency, and transit. Aldy's estimates, while informative, are not directly applicable for employment analysis in this rulemaking as there are important differences in expected employment impacts from a historically large fiscal stimulus specifically targeting job creation during a period of exceptionally high unemployment versus environmental regulations taking effect several years from now.

Yi (2013) analyzes clean energy policies and employment for U.S. metropolitan areas in 2006, prior to the Recovery Act, to evaluate impacts on clean energy job growth. Implementing an additional state clean energy policy tool (renewable energy policies, GHG emissions policies, and energy efficiency polices such as energy efficiency resource standards, appliance or equipment energy efficiency standards, tax incentives, and public building energy efficiency standards) is associated with 1% more clean energy employment within that MSA. These estimates are not transferable to this rulemaking since states are likely to change intensity as well as number of clean energy programs.

Lacking a peer-reviewed methodology, we propose the following approach to illustrate possible effects on labor demand in the energy efficiency sector due to demand-side management strategies. We use U.S. government data to divide the historical change in employment in the energy efficiency sector by the historical change in expenditure in the sector and multiply this fraction by projected expenditure in the sector undertaken in response to these proposed guidelines.

Data used for calculating the numerator of the fraction comes from the "energy efficiency" category of the 2010 and 2011 BLS *Green Goods and Services* surveys.[162] BLS does not report the denominator of the job per additional dollar fraction, however. Instead, the data include the fraction of green revenues received relative to total revenues in each North American Industrial Classification System (NAICS) code.[163] We multiply data on total revenues by NAICS by the fraction of green revenues reported by BLS to obtain green revenues. The only U.S. Government data source containing this revenue information for all NAICS sectors is the U.S. Economic Census. This Census is conducted at 5-year intervals (the latest available year is 2007), however, making it unsuitable for identifying the change in revenues from 2010 to 2011. Instead, we use data from the Annual Survey of Manufacturers. The disadvantage of this data source is that the manufacturing sector makes up only 50 percent of the 132 NAICS codes belonging to the energy efficiency sector as defined by the BLS *Green Goods and Services* surveys, with the remainder in the construction or service sectors. Thus, this analysis implicitly assumes that the same number of jobs per dollar are supported in construction and service sectors as in manufacturing. Using this approach we obtain a factor of 2.56 additional demand-side energy efficiency jobs per additional million 2011 dollars of expenditure.

Having calculated the fraction of additional jobs per additional dollar of energy efficiency expenditure, we use energy sector model projections of the first-year costs required for states to attain the goal of demand-side efficiency improvements set by building block four.[164] Multiplying this dollar expenditure by the jobs per additional dollar figure results in projected employment impacts for demand-side energy efficiency activities of 78,800 in 2020, 112,000 in 2025, and 111,800 in 2030 for both the proposed Option 1 regional and state compliance approaches. The estimates for Option 2 are shown on Table 6-6 below.

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[162]For more details on these surveys, see section 7.5.3.

[163] See detailed listing available here: http://www.bls.gov/ggs/naics_2012.xlsx.

[164] See Greenhouse Gas Abatement Measures TSD, Appendix 5-4.

Table 6-6. Estimated Demand-Side Energy Efficiency Employment Impacts For Option 1 and Option 2 for Both Regional and State Compliance Approaches

Source	Factor	Employment impact (jobs)*					
		Option 1			Option 2		
		2020	2025	2030	2020	2025	2030
BLS GGS additional jobs per additional million dollars	2.56	78,800	112,000	111,800	57,000	76,200	n/a

*Since these figures represent number of employees (full- or part-time) they should not be added to the full-time equivalent job-years reported in Table 6-5.

Although this approach has the advantage of illuminating the change in jobs for an incremental change in expenditures, this approach is limited by its focus on manufacturing sectors and direction of bias (overestimation or underestimation) cannot be determined at this time. The EPA is requesting comment on this method, data, identification of related studies and peer reviewed articles and other methods.

There is more uncertainty involved in this approach than the standard bottom-up engineering analysis used to estimate electricity generation and fuel production employment impacts of this rulemaking. For those, the EPA was able to identify a limited set of activities (e.g., constructing a new NGCC power plant), and study associated labor requirements. Demand-side energy efficiency improvements, in contrast, encompass a wide array of activities (subsidies for efficient appliances, “smart meters,” etc.). In addition, there is considerable uncertainty regarding which activities a state will choose. Thus, the validity of the jobs per dollar approach used here relies on the assumption that states will use a mix of activities similar to the 2011 composition of energy efficiency sectors identified by BLS.

In addition, the EPA does not have access to bottom-up information regarding labor requirements for these activities. Use of a constant job per dollar fraction is at best a crude approximation of these labor requirements. The EPA has identified several other limitations of this approach, outlined below.

Job Reclassification. Job numbers in this chapter represent gross changes in the affected sector. As such they may over-estimate impacts to the extent that jobs created displace workers employed elsewhere in the economy. For demand-side efficiency activities this potential over-statement is may be higher than in other sectors. If states encourage consumers to purchase ENERGY STAR appliances, for example, currently employed workers in factories and retail outlets may simply be given a different task. This approach, however, would count these workers as jobs created

Imports. The job per additional dollar fraction used in the employment projection is calculated based on jobs per dollar of revenue for domestic firms only. To the extent that spending on demand-side energy efficiency activities goes toward the purchase of imported goods this projection will overstate the U.S. employment impact of those expenditures.

Fixed Coefficient. Implicit in this approach is the assumption that employment impacts can be projected decades into the future on the basis of a single calculation from 2010-2011 data. The labor intensity of demand-side energy efficiency will likely change with technological innovation in the sector. In addition, even absent technological change, labor intensity of expenditures will likely change over time as states alter their portfolio of efficiency activities (e.g., by moving to higher cost activities after exhausting opportunities for low cost efficiency gains).

Non-additional Activities. Here we assume that all activities financed by demand-side energy efficiency expenditures are additional to what would have been undertaken in the absence of these programs. If utilities finance some actions customers would have undertaken in the absence of these programs (e.g., if a customer receives a rebate for an energy efficient appliance that would have been purchased without the rebate), these numbers would overestimate employment impacts of the proposed guidelines.

6.7 Conclusion

This chapter presents qualitative and quantitative discussions of potential employment impacts of the proposed guidelines for electricity generation, fuel production, and demand-side energy efficiency sectors. The qualitative discussion identifies challenges associated with estimating net employment effects and discusses anticipated impacts related to the rule. It includes an in-depth discussion of economic theory underlying analysis of employment impacts. Labor demand impacts for regulated firms can be decomposed into output and substitution effects, both of which may be positive or negative. Consequently, theory alone cannot predict the direction or magnitude of a regulation's employment impact. It is possible to combine theory with empirical study specific to the regulated firms and other relevant sectors if data and methods of sufficient detail and quality are available. Finally, economic theory suggests that labor supply effects are also possible.

We examine the peer-reviewed economics literature analyzing various aspects of labor demand, relying on the above theoretical framework. Determining the direction of employment effects in regulated industries is challenging because of the complexity of the output and substitution effects. Complying with a new or more stringent regulation may require additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms (and firms in other relevant industries) in their production processes. The available literature illustrates some of the difficulties for empirical estimation: studies sometimes rely on confidential plant-level employment data from the U.S. Census Bureau, possibly combined with pollution abatement expenditure data that are too dated to be reliably informative. In addition, the methods do not permit estimation of net economy-wide effects. Empirical analysis at the industry level requires estimates of product demand elasticity; production factor substitutability; supply elasticity of production factors; and the share of total costs contributed by wages, by industry, and perhaps even by facility. For environmental rules, many of these data items are not publicly available, would require significant time and resources in order to access confidential U.S. Census data for research, and also would not be necessary for other components of a typical RIA. Econometric studies of environmental rules converge on the finding that employment effects, whether positive or negative, have been small in regulated sectors.

The illustrative quantitative analysis in this chapter projects a subset of potential employment impacts in the electricity generation, fuel production, and demand-side energy efficiency sectors. States have the responsibility and flexibility to implement policies and practices for compliance with Proposed EGU GHG Existing Source Guidelines. As such, given the wide range of approaches that may be used, quantifying the associated employment impacts is difficult. EPA’s employment analysis includes projected employment impacts associated with these guidelines for the electric power industry, coal and natural gas production, and demand-side energy efficiency activities. These projections are derived, in part, from a detailed model of the electricity production sector used for this regulatory analysis, and U.S. government data on employment and labor productivity. In the electricity, coal, and natural gas sectors, the EPA estimates that these guidelines could have an employment impact of roughly 25,900 job-years in 2020 for Option 1 and 26,700 for Option 2 of that same year (see Tables 6-4 and 6-5). Employment impacts from demand-side energy efficiency activities are based on historic data on jobs supported per dollar of expenditure. Demand-side energy efficiency employment impacts would approximately be 78,800 jobs in 2020 for both Option 1 regional and state compliance approaches (see Table 6-6). The IPM-generated job-year numbers for the electricity, coal and natural gas sectors should not be added to the demand-side efficiency job impacts since the former are reported in full-time equivalent jobs, whereas the latter do not distinguish between full- and part-time employment. Finally, note again that this is an illustrative analysis, and CAA section 111(d) allows each state to determine the appropriate combination of, and the extent of its reliance on, measures for its state plan, by way of meeting its state-specific goal. Given the flexibilities afforded states in complying with the emission guidelines, the impacts reported in this chapter are illustrative of compliance actions states may take.

6.8 References

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APPENDIX 6A: ESTIMATING SUPPLY-SIDE EMPLOYMENT IMPACTS OF THE PROPOSED EGU GHG EXISTING SOURCE GUIDELINES

This appendix presents the methods used to estimate the supply-side employment impacts of the Proposed Electric Generating Unit Greenhouse Gas (EGU GHG) Existing Source Guidelines. The focus of the employment analysis is limited to the direct changes in the amount of labor needed in the power, fuels and generating equipment sectors directly influenced by compliance with the Guidelines. It does not include the ripple effects of these impacts on the broader economy (i.e., the "multiplier" effect), nor does it include the wider economy-wide effects of the changes to the energy markets, such as changes in electricity prices.

The methods used to estimate the supply-side employments are based on methods previously developed for the Mercury and Air Toxics Standards (MATS) Regulatory Impact Analysis (RIA). The methods used in this analysis to estimate the recurring labor impacts (e.g., labor associated with operating and maintaining generating units, as well as labor needed to mine coal and natural gas) are the same as was used in MATS (with updated data where available).

The labor analysis in the MATS RIA was primarily concerned with the labor needs of retrofitting pollution control equipment. The EGU GHG Existing Source Guidelines labor analysis, however, involves the quantity and timing of the labor needs of building new renewable and natural gas, as well as making heat rate improvements (HRI) at existing coal fired EGUs. These construction-related compliance activities in the EGU GHG Existing Source Guidelines required developing additional appropriate analytical methods that were not needed for the MATS analysis. The newly developed analytical methods for the construction-related activities are similar in structure and overall approach to the methods used in MATS, but required additional data and engineering information not needed in the MATS RIA.

6A.1 General Approach

The analytical approach used in this analysis is a bottom-up engineering method combining the EPA's cost analysis of the proposed guidelines with data on labor productivity, engineering estimates of the amount and types of labor needed to manufacture, construct, and operate different types of generating units, and prevailing wage rates for skilled and general labor categories. The approach involved using power sector projections and various energy market implications under the proposed EGU GHG Existing Source Guidelines from modeling conducted with the EPA Base Case version 5.13, using the Integrated Planning Model (IPM®)[165], along with data from secondary sources, to estimate the first order employment impacts for 2020, 2025, and 2030.

Throughout the supply-side labor analysis the engineering approach projects labor changes measured as the change in each analysis year in job-years[166] employed in the power generation and directly related sectors (e.g., equipment manufacturing, fuel supply and generating efficiency services). Job-years are not individual jobs, nor are they necessarily permanent nor full time jobs. Job-years the amount of work performed by one full time equivalent (FTE) employee in one year. For example, 20 job-years in 2020 may represent 20 full-time jobs or 40 half-time jobs in that year, or any combination of full- and part-time workers such that total 20 FTEs.

6A.1.1 Employment Effects Included In the Analysis

The estimates of the employment impacts (both positive and negative) are divided into five categories:

- additional employment to make HRI[167] at existing coal fired EGUs;
- additional construction-related employment to manufacture and install additional new generating capacity (renewables, and natural gas combined cycle or combustion turbine units) when needed as part of early compliance actions;

[165] Results for this analysis were developed using various outputs from EPA's Base Case v.5.13 using ICF's Integrated Planning Model (IPM®). This case includes all of the underlying modeling that was developed by EPA with technical support from ICF International, Inc. See http://www.epa.gov/powersectormodeling/BaseCasev513.html for more information.

[166] Job-years are not individual jobs, but rather the amount of work performed by the equivalent of one full-time individual for one year. For example, 20 job-years in 2020 may represent 20 full-time jobs or 40 half-time jobs in that year.

[167] Heat rate improvements could include a range of activities in the power plant to lower the heat rate required to generate a net electrical output. Assuming all other things being equal, a lower heat rate is more efficient because less fuel is needed per unit of electric output.

- lost construction-related employment opportunities due to reductions in the total amount of new generating capacity needed to be built in the later years because of reduced overall demand for electricity because of demand-side energy efficiency activities;
- lost operating and maintenance employment opportunities due to increased retirements of coal and small oil/gas units;
- changes (both positive and negative) in coal mining and natural gas extraction employment due to the aggregate net changes in fuel demands arising from all the activities occurring due to compliance with the proposed guidelines.

Some of the changes are one-time labor effects which are associated with the building (or avoiding building) new generating capacity and installing HRI. This type of employment effects involves project-specific labor that is used for 2 to 4 years to complete a specific construction and installation type of project. There are other labor effects, however, which continue year after year. For example, bringing new generating capacity online creates an ongoing need for labor to operate and maintain the new generating capacity throughout the expected service life of the unit. New generating capacity also creates a need for additional employment to provide the fuel annually to run the new capacity. There are also continuing effects from the lost operations and maintenance (O&M) and fuel sector labor opportunities from decisions to retire existing capacity, as well as similar lost labor opportunities from decisions to reduce a portion of the amount of additional capacity needed in the base case.

6A.2 Employment Changes due to Heat Rate Improvements

The employment changes due to HRI were estimated based on the incremental MW capacity estimated to implement such improvements by 2020 as indicated by the analysis conducted by EPA. The heat rate improvement job impacts were assumed to have all occurred by 2020 and thus this study assumes there will be no HRI related jobs after 2020 (i.e., no permanent O&M related jobs due to HRI for 2025 or 2030). EPA modeled the heat rate improvements exogenously in IPM using the assumption that all “relevant” units can improve their heat rate by 6 percent at a capital cost of $100/kW. This study assumes that these investments will occur over a four-year period culminating in 2020. Hence, the per-year cost of heat rate was calculated to be $25/kW, and this cost was used in the next step.

This cost was then allocated to four categories based on the estimates provided by Andover Technology Partners (ATP), which were adapted from proxy projects involving installation of combustion control retrofits, such as those installed under the Best Available Retrofit Technology (BART) submissions from coal-fired power plants located in Wyoming and Arizona. For more details, refer to the Staudt (2014) report.[168] These proxies were chosen to ensure that the types of activities involved and their associated costs would be representative of those investments EPA expects power plants to undertake for efficiency upgrades.

Information on cost for these proxies were then extrapolated to approximate the labor requirements for four broad categories of labor – boilermakers and general construction, engineering and management support labor, labor required to produce the equipment in upstream sectors, and labor required to supply the materials (assumed to be primarily steel) in upstream sectors. More details about these estimates are provided in the Staudt (2014) report.

Based on the cost allocated in each categories and output per worker figures for respective industries in 2020, the employment gains for heat rate improvement were estimated[169] for 2020 using the assumptions summarized in Table 6A-1 below. Output per workers in future years were adjusted to account for growth in labor productivity, based on historical evidence of productivity growth rates for the relevant sectors.

Table 6A-1. Labor Productivity Growth Rate due to Heat Rate Improvement

	Share of the Total Capital Cost	Output/Worker (2020)	Labor Productivity Growth Rate
Boilermaker and Gen. Const.	40%	$78,500	0%
Management/Engineering	20%	$141,000	1.3%
Equipment	30%	$458,000	3.2%
Materials	10%	$424,000	-1.2%

[168] Staudt, James, Andover Technology Partners, Inc. Estimating Labor Effects of Heat Rate Improvements. Report prepared for the proposed EGU GHG Existing Source Guidelines, March 6, 2014.

[169] Total value of shipments or receipts in 2007 and total employees were taken from 2007 Economic Census, Statistics by Industry for Mining and Manufacturing sectors. The average annual growth rate of labor productivity was taken from the Bureau of Labor Statistics. Average growth rate calculated for years 1992-2007, applied to 2007 productivity to determine 2020 estimates of productivity. For the construction sector, BLS productivity growth rate data was unavailable. Because of this, and lack of reliable data on construction sector productivity growth, the output per worker for the construction sector was not forecasted to 2020, and the most recent available value from 2007 was used.

For these output per worker figures, a power sector construction industry (NAICS 237130) was used for general construction and boilermakers, Engineering Services (NAICS 54133) was used for the engineering and management component, Machinery Manufacturing (NAICS 333) was used for the equipment sector, and steel manufacturing (NAICS 33121) was used for materials. Use of machinery manufacturing for equipment and steel for materials was based on an analysis of the types of materials and equipment needed for these projects, and what EPA determined to be the most appropriate industry sectors for those. For more details, refer to the Staudt (2014) report.

6A.2.1 Employment Changes Due to Building (or Avoiding) New Generation Capacity

Employment changes due to new generation units were based on the incremental changes in capacity (MW), capital costs ($MM), and fixed operations and maintenance (FOM) costs ($MM) between the policy scenario and the base case in a given year.

New capacities were aggregated by generation type into the following categories:

- Combined Cycle,
- Combustion Turbine, and
- Renewables (which includes biomass, geothermal, landfill gas, onshore wind, and solar).

For each category, the analysis estimated the impacts due to both the construction and operating labor requirements for corresponding capacity changes. The construction labor was estimated using information on the capital costs, while the operating labor was estimated using the FOM costs.

Because IPM outputs provide annualized capital costs ($MM), EPA first converted the annualized capital costs to changes in the total capital investment using the corresponding capital charge rates.[170] These total capital investments were then converted to annual capital investments using assumptions about the estimated duration of the construction phase, in order to estimate the

[170] Capital charge rates obtained from EPA's resource, EPA #450R13002: Documentation for EPA Base Case v.5.13 using the Integrated Programming Model (IPM).

annual impacts on construction phase labor. Duration estimates were based on assumptions for construction lengths used in EPA's IPM modeling.[171] Specific assumptions used for different generating technologies are shown in Table 6A-2 below.

Table 6A-2. Capital Charge Rate and Duration Assumptions

New Investment Technology	Capital Charge Rate	Duration (Years)
Advanced Combined Cycle	10.3%	3
Advanced Combustion Turbine	10.6%	2
Renewables		
Biomass	9.5%	3
Wind (Onshore)	10.9%	3
Landfill Gas	10.9%	3
Solar	10.9%	3
Geothermal	10.9%	3

Annual capital costs for each generation type were then broken down into four categories: equipment, material (which is assumed to be primarily steel), installation labor, and support labor in engineering and management. The percentage breakdowns shown in Table 6A-3 were estimated using information provided by Staudt (2014), based primarily on published budgets for new unit assembled in a study for the National Energy Technology Laboratory (NETL). For more details, refer to the Staudt (2014) report. Annual capital costs for each generation type provided by the IPM output were allocated according to this breakdown.

Table 6A-3. Expenditure Breakdown due to New Generating Capacity

	Equipment	Material	Labor	Eng. and Const. Mgt
Renewables	54%	6%	31%	9%
Combined Cycle	65%	10%	18%	7%
Combustion Turbine	65%	10%	18%	7%

The short-term construction labor of the new generation units were based on output ($ per worker) figures for the respective sectors. The total direct workers per $1 million of output for the baseline year 2007 were forecasted to the years under analysis using the relevant labor productivity growth rate. Table 6A-4 shows the figures for each of the five productivities: general power plant construction; engineering and management; material use; equipment use;

[171] Ibid.

and plant operators. The resulting values were multiplied by the capital costs to get the job impact.

Table 6A-4. Labor Productivity due to New Generating Capacity

	Labor Productivity Growth Rate	Workers per Million $ (2007)
General Power Plant Construction	0.0%	5.7
Engineering and Management	1.3%	5.2
Material Use (Steel)	-1.2%	2.0
Equipment Use (Machinery)	3.2%	3.3
Plant Operators	2.8%	10.8

General installation labor, assumed to be mostly related to the general power plant construction phase, was matched with the power industry specific construction sector. Engineering/management was matched to the engineering services sector to determine their respective output per worker. For materials, EPA assumed steel to be the proxy and used the steel manufacturing sector for this productivity. Equipment was assumed to primarily come from machinery manufacturing sector (such as turbines, engines and fans).

The net labor impact for construction labor for a given year was adjusted to account for changes in capacity that has already taken place in the prior IPM run year. Because IPM reports cumulative changes for new generating capacity for any given run year, this adjustment ensured that the short-term construction phase job impacts in any given run year does not reflect the cumulative effects of prior construction changes for the given policy scenario. The estimated amount of the change in construction-related labor in a single IPM run year (e.g., 2025) represents the average labor impact that occurs in all years between that IPM run year and the previous run year (i.e., the labor estimates derived from the 2025 IPM run year are the average annual labor impacts in 2021 through 2025). The construction labor results for 2020 represent the average labor impacts in 2017 through 2020.

The plant operating employment estimates used a simpler methodology as the one described above. The operating employment estimates use the IPM estimated change in FOM costs for the IPM run year. Because the FOM costs are inherently estimates for a single year, the operating employment estimates are for a single year only. While there are obviously operating employment effects occurring in every year throughout the entire IPM estimation period (2017-2030), the labor analysis only estimates the single year labor impacts in the IPM run years: 2020, 2025 and 2030. The total direct workers for $1 million and labor productivity growth rate provided for plant operators in Table 6A-4 were used to estimate the employment impact.

6A.2.2 Employment Changes due to Coal and Oil/Gas Retirements

Employment changes due to plant retirements were calculated using the IPM projected changes in retirement capacities for coal and oil/gas units for the relevant year and the estimated changes in total FOM costs due to those retiring units. Thus, the basic assumption in this analysis was that increased retirements (over the base case) will lead to reduced FOM expenditures at those plants which were assumed to lead to direct job losses for plant workers.

In order to estimate the total FOM changes due to retirements, EPA first estimated the average FOM costs ($/kW) for existing coal-fired and oil/gas-fired units in the base case, as shown in Table 6A-5 below. It was assumed that the average FOM cost of existing units in the base case can be used as a proxy for the lost economic output due to fossil retirements. Thus, changes in the FOM costs for these retiring units were derived by taking the product of the incremental change in capacity and the average FOM costs. These values were converted to lost employment using data from the Economic Census and BLS on the output/worker estimates for the utility sector.[172]

Table 6A-5. Average FOM Cost Assumptions

	2020	2025	2030
Coal	65	68	69
Oil and Gas	21	22	22

Note that the retirement related employment losses are assumed to include losses directly affecting the utility sector, and do not include losses in upstream sectors that supply other inputs to the EGU sector (except fuel related job losses, which are estimated separately and discussed in the next section).

6A.2.3 Employment Changes due to Coal and Oil/Gas Retirements

Two types of employment impacts due to projected fuel use changes were estimated in

[172] The same specific sources as cited before, however, used workers and total payroll.

this section. First, employment losses due to either reductions or shifts in coal demand were estimated using an approach similar to EPA's coal employment analyses under Title IV of the Clean Air Act Amendments. Using this approach, changes in coal demand (in short tons) for various coal supplying regions were taken from EPA's base and policy case runs for the proposed EGU GHG NSPS. These changes were converted to job-years using U.S. Energy information Administration (EIA) data on regional coal mining productivity (in short tons per employee hour), using 2008 labor productivity estimates.[173,174]

Specifically, the incremental changes to coal demand were calculated based on the coal supply regions in IPM -- Appalachia, Interior, and West and Waste Coal (which was estimated using U.S. total productivity). Worker productivity values used for estimating coal related job impacts are shown in Table 6A-6 below.

Table 6A-6. Labor Productivity due to New Generating Capacity

	Labor Productivity
Coal (Short tons/ employee hour)	
Appalachia	2.91
Interior	4.81
West	19.91
Waste	5.96
Natural Gas (MMBtu/ employee hour)	126
Pipeline Construction (Workers per $Million)	5.1

For natural gas demand, labor productivity per unit of natural gas was unavailable, unlike coal labor productivities used above. Most secondary data sources (such as Census and EIA) provide estimates for the combined oil and gas extraction sector. This section thus used an adjusted labor productivity estimate for the combined oil and gas sector that accounts for the relative contributions of oil and natural gas in the total sector output (in terms of the value of energy output in MMBtu). This estimate of labor productivity was then used with the

[173] From EIA Annual Energy Review, Coal Mining Productivity Data. Used 2008.

[174] Unlike the labor productivity estimates for various equipment resources which were forecasted to 2020 using BLS average growth rates, this study uses the most recent historical productivity estimates for fuel sectors. In general, labor productivity for the fuel sectors (both coal and natural gas) showed a significantly higher degree of variability in recent years than the manufacturing sectors, which would have introduced a high degree of uncertainty in forecasting productivity growth rates for future years.

incremental natural gas demand for the respective IPM runs to estimate the job-years for the specific year (converting the TCF of gas used projected by IPM into MMBtu using the appropriate conversion factors). In addition, the pipeline construction costs were estimated using endogenously determined gas market model parameters in IPM used by EPA for the MATS rule (using assumptions for EPA's Base Case v4.10). This analysis assumed that the need for additional pipeline would be proportionate to those projected for the MATS rule and were hence extrapolated from those estimates.[175] The job-years associated with the pipeline construction were included in the natural gas employment estimates.

[175] See "Employment Estimates of Direct Labor in Response to the Proposed Toxics Rule in 2015". Technical Support Document, March 2011.

CHAPTER 7: STATUTORY AND EXECUTIVE ORDER ANALYSIS

7.1 Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review

Under section 3(f) (1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more or to adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. The $100 million threshold can be triggered by either costs or benefits, or a combination of them. Accordingly, the EPA submitted this action to OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action. The EPA also prepared an analysis of the potential costs and benefits associated with this action in this Regulatory Impact Analysis (RIA).

Consistent with EO 12866 and EO 13563, the EPA estimated the costs and benefits for illustrative compliance approaches of implementing the proposed guidelines. This proposal sets goals to reduce CO_2 emissions from the electric power industry. Actions taken to comply with the proposed guidelines will also reduce the emissions of directly emitted $PM_{2.5}$, sulfur dioxide (SO_2) and nitrogen oxides (NO_X). The benefits associated with these PM, SO_2 and NO_X reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA has used the U.S. government's social cost of carbon (USG SCC) estimates (i.e., the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year), to analyze CO_2 climate impacts of this rulemaking. The four USG SCC estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this summary, EPA provides the estimate of climate benefits associated with the SCC value deemed to be central by the USG (the model average at 3% discount rate). The EPA estimates that in 2020, the Option 1 regional compliance approach will yield monetized climate benefits of approximately $17 billion with a 3 percent model average (2011$). The air pollution health co-benefits in 2020 are estimated to be $16 billion to $37 billion for a 3 percent discount rate, and $15 billion to $34 billion (2011$) for a 7 percent discount rate. The annual illustrative compliance costs estimated by IPM, inclusive of demand side energy efficiency program and participant costs and MRR costs, are approximately $5.5 billion (2011$) in 2020. The quantified net benefits (the difference between monetized benefits and costs) in 2020, are estimated to be $28 billion to $49 billion using a 3 percent discount rate (model average) and $26 to $45 billion using a 7 percent discount rate (model average, 2011$). For Option 1 state compliance approach, the climate benefits are estimated to be $18 billion (2011$). The air pollution health co-benefits in 2020 for the Option 1 state compliance approach are estimated to be $17 billion to $40 billion for a 3 percent discount rate, and $15 billion to $36 billion (2011$) for a 7 percent discount rate. The annual illustrative compliance costs estimated by IPM, inclusive of demand side energy efficiency program and participant costs and MRR costs, are approximately $7.5 billion (2011$) in 2020. The quantified net benefits in 2020, are estimated to be $27 billion to $50 billion using a 3 percent discount rate (model average) and $26 to $46 billion using a 7 percent discount rate (model average, 2011$).

For Option 1 regional compliance approach in 2030, the EPA estimates this proposal will yield monetized climate benefits of approximately $30 billion (3 percent, model average, 2011$). The air pollution health co-benefits in 2030 are estimated to be $25 billion to $59 billion for a 3 percent discount rate, and $23 billion to $54 billion (2011$) for a 7 percent discount rate. The annual illustrative compliance costs estimated using IPM, inclusive of demand side energy efficiency program and participant costs and MRR costs, are approximately $7.3 billion (2011$) in 2030. The quantified net benefits (the difference between monetized benefits and costs) in 2030, are estimated to be $48 billion to $82 billion using a 3 percent discount rate and $46 to $77 billion assuming a 7% discount rate (model average, 2011$). For the Option 1 state compliance approach, net benefits in 2030 are estimated to be $49 to $84 billion (3 percent discount rate) and $46 to 79 billion (7 percent discount rate (2011$). Compliance costs are estimated to be $8.8 billion (2011$). Based upon the foregoing discussion, it remains clear that the benefits of this proposal are substantial, and far exceed the costs. Additional benefit, cost and net benefit estimates for Option 1 and Option 2 are provided in Chapter 8 of this report.

7.2 Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq*. The Information Collection Request (ICR) document prepared by the EPA has been assigned the EPA ICR number 2503.01.

The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a state plan to limit CO_2 emissions from existing sources in the power sector. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). 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.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation of this proposed action) is estimated to be a range of 316,217 hours at a total annual labor cost of $22,381,044, to 633,001 hours at a total annual labor cost of $44,802,243. The lower bound estimate reflects the assumption that some states already have energy efficiency and renewable energy programs in place. The higher bound estimate reflects the assumption that no states have energy efficiency and renewable energy programs in place. The total annual burden for the federal government (averaged over the first 3 years following promulgation of this proposed action) is estimated to be 53,300 hours at a total annual labor cost of $2,958,005. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations are listed in 40 CFR part 9 and 48 CFR Chapter 15.

7.3 Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule, subject to notice and comment rulemaking requirements, under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as:

1. A small business that is defined by the SBA's regulations at 13 CFR 121.201 (for the electric power generation industry, the small business size standard is an ultimate parent entity with less than 750 employees). The NAICS codes for the affected industry are in Table 7-1 below.
2. A small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000.
   A small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Table 7-1. Potentially Regulated Categories and Entities[a]

Category	NAICS Code	Examples of Potentially Regulated Entities
Industry	221112	Fossil fuel electric power generating units.
State/Local Government	221112[b]	Fossil fuel electric power generating units owned by municipalities.

[a] Include NAICS categories for source categories that own and operate electric power generating units (includes boilers and stationary combined cycle combustion turbines).

[b] State or local government-owned and operated establishments are classified according to the activity in which they are engaged.

After considering the economic impacts of this proposed rule on small entities, EPA certifies that this action will not have a significant economic impact on a substantial number of small entities.

The proposed rule will not impose any requirements on small entities. Specifically, emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states establish standards on existing sources and it is those state requirements that could potentially impact small entities. Our analysis here is consistent with the analysis of the analogous situation arising when the EPA establishes NAAQS, which do not impose any requirements on regulated entities. As here, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their state implementation plans. See American Trucking Assoc. v. EPA, 175 F.3d 1029, 1043-45 (D.C. Cir. 1999) national standards for allowable concentrations of particulate matter in ambient air as required by section 109 of the CAA. *See also American Trucking Associations* v. *EPA.* 175 F.3d at 1044–45 (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

Nevertheless, the EPA is aware that there is substantial interest in the proposed rule among small entities (municipal and rural electric cooperatives). As detailed in section III.A.of the preamble, the EPA has conducted an unprecedented amount of stakeholder outreach on setting emission guidelines for existing EGUs. While formulating the provisions of the proposed rule, the EPA considered the input provided over the course of the stakeholder outreach. Section III.B. of the preamble describes the key messages from stakeholders. In addition, as described in the RFA section of the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1499-1500, January 8, 2014), the EPA conducted outreach to representatives of small entities while formulating the provisions of the proposed standards. Although only new EGUs would be affected by those proposed standards, the outreach regarded planned actions for new and existing sources. We invite comments on all aspects of the proposal and its impacts, including potential impacts on small entities.

7.4 Unfunded Mandates Reform Act (UMRA)

This proposed action does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Specifically, the emission guidelines proposed under CAA section 111(d) do not impose any direct compliance requirements on regulated entities, apart from the requirement for states to develop state plans. The burden for states to develop state plans in the 3 year period following promulgation of the rule was estimated and is listed in section IX B. of the preamble for the rulemaking, but this burden is estimated to be below $100 million in any one year. Thus, this proposed rule is not subject to the requirements of section 202 or section 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

In light of the interest among governmental entities, the EPA initiated consultations with governmental entities while formulating the provisions of the proposed standards for new EGUs. Although only new EGUs would be affected by those proposed standards, the outreach regarded planned actions for new and existing sources. As described in the UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1500-1501, January 8, 2014), the EPA consulted with the following 10 national organizations representing state and local elected officials:

- National Governors Association
- National Conference of State Legislatures
- Council of State Governments
- National League of Cities
- U.S. Conference of Mayors
- National Association of Counties
- International City/County Management Association
- National Association of Towns and Townships
- County Executives of America

- Environmental Council of States

On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs.

While formulating the provisions of these proposed emission guidelines, the EPA also considered the input provided over the course of the extensive stakeholder outreach conducted by the EPA.

7.5 Executive Order 13132, Federalism

Under Executive Order 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or the EPA consults with state and local officials early in the process of developing the proposed action.

The EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. As discussed in the Supporting Statement found in the docket for this rulemaking, the development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the proposed rule, as well as time to work with state legislatures as appropriate, and develop a plan submittal.

The EPA consulted with state and local officials early in the process of developing the proposed action to permit them to have meaningful and timely input into its development. As described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1501, January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. This outreach regarded planned actions for new, reconstructed, modified and existing sources. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting on April 12, 2011, in Washington DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments,

(4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs. In addition, extensive stakeholder outreach conducted by the EPA allowed state leaders, including governors, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with EPA officials and provide input regarding reducing carbon pollution from power plants.

A detailed Federalism Summary Impact Statement (FSIS) describing the most pressing issues raised in pre-proposal and post-proposal comments will be forthcoming with the final rule, as required by section 6(b) of Executive Order 13132. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed action from State and local officials.

7.6 Executive Order 13045, Protection of Children from Environmental Health Risks and Safety

The EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5-501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the CO_2 emission reductions resulting from implementation of the proposed guidelines, as well as substantial ozone and $PM_{2.5}$ emission reductions as a co-benefit, would further improve children's health.

7.7 Executive Order 13211, Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355; May 22, 2001) requires the EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and

Regulatory Affairs, OMB, for actions identified as ‘‘significant energy actions.’’ This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. We have prepared a Statement of Energy Effects for this action as follows. We estimate a 4 to 7 percent increase in retail electricity prices, on average, across the contiguous U.S. in 2020, and a 16 to 22 percent reduction in coal-fired electricity generation as a result of this rule. The EPA projects that electric power sector delivered natural gas prices will increase by about 8 to 12 percent in 2020 and reflect no change to a decrease of approximately 3 percent in 2030. Additional information is available in Chapter 3 of this RIA.

7.8 National Technology Transfer and Advancement Act (NTTAA)

Section 12(d) of the NTTAA of 1995 (Public Law No. 104-113; 15 U.S.C. 272 note) directs the EPA to use Voluntary Census Standards (VCS) in its regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs the EPA to provide Congress, through annual reports to the OMB, with explanations when an agency does not use available and applicable VCS. This proposed rulemaking does not involve technical standards.

The EPA welcomes comments on this aspect of the proposed rulemaking and specifically invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this action.

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

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its 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.

Section II.A of the preamble summarizes the public health and welfare impacts from GHG emissions that were detailed in the 2009 Endangerment Finding under CAA section 202(a)(1).[176] As part of the Endangerment Finding, the Administrator considered climate change risks to minority or low-income populations, finding that certain parts of the population may be especially vulnerable based on their circumstances. These include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

Strong scientific evidence that the potential impacts of climate change raise environmental justice issues is found in the major assessment reports by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies, summarized in the record for the Endangerment Finding. Their conclusions include that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those on established reservations that are restricted to reservation boundaries and therefore have limited relocation options. Tribal 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. Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are likely to experience disruptive impacts, including shifts in the range or abundance of wild species crucial to their livelihoods and well-being. The most recent assessments continue to strengthen scientific understanding of climate change risks to minority and low-income populations.

This proposed rule would limit GHG emissions by establishing CO_2 emission guidelines

[176] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 Fed. Reg. 66,496 (Dec. 15, 2009) ("Endangerment Finding").

for existing fossil fuel-fired EGUs. In addition to reducing CO_2 emissions, implementing the proposed rule would reduce other emissions from EGUs that become dispatched less frequently due to their relatively low energy efficiency. These emission reductions will include SO_2 and NOx, which form ambient $PM_{2.5}$ and ozone in the atmosphere, and hazardous air pollutants (HAP), such as mercury and hydrochloric acid. In the final rule revising the annual $PM_{2.5}$ NAAQS[177], the EPA identified persons with lower socioeconomic status as an at-risk population for experiencing adverse health effects related to PM exposures. Persons with lower socioeconomic status have been generally found to have a higher prevalence of pre-existing diseases, limited access to medical treatment, and increased nutritional deficiencies, which can increase this population's risk to PM-related and ozone-related effects.[178] Therefore, in areas where this rulemaking reduces exposure to $PM_{2.5}$, ozone, and methylmercury persons with low socioeconomic status would also benefit. The regulatory impact analysis (RIA) for this rulemaking, included in the docket for this rulemaking, provides additional information regarding the health and ecosystem effects associated with these emission reductions.

While there will be many locations with improved air quality for $PM_{2.5}$, ozone, and HAP, there may also be EGUs whose emissions of one or more of these pollutants or their precursors increase as a result of the proposed emission guidelines for existing fossil fuel-fired EGUs. This may occur at EGUs that become dispatched more intensively than in the past because they become more energy efficient. The EPA has considered the potential for such increases and the environmental justice implications of such increases.

As we noted in the NSR discussion in this preamble, as part of a state's CAA section 111(d) plan, the state may require an affected EGU to undertake a physical or operational changes to improve the unit's efficiency that result in an increase in the unit's dispatch and an increase in the unit's annual emissions of GHGs and/or other regulated pollutants. A state can take steps to avoid increased utilization of particular EGUs and thus to avoid any significant

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[177] U.S. EPA (2013). National Ambient Air Quality Standards for Particulate Matter, Final Rule. *Federal Register* 78 (15 January 2013): 3086-3287.

[178] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Integrated Science Assessment for Particulate Matter (Final Report)*. EPA-600-R-08-139F. National Center for Environmental Assessment – RTP Division. December. Available on the Internet at <http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546>.

increases in emissions including emissions of other regulated pollutants whose environmental effects would be more localized around the affected EGU. To the extent that states take this path, there would be no new environmental justice concerns in the areas near such EGUs. For any EGUs that make modifications that do trigger NSR permitting, the applicable local, state, or federal permitting program will ensure that there are no new NAAQS violations and that no existing NAAQS violations are made worse. For those EGUs in a permitting situation for which the EPA is the permit reviewing authority, the EPA will consider environmental justice issues as required by Executive Order 12898.

In addition to some EGUs possibly being required by a state to make modifications for increased energy efficiency, another effect of the proposed CO_2 emission guidelines for existing fossil fuel-fired EGUs would be increased utilization of other, unmodified EGUs with relatively low GHG emissions per unit of electrical output, in particular high efficiency gas-fired EGUs. Because such EGUs would not have been modified physically nor changed their method of operation, they would not be subject to review in the NSR permitting program. Such plants would have more hours in the year in which they operate and emit pollutants, including pollutants whose environmental effects if any would be localized rather than global as is the case with GHG emissions. Changes in utilization already occur now as demands for and sources of electrical energy evolve, but the proposed CO_2 emission guidelines for existing fossil fuel-fired EGUs can be expected to cause more such changes. Because gas-fired EGUs emit essentially no mercury, increased utilization would not increase methylmercury concentrations in their vicinities. Increased utilization generally would not cause higher peak concentrations of $PM_{2.5,}$ NOx, or ozone around such EGUs than is already occurring because peak hourly or daily emissions generally would not change, but increased utilization may make periods of relatively high concentrations more frequent. It should be noted that the gas-fired sources that are likely to become dispatched more frequently than at present have very low emissions of primary particulate matter, SO_2 and HAP per unit of electrical output, such that local (or regional) air quality for these pollutants is likely to be affected very little. For natural gas-fired EGUS, the EPA found that regulation of HAP emissions "is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility RTC" 65 FR 79831. In studies done by DOE/NETL comparing cost and performance of coal- and NG-fired generation, they assumed SO_2, PM (and Hg) emissions to be "negligible." Their studies predict NOx emissions from a NGCC unit to be approximately 10 times lower than a subcritical or supercritical coal-fired boiler. Many are also very well controlled for emission of NOx through the application of after combustion controls such as selective catalytic reduction, although not all gas-fired sources are so equipped. Depending on the specificity of the state CAA section 111(d) plan, the state may be able to predict which EGUs and communities may be in this type of situation and to address any concerns about localized NO_2 concentrations in the design of the CAA section 111(d) program, or separately from the CAA section 111(d) program but before its implementation. In any case, existing tracking systems will allow states and the EPA to be aware of the EGUs whose utilization has increased most significantly, and thus to be able to prioritize our efforts to assess whether air quality has changed in the communities in the vicinity of such EGUs. There are multiple mechanisms in the CAA to address situations in which air quality has degraded significantly. In conclusion, this proposed rule would result in regional and national pollutant reductions; however, there likely would also be some locations with more times during the year of relatively higher concentrations of pollutants with potential for effects on localized communities than would be experienced in the absence of the proposed rule. The EPA cannot exactly predict how emissions from specific EGUs would change as an outcome of the proposed rule due to the state-led implementation. Therefore, the EPA has concluded that it is not practicable to determine whether there would be disproportionately high and adverse human health or environmental effects on minority, low income, or indigenous populations from this proposed rule.

In order to provide opportunities for meaningful involvement early on in the rule making process, the EPA has hosted webinars and conference calls on August 27, 2013 and September 9, 2013 on the proposed rule specifically for environmental justice communities and has taken all comments and suggestions into consideration in the design of the emission guidelines.

7.10 Executive Order 13175 - Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It would not impose substantial direct compliance costs on tribal governments that have affected EGUs located in their area of Indian country. Tribes are not required to, but may, develop or adopt CAA programs. Tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs. To the extent that a tribal government seeks and attains treatment in a manner similar to a state (TAS) status for that purpose and is delegated authority for air quality planning purposes, these proposed emission guidelines would require that planning requirements be met and emission management implementation plans be executed by the tribes. The EPA is aware of three coal-fired EGUs and one natural gas-fired EGU located in Indian country but is not aware of any affected EGUs that are owned or operated by tribal entities. The EPA notes that this proposal does not directly impose specific requirements on EGU sources, including those located in Indian country, such as the three coal-fired EGUs and one natural gas-fired EGU, but provides guidance to any tribe with delegated authority to address CO_2 emissions from EGU sources found subject to section 111(d) of the CAA. Thus, Executive Order 13175 does not apply to this action.

The EPA conducted outreach to tribal environmental staff and offered consultation with tribal officials in developing this action. Because the EPA is aware of tribal interest in this proposed rule, prior to the April 13, 2012 proposal (77 FR 22392-22441), the EPA offered consultation with tribal officials early in the process of developing the proposed regulation to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for new and existing sources. In addition, on April 15, 2014, prior to proposal, the EPA met with Navajo Energy Development Group officials. For this proposed action for existing EGUs, a tribe that has one or more affected EGUs located in its area of Indian Country[179] would have the opportunity, but not the obligation, to establish a CO_2 performance standard and a CAA section 111(d) plan for its area of Indian country.

Consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA's development of both the NSPS and emission guidelines for fossil fuel-fired EGUs and offered consultation. No tribes have requested consultation. Tribes were invited to

[179] The EPA is aware of at least four affected EGUs located in Indian country: two on Navajo lands, the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands, the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

participate in the national informational webinar held August 27, 2013. In addition, consultation/outreach meeting was held on September 9, 2013, with tribal representatives from some of the 584 tribes. The EPA also met with tribal environmental staff via National Tribal Air Association teleconferences on July 25, 2013, and December 19, 2013. In those teleconferences, the EPA provided background information on the GHG emission guidelines to be developed and a summary of issues being explored by the agency. Tribes have expressed varied points of view. Some tribes raised concerns about the impacts of the regulations on EGUs and the subsequent impact on jobs and revenue for their tribes. Other tribes expressed concern about the impact the regulations would have on the cost of water to their communities as a result of increased costs to the EGU that provide energy to transport the water to the tribes. Other tribes raised concerns about the impacts of climate change on their communities, resources, life ways and hunting and treaty rights. The tribes were also interested in the scope of the guidelines being considered by the agency (e.g., over what time period, relationship to state and multi-state plans) and how tribes will participate in these planning activities. In addition, the EPA held a series of listening sessions prior to development of this proposed action. In 2013, tribes participated in a session with the state agencies, as well as a separate session with tribes.

During the public comment period for this proposal, the EPA will hold meetings with tribal environmental staff to inform them of the content of this proposal, as well as offer further consultation with tribal elected officials where it is appropriate. We specifically solicit comment from tribal officials on this proposed rule.

CHAPTER 8: COMPARISON OF BENEFITS AND COSTS

8.1 Comparison of Benefits and Costs

The benefits, costs, and net benefits of the Option 1 and Option 2 illustrative compliance scenarios are presented in this chapter of the Regulatory Impact Analysis (RIA). As discussed in Chapter 1, the EPA is proposing two options for state-specific rate-based CO_2 goals that reflect application of measures from four building blocks. For both Options 1 and 2, two illustrative compliance scenarios, reflecting possible compliance approaches with state-specific CO_2 goals, are analyzed in this RIA. These scenarios are a reflection of what compliance could look like for Options 1 and 2, assuming states comply with the CO_2 goals on an individual state basis (referred to as state approach) or a number of states comply collectively on a regional basis (referred to as regional approach). EPA is proposing Option 1 and taking comment on Option 2. The guidelines allow flexibility of compliance, and EPA recognizes that actual compliance may differ from the illustrative approaches analyzed in this RIA.

The EPA has used the social cost of carbon estimates presented in the 2013 Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (2013 SCC TSD) to analyze CO_2 climate impacts of this rulemaking.[180] We refer to these estimates, which were developed by the U.S. government, as "SCC estimates." The SCC is an estimate of the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year). The four SCC estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this comparison of benefits and costs, the EPA provides the estimate of climate benefits associated with the SCC value deemed to be

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[180] Docket ID EPA-HQ-OAR-2013-0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised November 2013). Available at: http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.

central in the SCC TSD (the model average at 3% discount rate). As Table 8-1 shows, the EPA estimates that under the proposed Option 1, regional approach monetized climate benefits (in 2011$) are $17 billion in 2020, assuming a 3 percent discount rate (model average). The air pollution health co-benefits in 2020 are estimated to be $16 billion to $37 billion for a 3 percent discount rate and $15 billion to $34 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand side energy efficiency program and participant costs and monitoring, reporting, and recordkeeping (MRR) costs, are approximately $5.5 billion (2011$) in 2020. The quantified net benefits (the difference between monetized benefits and costs) in 2020, are $28 billion to $49 billion using a 3 percent discount rate and $26 billion to $45 billion assuming a 7 percent discount rate (2011$). In comparison, net benefits for the Option 1 state compliance approach in 2020 are estimated to be $27 billion to $50 billion, using a 3 percent discount rate and $26 billion to $46 billion assuming a 7 percent discount rate. Option 2 regional and state compliance approach benefits, costs and net benefits for 2020 are also shown on Table 8-1. Table 8-2 reflects estimates for the Options 1 and 2 regional and state compliance approaches for 2025. For the regional compliance approach to the proposal Option 1 in 2030, the EPA estimates this approach will yield monetized climate benefits of $30 billion (2011$) (using 3 percent discount rate (model average) as shown on Table 8-3.

In addition to CO_2, implementing these proposed guidelines is expected to reduce emissions of SO_2 and NO_X, which are precursors to formation of ambient $PM_{2.5}$, as well as directly emitted fine particles. Therefore, reducing these emissions would also reduce human exposure to ambient $PM_{2.5}$ and ozone precursors, thus the incidence of $PM_{2.5}$- and ozone related health effects. These air pollution health co-benefits in 2030 are estimated to be $25 billion to $59 billion for a 3 percent discount rate and $23 billion to $54 billion (2011$) for a 7 percent discount rate. The annual illustrative compliance costs estimated using IPM, inclusive of demand side energy efficiency program and participant costs and MRR costs, are approximately $7.3 billion (2011$) in 2030. The quantified net benefits for the Option 1 regional in 2030 are $48 billion to $82 billion, assuming a 3 percent discount rate, and $46 to $77 billion assuming a 7 percent discount rate (2011$). In 2030, quantified net benefits are $49 billion to $84 billion, assuming a 3 percent discount rate, and $46 to $79 billion assuming a 7 percent discount rate

(2011$) for the Option 1 state compliance approach..

Based upon the foregoing discussion, it remains clear that this proposal’s combined climate benefits and human health co-benefits associated with the reduction in other air pollutants substantial and far outweigh the compliance costs for all of the regulatory options and compliance approaches. The EPA could not monetize important categories of impacts. Unquantified impacts include those associated with changes in emissions of other pollutants that affect the climate, such as methane. In addition, the analysis does not quantify co-benefits from reducing exposure to SO_2, NOx, and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment.

Table 8-1. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines – 2020 (billions of 2011$) [a]

	Option 1 - state		Option 2 – state	
	3% Discount Rate	7% Discount Rate	3% Discount Rate	7% Discount Rate
Climate Benefits [b]				
5% discount rate	$4.9		$3.8	
3% discount rate	$18		$14	
2.5% discount rate	$26		$20	
95th percentile at 3% discount rate	$52		$40	
Air pollution health co-benefits [c]	$17 to $40	$15 to $36	$14 to $32	$12 to $29
Total Compliance Costs [d]	$7.5		$5.5	
Net Benefits [e]	$27 to $50	$26 to $46	$22 to $40	$20 to $37
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 1.5 tons of Hg Ecosystem effects Visibility impairment		Direct exposure to SO_2 and NO_2 1.2 tons of Hg Ecosystem effects Visibility impairment	
	Option 1 – regional		Option 2 – regional	
	3% Discount Rate	7% Discount Rate	3% Discount Rate	7% Discount Rate
Climate Benefits [b]				
5% discount rate	$4.7		$3.6	
3% discount rate	$17		$13	
2.5% discount rate	$25		$19	
95th percentile at 3% discount rate	$51		$39	
Air pollution health co-benefits [c]	$16 to $37	$15 to $34	$13 to $31	$12 to $28
Total Compliance Costs [d]	$5.5		$4.3	
Net Benefits [e]	$28 to $49	$26 to $45	$22 to $40	$21 to $37
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 1.3 tons of Hg Ecosystem effects Visibility impairment		Direct exposure to SO_2 and NO_2 0.9 tons of Hg Ecosystem effects Visibility impairment	

[a] All estimates are for 2020, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimates in this summary table reflect global impacts from CO_2 emission changes and do not account for changes in non-CO_2 GHG emissions. Different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume 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.

[d] Total social costs are approximated by the illustrative compliance costs estimated, in part, using the Integrated Planning Model for the proposed option and a discount rate of approximately 5%. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

Table 8-2. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines – 2025 (billions of 2011$) [a]

	Option 1 – state		Option 2 – state	
	3% Discount Rate	7% Discount Rate	3% Discount Rate	7% Discount Rate
Climate Benefits [b]				
5% discount rate	$7.6		$5.6	
3% discount rate	$25		$19	
2.5% discount rate	$37		$28	
95th percentile at 3% discount rate	$77		$57	
Air pollution health co-benefits [c]	$23 to $54	$21 to $49	$18 to $41	$16 to $37
Total Compliance Costs [d]	$5.5		$5.5	
Net Benefits [e]	$43 to $74	$41 to $69	$31 to $55	$29 to $51
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 2.0 tons of Hg Ecosystem effects Visibility impairment		Direct exposure to SO_2 and NO_2 1.7 tons of Hg Ecosystem effects Visibility impairment	

	Option 1 – regional		Option 2 – regional	
	3% Discount Rate	7% Discount Rate	3% Discount Rate	7% Discount Rate
Climate Benefits [b]				
5% discount rate	$7.5		$5.5	
3% discount rate	$25		$18	
2.5% discount rate	$37		$27	
95th percentile at 3% discount rate	$76		$56	
Air pollution health co-benefits [c]	$23 to $53	$21 to $48	$17 to $40	$16 to $36
Total Compliance Costs [d]	$4.6		$4.5	
Net Benefits [e]	$43 to $74	$41 to $69	$31 to $54	$29 to $50
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 1.7 tons of Hg Ecosystem effects Visibility impairment		Direct exposure to SO_2 and NO_2 1.3 tons of Hg Ecosystem effects Visibility impairment	

[a] All estimates are 2025, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimates in this summary table reflect global impacts from CO_2 emission changes and do not account for changes in non-CO_2 GHG emissions. Different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume 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.

[d] Total social costs are approximated by the illustrative compliance costs estimated, in part, using the Integrated Planning Model for the proposed option and a discount rate of approximately 5%. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

Table 8-3. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines –2030 (billions of 2011$) [a]

	Option 1– state	
	3% Discount Rate	7% Discount Rate
Climate Benefits [b]		
5% discount rate	$9.5	
3% discount rate	$31	
2.5% discount rate	$44	
95th percentile at 3% discount rate	$94	
Air pollution health co-benefits [c]	$27 to $62	$24 to $56
Total Compliance Costs [d]	$8.8	
Net Benefits [e]	$49 to $84	$46 to $79
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 2.1 tons of Hg and 590 tons of HCl Ecosystem effects Visibility impairment	
	Option 1– regional	
	3% Discount Rate	7% Discount Rate
Climate Benefits [b]		
5% discount rate	$9.3	
3% discount rate	$30	
2.5% discount rate	$44	
95th percentile at 3% discount rate	$92	
Air pollution health co-benefits [c]	$25 to $59	$23 to $54
Total Compliance Costs [d]	$7.3	
Net Benefits [e]	$48 to $82	$46 to $77
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 1.7 tons of Hg and 580 tons of HCl Ecosystem effects Visibility impairment	

[a] All estimates are 2030, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimates in this summary table reflect global impacts from CO_2 emission changes and do not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume 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.

[d] Total social costs are approximated by the illustrative compliance costs estimated, in part, using the Integrated Planning Model for the proposed option and a discount rate of approximately 5%. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

8.2 Uncertainty Analysis

The Office of Management and Budget's circular *Regulatory Analysis* (Circular A-4) provides guidance on the preparation of regulatory analyses required under E.O. 12866, and requires an uncertainty analysis for rules with annual benefits or costs of $1 billion or more.[181] This proposed rulemaking surpasses that threshold for both benefits and costs. Throughout the RIA, we considered a number of sources of uncertainty, both quantitatively and qualitatively, on benefits and costs. We summarize three key elements of our analysis of uncertainty here:

- Evaluating uncertainty in the compliance approaches that states will implement under Option 1 or Option 2, which influences both costs and benefits.
- Assess uncertainty in the methods used to calculate the health co-benefits associated with the reduction in $PM_{2.5}$ and ozone and the use of a benefits-per-ton approach in estimating these co-benefits.
- Characterizing uncertainty in the monetization of climate related benefits.

Some of these elements are evaluated using probabilistic techniques, whereas for others the underlying likelihoods of certain outcomes are unknown and so we use scenario analysis to evaluate their potential effect on the benefits and costs of this rulemaking.

8.2.1 Uncertainty in Abatement Costs and Compliance Approaches

The calculation of the state goals is based on an evaluation of methods for reducing the carbon emissions intensity of electricity generation that may be achieved at reasonable cost. Our best estimates of the costs of these methods of intensity reduction are reported within the cost analysis of this rule and are included in the cost modeling in the RIA (e.g., the cost of demand-side energy efficiency programs and non-emitting generation). We have also conducted cost analyses for alternative quantifications of the degree to which the building blocks of the BSER determination can reduce the carbon emissions intensity of electricity generation, and scenarios

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[181] Office of Management and Budget (OMB), 2003, *Circular A-4*, http://www.whitehouse.gov/omb/circulars_a004_a-4 and OMB, 2011. *Regulatory Impact Analysis: A Primer.* http://www.whitehouse.gov/sites/default/files/omb/*inforeg*/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf

modeled and presented in this RIA illustrate the potential range of impacts of the varying specifications of building block potential between Option 1 and Option 2 scenarios. Comments received by EPA on this proposal will have the potential to shed light on some of the uncertain components associated with the cost of technologies or other methods of reducing emissions intensity and will inform the basis of analyses in the final rule. However, we recognize that systematic uncertainty will persist in the analysis even with this additional information and analysis, especially given the state-level flexibility in meeting the guidelines.

A significant source of uncertainty under this regulation is the ultimate approach states will take to comply with the guidelines, which will affect both the costs and benefits of this rule. For this reason we modeled two potential compliance scenarios for each regulatory option: the state scenario and the regional scenario. In general, for both Option 1 and Option 2, the compliance cost of the regulation fell under the regional scenario as compared to the state scenario, while the reductions of CO_2 and other pollutants from fossil fuel combustion also fell (but by lesser proportions). However, from this analysis we see that the net benefits of the two scenarios, given consistent assumptions, do not differ notably.

8.2.2 Uncertainty Associated with $PM_{2.5}$ and Ozone Health Co-Benefits Assessment

Our estimate of the total monetized co-benefits is based on EPA's interpretation of the best available scientific literature and methods and supported by the SAB-HES and the National Academies of Science (NRC, 2002). Below are key assumptions underlying the estimates for $PM_{2.5}$-related premature mortality, which accounts for 98 percent of the monetized $PM_{2.5}$ health co-benefits.

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

- We assume that the health impact function for fine particles is log-linear without a threshold in this analysis. Thus, the estimates include health co-benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both areas that do not meet the fine particle standard and those areas that are in attainment, down to the lowest modeled concentrations.
- We assume that there is a "cessation" lag between the change in PM exposures and the total realization of changes in mortality effects. Specifically, we assume that some of the incidences of premature mortality related to $PM_{2.5}$ exposures occur in a distributed fashion over the 20 years following exposure based on the advice of the SAB-HES (U.S. EPA-SAB, 2004c), which affects the valuation of mortality co-benefits at different discount rates.EPA quantitatively assessed uncertainty in the air pollution health co-benefits, including probabilistic approaches.

As a further example, EPA provides the 95th percentile confidence interval for avoided PM-related premature deaths and the associated economic valuation using two key epidemiology studies. Further, EPA provides the PM-related results using alternate concentration-response relationship provided by an expert elicitation and alternate ozone-related results using concentration-response relationships provided by alternate epidemiology studies. Additional quantitative analyses include sensitivity analyses for alternate income growth adjustments and cessation lags, assessments of the distribution of population exposure in the modeling underlying the benefit-per-on estimates, and a quantitative evaluation of the benefit-per-ton estimates relative to recent analyses. A qualitative description of uncertainties associated with certain assumptions for PM, such as the linear model and equal potency across constituents, is also provided. For further discussion and characterization of those uncertainties influencing the benefit assessment, see Chapter 4.

As noted and described in Chapter 4, we use a benefit-per-ton approach to quantify health co-benefits. All benefit-per-ton have inherent limitations, including that the estimates reflect the geographic distribution of the modeled sector emissions, which may not match the emission reductions anticipated by the proposed guidelines, and they may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. In addition, these estimates reflect the regional average benefit-per-ton for each ambient $PM_{2.5}$ precursor emitted from EGUs, which assumes a linear atmospheric response to emission reductions. The regional benefit-per-ton estimates, although less subject to these types of uncertainties than national estimates, still should be interpreted with caution. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure.

8.2.3 Uncertainty Associated with Estimating the Social Cost of Carbon

The 2010 SCC TSD noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Current integrated assessment models do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. The limited amount of research linking climate impacts to economic damages makes the modeling exercise even more difficult. These individual limitations do not all work in the same direction in terms of their influence on the SCC estimates, though taken together they suggest that the SCC estimates are likely conservative. In particular, the IPCC Fourth Assessment Report (2007) concluded that "It is very likely that [SCC estimates] underestimate the damage costs because they cannot include many non-quantifiable impacts."

EPA characterized significant sources of uncertainty in the estimate of climate benefits of the emission reductions forecast by the compliance cost modeling.[182] The modeling underlying

[182] As discussed in Chapter 4, EPA estimated the global social benefits of CO_2 emission reductions expected from the proposed guidelines using the SCC estimates presented in the 2013 *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (2013 SCC TSD). The estimates were first developed by the U.S. government and published in the 2010 *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency*

the development of the SCC estimates addressed uncertainty in several ways. Three integrated assessment models (IAMs) were used to generate the SCC estimates. Each IAM relied on Monte Carlo simulations specifying different possible outcomes for climate sensitivity (represented by a Roe and Baker Distribution), used five different emissions growth scenarios and three discount rates. The distribution of results were depicted by four point estimates. The use of this range of point estimates in this rulemaking helps to reflect the uncertainty in the SCC estimation exercise. See both the 2010 SCC TSD and 2013 SCC TSD for a full description.

Working Group on Social Cost of Carbon (2010 SCC TSD) and updated in the 2013 SCC TSD. We refer to these estimates as "SCC estimates."

Chapter 9: Benefits, Costs, and Economic Impacts of Standards of Performance for Reconstructed and Modified Electric Utility Generating Units

9.1 Introduction

The U.S. Environmental Protection Agency (EPA) is proposing emission limits for carbon dioxide (CO_2) emitted from reconstructed and modified electric utility generating units (EGUs) under section 111(b) of the Clean Air Act (CAA). This chapter presents the proposed standards of performance for reconstructed and modified EGUs, as well as the expected economic impacts of the proposed standards. Based on historical information that has been reported to the EPA, the EPA anticipates few covered units will trigger the reconstruction or modification provisions in the period of analysis (through 2025). As a result, we do not anticipate any significant costs or benefits associated with this proposal. However, because there have been a few units that have notified EPA of modifications in the past, in this chapter we present an illustrative analysis of the costs and benefits for a hypothetical unit if it were to trigger the modification provision. We also discuss how the costs and benefits for compliance with the proposed standards may vary as a result of interactions with the CAA 111(d) emission guidelines for existing sources. This chapter also presents the relevant executive order and statutory requirements related to this proposal.

9.2 Legal Basis for this Rulemaking

Section 111 of the CAA requires performance standards for air pollutant emissions from categories of stationary sources that may reasonably contribute to the endangerment of public health or welfare. In April 2007, the Supreme Court ruled in *Massachusetts* v. *EPA* that greenhouse gases (GHGs) meet the definition of an "air pollutant" under the CAA. This ruling clarified that the authorities and requirements of the CAA apply to GHGs. The EPA issued a final determination that GHG emissions endanger both the public health and the public welfare of current and future generations in the Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the CAA (74 FR 66,496; Dec. 15, 2009).

On September 20, 2013, the EPA announced its first steps under President Obama's Climate Action Plan to reduce CO_2 emissions from power plants by proposing standards for newly constructed power plants built in the future (79 FR 1430, January 8, 2014). Specifically, under the authority of CAA section 111(b), the EPA proposed standards for emissions of CO_2 from newly constructed utility boilers and integrated gasification combined cycle (IGCC) units, and for natural gas-fired stationary combustion turbines. This action proposes standards to address CO_2 emissions from reconstructed and modified power plants under the authority of CAA section 111(b).

9.3 Background for the Proposed EGU Reconstructed and Modified Source GHG Standards

9.3.1 Definition of Affected Sources

This action proposes emission limits for EGUs that undergo reconstruction or modification. This rulemaking does not address GHG emissions from newly constructed sources or existing sources that do not undertake reconstruction or modification. (Analysis of the impact of emission guidelines for existing sources is presented in the preceding chapters.) The EPA is proposing that an existing unit that becomes subject to requirements under section 111(d) will continue to be subject to those requirements even after it becomes a modified or reconstructed source. Under this interpretation, the modified or reconstructed source would be subject to both the section 111(d) requirements that it had previously been subject to and the modified or reconstructed source standard under 111(b) that it became subject to as a modified or reconstructed source.

9.3.1.1 Reconstructed Sources

Under the EPA's CAA section 111 standards of performance for new stationary sources, reconstructed sources are defined, in general, as existing sources that replace components to such an extent that the capital costs of the new components exceed 50 percent of the capital costs of an entirely new facility, and for which compliance with standards of performance for newly constructed sources is technologically and economically feasible. As described in the preamble, determinations regarding reconstructed status are made on a case-by-case basis, based on information submitted regarding the planned project.

9.3.1.2 Modified Sources

A modification is any physical or operational change to a source that increases the source's maximum achievable hourly rate of emissions (i.e., lbs/hour). The EPA, through regulations, has determined that certain types of changes (such as pollution control projects) are exempt from consideration as a modification (40 CFR 60.2, 60.14(e)).

9.3.2 Emission Limits

This action proposes standards of performance for reconstructed utility boilers and IGCC units based on current best-performing generating technology (e.g., use of the highest demonstrated steam temperatures and pressures) as the best system of emission reductions (BSER). This action also proposes standards of performance for reconstructed natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle (NGCC) technology as the BSER. The proposed emission limits are calculated on a 12-month rolling average basis. The proposed emission limits for these units are shown in table 9-1. All existing sources that reconstruct after becoming subject to an approved CAA 111(d) state plan will remain in the plan and remain subject to regulatory requirements in the plan in addition to its regulatory requirements as a reconstructed unit.

Table 9-1. Proposed Emission Limits - Reconstructions

Subcategory	Emission Limit
Reconstructed Utility Boilers and IGCC Units (heat input rating > 2,000 MMBtu/h)	1,900 lb CO_2/MWh-net
Reconstructed Utility Boilers and IGCC Units (heat input rating <= 2,000 MMBtu/h)	2,100 lb CO_2/MWh-net
Reconstructed Natural Gas-Fired Stationary Combustion Turbines (heat input rating > 850 MMBtu/h)	1,000 lb CO_2/MWh-gross
Reconstructed Natural Gas-Fired Stationary Combustion Turbines (heat input rating <= 850 MMBtu/h)	1,100 lb CO_2/MWh-gross

This action proposes that modified utility boilers and IGCC units must meet one of two alternative requirements, depending on the timing of the modification.[183] Sources that modify

[183] Units triggering both the modification and reconstruction provisions would be subject to the reconstructed source standards.

prior to becoming subject to an approved section 111(d) state plan would be required to meet a unit-specific numerical emission standard that is based on the source's best demonstrated historical performance. Specifically, a modified utility boiler or IGCC unit would be required to maintain an emission rate that is two percent less than the unit's best demonstrated annual performance during the years from 2002 to the year the modification occurs (or the emission limitation applicable to a corresponding reconstructed source, whichever is less stringent). The EPA has determined that this standard can be met through a combination of best operating practices and equipment upgrades. In co-proposed alternative #2, existing utility boilers and IGCC units that modify after becoming subject to requirements under an approved 111(d) plan would be required to meet a unit-specific emission limitation that is determined from a third party assessment to identify energy efficiency improvement opportunities for the affected source.[184] All existing sources that are subject to requirements under an approved section 111(d) plan would remain subject to those requirements after modifying.

For affected modified natural gas-fired stationary combustion turbines not subject to a 111(d) plan, this action proposes standards of performance based on efficient NGCC technology as the BSER. The EPA is also proposing that affected stationary combustion turbines that are subject to an approved section 111(d) plan must remain in the plan. The proposed emission limits for modified sources (for co-proposed alternative #2) are shown in Table 9-2.

[184] In co-proposed alternative #1, units would be required to meet the same 111(b) standard both before and after participation in a state 111(d) program.

Table 9-2. Proposed Emission Limits - Modifications

	Subcategory	Emission Limit
Not Subject to State CAA 111(d) Plan	Modified Utility Boilers and IGCC Units (heat input rating > 2,000 MMBtu/h)	2% less than unit's best demonstrated annual performance NO LOWER THAN 1,900 lb CO_2/MWh-net
	Modified Utility Boilers and IGCC Units (heat input rating <= 2,000 MMBtu/h)	2% less than unit's best demonstrated annual performance NO LOWER THAN 2,100 lb CO_2/MWh-net
	Modified Natural Gas-Fired Stationary Combustion Turbines (heat input rating > 850 MMBtu/h)	1,000 lb CO_2/MWh-gross
	Modified Natural Gas-Fired Stationary Combustion Turbines (heat input rating <= 850 MMBtu/h)	1,100 lb CO_2/MWh-gross
After Becoming Subject to State CAA 111(d) Plan	Modified Utility Boilers and IGCC Units	Unit-specific emission limit determined by the expected performance after implementation of identified energy efficiency improvement opportunities AND 111(d) requirements
	Modified Natural Gas-Fired Stationary Combustion Turbines (heat input rating > 850 MMBtu/h)	1,000 lb CO_2/MWh-gross AND 111(d) requirements
	Modified Natural Gas-Fired Stationary Combustion Turbines (heat input rating <= 850 MMBtu/h)	1,100 lb CO_2/MWh-gross AND 111(d) requirements

Note: The proposed emission limits are calculated on a 12-month rolling average basis.

9.4 Impacts of the Proposed Reconstructed and Modified Source Standards

9.4.1 Reconstructed Sources

Historically, we are only aware of one EGU that has notified the EPA that it has reconstructed under the reconstruction provision of section 111(b). As a result, we anticipate that few EGUs will undertake reconstruction through 2025. For this reason, the proposed standards will not result in any significant emission reductions, costs, or quantified benefits in the period of analysis. Likewise, the Agency does not anticipate any impacts on the price of electricity or energy supply. The proposed rule is not expected to raise any resource adequacy concerns, since reserve margins will not be impacted and the rule does not impose any additional requirements on existing facilities not triggering the reconstruction provision. There are no macroeconomic or employment impacts expected as a result of these proposed standards.

Due to the extremely limited data available on reconstructions, it is not possible to conduct a representative illustrative analysis of what costs and benefits might result from this proposal in the unlikely case that a unit were to reconstruct.

9.4.2 Modified Sources

Historically, few EGUs have notified the EPA that they have modified under the modification provision of section 111(b). The EPA's current regulations define an NSPS "modification" as a physical or operational change that increases the source's maximum achievable hourly rate of emissions, but specifically exempt from that definition projects that entail the installation of pollution control equipment or systems. The EPA expects that most of the actions EGUs are likely to take in the foreseeable future that would be classified as "modifications" would qualify as pollution control projects. In many cases, those projects would involve the installation of add-on control equipment needed to meet CAA requirements for criteria and air toxics air pollutants. Any associated CO_2 emissions increases would generally be small and would occur as a chemical byproduct of the operation of the control equipment. In other cases, those projects would involve equipment changes to improve fuel efficiency to meet state requirements for implementation of the future CAA section 111(d) rulemaking for existing sources and would have the effect of increasing a source's maximum achievable hourly emission rate (lb CO_2/hr), even while decreasing its actual output based emission rate (lb CO_2/MWh). Because all of these actions would be treated as pollution control projects under the EPA's current NSPS regulations, they would be specifically exempted from the definition of modification.

Based on this information, we anticipate that few EGUs will take actions that would be considered modifications during the period of analysis. For this reason, the proposed standards will result in minimal emission reductions, costs, or quantified benefits by 2025. Likewise, the Agency does not anticipate any impacts on the price of electricity or energy supplies. This proposed rule is not expected to raise any resource adequacy concerns, since reserve margins will not be impacted and the rule does not impose any additional requirements on existing facilities not triggering the modification provision. There are no macroeconomic or employment impacts expected as a result of these proposed standards.

9.4.2.1 Illustrative Analysis – Emission Reductions

In the unlikely event that a unit were to trigger the modification provision, the proposed standards would result in some costs and benefits. Based on available data, we conducted an analysis of a hypothetical unit to illustrate the potential costs and benefits of the proposed standards. The hypothetical plant presented in this section is a coal-fired boiler[185] and is assumed to be in compliance with all on-the-books federal regulations. In the illustrative analysis, costs and benefits are presented for compliance in 2025. Section 111(b) standards are subject to review every eight years. While we do not know when the hypothetical plant would choose to undertake a modification, it is necessary to select a year of analysis in order to value the climate benefits and health co-benefits resulting from these proposed standards. We have selected 2025 to approximate the end of the eight year period. All estimates are presented in 2011 dollars.

The hypothetical unit used in this analysis is a 33 percent efficient 500 MW bituminous coal-fired unit operating at 78 percent capacity. The assumptions for capacity and efficiency were based on the average projected coal fleet in IPM in 2020. The emission rate specifications are (1) SO_2 = 0.30 lb/MMBtu (3.3% weight Illinois bituminous coal with 95% efficient scrubber), (2) NO_X = 0.30 lb/MMBtu (low NO_X burners plus overfire air and SNCR), and (3) $PM_{2.5}$ = 0.024 lb/MMBtu (8 lb/MMBtu ash with 99.7% control). In this analysis, we examine the costs and benefits that would occur if this unit were able to make a 4 percent, 6 percent, or 8 percent heat rate improvement as a result of measures implemented in order to comply with the proposed standards for modified sources.

[185] IGCC and NGCC units are significantly less likely to trigger the modification provision due to the way in which these units are constructed. Simple-cycle combustion turbines (CT) have lower fuel efficiencies and produce a significantly higher cost of electricity (cost per kWh) at higher capacity factors and consequently are typically utilized at levels well below the proposed threshold for covered sources (1/3 of potential electric output). Historically, these units have most often been built to ensure reserve margins are met during peak periods (typically in the summer), and in some instances are able to generate additional revenues by selling capacity into power markets. Thus, in practice, EPA expects that potential CT units would not meet the applicability threshold in this proposed action and would not be subject to any standard. During the public comment period for the proposed 111(b) standards for newly constructed sources, the EPA has received comments regarding more recent integration of CT units and renewables and is taking comment on the treatment of these units.

Costs. We assume the hypothetical unit will implement a range of energy efficiency improvements at an annual cost of $8.3 million.[186] At this cost, we estimate the typical unit would be able to implement a set of efficiency improvement measures that would achieve a heat rate improvement of approximately 6 percent. A heat rate improvement of 6 percent is approximately equivalent to an absolute efficiency improvement of 2 percent. The actual efficiency improvement a unit can achieve for this cost will depend on its starting efficiency and operating capacity. Less efficient units may have more efficiency improvement options available and be able to achieve greater efficiency for the same cost. Relatively more efficient units may have fewer remaining cost-effective options to improve efficiency. Improvements in efficiency will result in fuel savings, which can offset the cost of implementing those improvements. Cost and fuel savings information is shown in Table 9-3.

For units that modify prior to being part of a section 111(d) existing source program that choose to comply with a source-specific standard that is a 2 percent improvement from the previous best performance, costs will vary depending on the current and prior performance of that unit. For a unit that modifies after being covered by a section 111(d) program, it is possible that the energy assessment may not identify any further efficiency improvements that unit can economically undertake considering the overall 111(d) program requirements. In those cases, there would be no additional control costs to the unit as a result of this proposal.

[186] Calculated based on a total capital cost of $50 million ($100/kilowatt), financed over 15 years at a capital charge rate of 14.29%. The capital charge rate value and useful life are based on assumptions used when modeling the electricity sector in the Integrated Planning Model (IPM). Please see Chapter 8 of EPA's documentation for the IPM for more information on the assumed capital charge rate: http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_8.pdf. See the See Technical Support Document – GHG Abatement Measures" for information about the cost of efficiency improvements.

Table 9-3. Annualized Costs and Fuel Savings of Efficiency Improvements (millions of 2011$)

	4% Efficiency Improvement	6% Efficiency Improvement	8% Efficiency Improvement
Annual Cost	$8.3	$8.3	$8.3
Fuel Savings	$3.7	$5.6	$7.5
Net Cost	$4.5	$2.6	$0.78

Emission Reductions. By improving the efficiency of its operations, the hypothetical unit would reduce emissions of CO_2 and may reduce emissions of (SO_2), nitrogen dioxide (NOx), and fine particulate matter ($PM_{2.5}$), which would lead to lower ambient concentrations of $PM_{2.5}$ and ozone. Table 9-4 shows the expected emission reductions from each level of efficiency improvement for the hypothetical unit. For a unit participating in a 111(d) plan, it is possible that the CO_2 emission reductions could be offset by increases elsewhere in the system depending on the structure of that plan. Ancillary emission reductions may be offset if, as a result of these reductions, a unit is able to reduce operation of pollution control equipment and still meet output-based standards for these pollutants or pollutants related to their control (such as the Mercury and Air Toxics Standards limit for SO_2 to control hydrogen chloride). Additionally, if efficiency improvements lead to decreased operating costs, it may result in changes to the frequency of dispatch for the unit. In that case, the unit may run more often, offsetting some of the emission decreases. Furthermore, for units that choose to comply with a source-specific standard that is a 2 percent improvement from the previous best performance, emission reductions will vary depending on the current and prior performance of that unit. Additionally, it is possible that the energy assessment for a unit participating in a 111(d) program may not identify any further fuel efficiency improvements that unit can economically undertake after implementing the overall 111(d) program requirements. In those cases, there would be no additional emission reductions or control costs as a result of this proposal.

Table 9-4. Emission Reductions from Efficiency Improvements (tons/year)

	4% Efficiency Improvement	6% Efficiency Improvement	8% Efficiency Improvement
CO_2	132,790	199,184	265,579
SO_2	214	321	428
NO_x (Total)	214	321	428
NO_x (Ozone Season)	89	134	178
$PM_{2.5}$	17	26	34

Notes: SO_2, NO_X, and $PM_{2.5}$ in short tons, CO_2 in metric tonnes.

Benefits. Reducing CO_2 and criteria pollutant emissions will result in both climate and human health benefits. The impacts of these pollutants on the environment and health are discussed in detail in Chapter 4 of this RIA. In sum, to estimate climate benefits the EPA uses the U.S. government's global social cost of carbon (USG SCC) estimates—i.e, the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year. The EPA has applied the USG SCC estimates to the CO_2 reductions described above for the hypothetical unit. The four USG SCC estimates are as follows: \$15, \$50, \$74, and \$153 per metric ton of CO_2 emissions in the year 2025 (2011\$). To estimate human health co-benefits for this hypothetical scenario, the EPA used benefit-per-ton estimates for $PM_{2.5}$ and ozone precursors described in detail in Chapter 4 of this RIA. Table 9-5 shows the quantified per ton co-benefits for reductions in SO_2, directly emitted $PM_{2.5}$, and NO_X emissions in 2025.

Table 9-5. Summary of National Benefit-per-ton (BPT) Estimates for EGUs in 2025

	Discount Rate	
Pollutant	3%	7%
SO_2	\$41,000 to \$93,000	\$37,000 to \$84,000
Directly emitted $PM_{2.5}$ (EC+OC)	\$150,000 to \$350,000	\$140,000 to \$310,000
Directly emitted $PM_{2.5}$ (crustal)	\$17,000 to \$39,000	\$15,000 to \$35,000
NO_X (as $PM_{2.5}$)	\$6,000 to \$14,000	\$5,400 to \$12,000
NO_X (as Ozone)*	\$4,900 to \$21,000	

* Ozone co-benefits occur in analysis year, so they are the same for all discount rates.
Note: See section 4.3.6 for discussion of the assumptions, and uncertainty for these estimates.

To estimate the benefits associated with improving efficiency of operations, we determine the emission reductions for efficiency improvements in Table 9-4 and apply the 2025 social benefit values discussed in Chapter 4. Specifically, we multiply the reduction in CO_2 emissions by the estimates of the SCC, multiply the reduction in SO_2, NO_X, and $PM_{2.5}$ emissions by the $PM_{2.5}$-related BPT estimates, multiply the reductions in ozone season NO_X emissions by the ozone-related BPT estimate, and add those values to get a measure of 2025 benefits. Tables 9-6, 9-7, and 9-8 show the climate, human health, and combined benefits expected based on the estimated emission reductions that would occur. These benefits are subject to the same uncertainties discussed for emission reductions in the previous section.

Table 9-6. Estimated Global Climate Benefits of Illustrative CO_2 Reductions in 2025 (millions of 2011$)*

Discount Rate and Statistic	4% Efficiency Improvement	6% Efficiency Improvement	8% Efficiency Improvement
Metric tonnes of CO_2 reduced	132,790	199,184	265,579
5% (average)	$2.0	$3.0	$4.0
3% (average)	$6.7	$10	$13
2.5% (average)	$9.8	$15	$20
3% (95th percentile)	$20	$30	$41

* The SCC values are dollar-year and emissions-year specific. SCC values represent only a partial accounting of climate impacts.

Table 9-7. Summary of Estimated Monetized Health Co-benefits of Illustrative Efficiency Improvements in 2025 (thousands of 2011$)*

Pollutant	3% Discount Rate			7% Discount Rate		
4% Efficiency Improvement						
SO_2	$8,900	to	$20,000	$8,000	to	$18,000
Directly emitted $PM_{2.5}$ (EC+OC)	$260	to	$590	$240	to	$530
Directly emitted $PM_{2.5}$ (crustal)	$230	to	$510	$200	to	$460
NOx (as $PM_{2.5}$)	$1,300	to	$2,900	$1,200	to	$2,600
NOx (as Ozone)	$440	to	$1,900	$440	to	$1,900
Total	$11,000	to	$26,000	$10,000	to	$23,000
6% Efficiency Improvement						
SO_2	$13,000	to	$30,000	$12,000	to	$27,000
Directly emitted $PM_{2.5}$ (EC+OC)	$400	to	$900	$360	to	$810
Directly emitted $PM_{2.5}$ (crustal)	$350	to	$780	$310	to	$710
NOx (as $PM_{2.5}$)	$1,900	to	$4,300	$1,700	to	$3,900
NOx (as Ozone)	$660	to	$2,800	$660	to	$2,800
Total	$17,000	to	$39,000	$15,000	to	$35,000
8% Efficiency Improvement						
SO_2	$18,000	to	$40,000	$16,000	to	$36,000
Directly emitted $PM_{2.5}$ (EC+OC)	$520	to	$1,200	$470	to	$1,100
Directly emitted $PM_{2.5}$ (crustal)	$450	to	$1,000	$410	to	$930
NOx (as $PM_{2.5}$)	$2,600	to	$5,800	$2,300	to	$5,200
NOx (as Ozone)	$880	to	$3,800	$880	to	$3,800
Total	$22,000	to	$52,000	$20,000	to	$47,000

* All estimates are rounded to two significant figures so numbers may not sum down columns. The estimated monetized co-benefits do not include climate benefits or health effects from direct exposure to NO_2, SO_2, and hazardous air pollutants (HAP); ecosystem effects; or visibility impairment. All fine particles are assumed to have equivalent health effects. The monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. Co-benefits for $PM_{2.5}$ and ozone are based on national benefit-per-ton estimates. Co-benefits for ozone are based on ozone season NOx emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski et al. (2009) with Bell et al. (2004) to Lepeule et al. (2012) with Levy et al. (2005)). Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski et al. (2009) and Lepeule et al. (2012). Emissions of directly emitted particles are disaggregated into EC+OC or crustal components using the method discussed in Appendix 4A of this RIA.

Table 9-8. Combined Estimated Climate Benefits and Health Co-Benefits of Illustrative Efficiency Improvements in 2025 (millions of 2011$)*

SCC Discount Rate	Climate Benefits Only	Climate Benefits and Health Co-Benefits (Discount Rate Applied to Health Co-Benefits)	
		3%	7%
4% Efficiency Improvement	132,790	metric tonnes CO_2	
5%	$2.0	$13 to $28	$12 to $25
3%	$6.7	$18 to $33	$17 to $30
2.5%	$9.8	$21 to $36	$20 to $33
3% (95th percentile)	$20	$31 to $46	$30 to $44
6% Efficiency Improvement	199,184	metric tonnes CO_2	
5%	$3.0	$20 to $42	$18 to $38
3%	$10	$27 to $49	$25 to $45
2.5%	$15	$31 to $53	$30 to $50
3% (95th percentile)	$30	$47 to $69	$45 to $66
8% Efficiency Improvement	265,579	metric tonnes CO_2	
5%	$4.0	$26 to $56	$24 to $51
3%	$13	$35 to $65	$33 to $60
2.5%	$20	$42 to $71	$40 to $67
3% (95th percentile)	$41	$63 to $92	$61 to $88

*All estimates are rounded to two significant figures. Climate benefits are based on reductions in CO_2 emissions. The estimated monetized co-benefits do not include climate benefits or health effects from direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment. All fine particles are assumed to have equivalent health effects. The monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. Co-benefits for $PM_{2.5}$ and ozone are based on national benefit-per-ton estimates. Co-benefits for ozone are based on ozone season NOx emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski et al. (2009) with Bell et al. (2004) to Lepeule et al. (2012) with Levy et al. (2005)). Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski et al. (2009) and Lepeule et al. (2012). Emissions of directly emitted particles are disaggregated into EC+OC or crustal components using the method discussed in Appendix 4A of this RIA.

Summary. In the unlikely event that a unit were to trigger the modification provision, the proposed standards would result in some costs and benefits. Based on the illustrative analysis of a hypothetical unit implementing efficiency measures in 2025 to comply with the proposed requirements, this proposal would result in a net benefit (benefits outweigh costs) for all levels of efficiency improvement and combinations of benefits. The net benefit would be even greater when potential fuel savings are taken into account. The actual costs, emission reductions, and benefits resulting from this proposal will vary based on the specifications of the modified unit, the efficiency improvements undertaken, the unit's participation in a section 111(d) plan, and the influence of the control requirements it faces for non-CO_2 pollutants.

9.5 Statutory and Executive Order Requirements

9.5.1 Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order (EO) 12866 (58 FR 51,735, October 4, 1993), this action is a "significant regulatory action" because it "raises novel legal or policy issues arising out of legal mandates." Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is presented in the preceding sections of this chapter.

In the period of analysis (through 2025) the EPA anticipates few sources will trigger either the modification or the reconstruction provisions proposed. Because there have been a few units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit that is presented above.

9.5.2 Paperwork Reduction Act

This proposed action is not expected to impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. Burden is defined at 5 CFR 1320.3(b). As previously stated, the EPA expects few modified or reconstructed EGUs in the period of analysis. Specifically, the EPA believes it unlikely that fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines will take actions that would constitute modifications or reconstructions as defined under the EPA's NSPS regulations. Accordingly, this proposed action is not anticipated to impose any information collection burden over the 3-year period covered by the Information Collection Request (ICR) for this proposed rule. We have estimated, however, the information collection burden that would be imposed on an affected EGU if it was modified or reconstructed. The information collection requirements in this proposed rule have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The information collection request prepared by the EPA has been assigned the EPA ICR number 2465.03.

The EPA intends to codify the standards of performance in the same way for both this proposed action and the January 2014 proposal for newly constructed sources and is proposing the same recordkeeping and reporting requirements that were included in the January 2014 proposal.[187] (See 79 FR 1,498 and 1,499.) Although not anticipated, if an EGU were to modify or reconstruct, this proposed action would impose minimal information collection burden on affected sources, beyond what those sources would already be subject to under the authorities of CAA parts 75 and 98. The OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control numbers 2060-0626 and 2060-0629, respectively. Apart from potential energy metering modifications to comply with net energy output based emission limits proposed in this action and certain reporting costs, which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there would be no new information collection costs, as the information required by this proposed rule is already collected and reported by other regulatory programs. The recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). 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.

Although, as stated above, the EPA expects few sources will trigger either the NSPS modification or reconstruction provisions that we are proposing, if an EGU were to modify or reconstruct during the three-year period covered by the ICR, it is likely that the EGU's energy metering equipment would need to be modified to comply with proposed net energy output based CO_2 emission limits. Specifically, the EPA estimates that it would take approximately three working months for a technician to retrofit existing energy metering equipment to meet the proposed net energy output requirements. In addition, after modifications are made that enable a facility to measure net energy output, each EGU's Data Acquisition System (DAS) would need

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[187] The information collection requirements in the January 2014 proposal have been submitted for approval to the OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The ICR document prepared by the EPA for the January 2014 proposal has been assigned the EPA ICR number 2465.02.

to be upgraded to accommodate reporting of net energy output rate based emissions. A modified or reconstructed EGU would be required to prepare a quarterly summary report, which includes reporting of emissions and downtime, every three months. The reporting burden for such a unit (averaged over the first three years after the effective date of the standards) is estimate to be $17,217 and 205 labor hours. Estimated cost burden is based on 2013 Bureau of Labor Statistics (BLS) labor cost data. Average burden hours per response are estimated to be 47.3 hours and the average number of annual responses over the three-year ICR period is 4.33 per year. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes the ICR, under Docket ID number EPA-HQ-OAR-2013-0603. Submit any comments related to the ICR to the EPA and OMB. See the addresses section in the preamble for where to submit comments to the EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503, Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after publication in the Federal Register, a comment to OMB is best assured of having its full effect if OMB receives it by 30 days after publication in the Federal Register. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

9.5.3 Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as:

1. A small business that is defined by the SBA's regulations at 13 CFR 121.201 (for the electric power generation industry, the small business size standard is an ultimate parent entity with less than 750 employees).
2. A small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and
3. A small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed rule on small entities, we certify that this action will not have a significant economic impact on a substantial number of small entities.

The EPA expects few modified utility boilers, IGCC units, or stationary combustion turbines in the period of analysis. An NSPS modification is defined as a physical or operational change that increases the source's maximum achievable hourly rate of emissions. The EPA does not believe that there are likely to be EGUs that will take actions that would constitute modifications as defined under the EPA's NSPS regulations.

Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, the RIA for this proposed rule includes an illustrative analysis of the costs and benefits for a representative unit.

Based on the analysis, the EPA estimates that this proposed rule could result in CO_2 emission changes, quantified benefits, or costs for a hypothetical unit that triggered the modification provision. However, we do not anticipate this proposed rule would impose significant costs on those sources, including any that are owned by small entities.

In addition, the EPA expects few reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis. Reconstruction occurs when a single project replaces components or equipment in an existing facility and exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Due to the limited data available on reconstructions, it is not possible to conduct a representative illustrative analysis of what costs and benefits might result from this proposal in the unlikely case that a unit were to reconstruct. However, based on the low number of previous reconstructions and the BSER determination based on the most efficient available generating technology, we would expect this proposal to result in no significant CO_2 emission changes, quantified benefits, or costs for NSPS reconstructions.

Nevertheless, the EPA is aware that there is substantial interest in the proposed rule among small entities (municipal and rural electric cooperatives). As summarized in section II.G. of the preamble, the EPA has conducted an unprecedented amount of stakeholder outreach. As part of that outreach, agency officials participated in many meetings with individual utilities as well as meetings with electric utility associations. Specifically, the EPA Administrator, Gina McCarthy, participated in separate meetings with both the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA). The meetings brought together leaders of the rural cooperatives and public power utilities from across the country. The Administrator discussed and exchanged information on the unique challenges, in particular the financial structure of NRECA and APPA member utilities. A detailed discussion of the stakeholder outreach is included in the preamble to the emission guidelines for existing affected electric utility generating units being proposed in a separate action.

In addition, as described in the RFA section of the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1499 and 1500, January 8, 2014), the EPA conducted outreach to representatives of small entities while formulating the provisions of the proposed standards. Although only newly constructed EGUs would be affected by those proposed standards, the outreach regarded planned actions for newly constructed, reconstructed, modified and existing sources.

While formulating the provisions of the proposed rule, the EPA considered the input provided over the course of the stakeholder outreach. We invite comments on all aspects of this proposal and its impacts, including potential impacts on small entities.

9.5.4 Unfunded Mandates Reform Act (UMRA)

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. As previously stated, the EPA expects few modified or reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis. Accordingly, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

In light of the interest among governmental entities, the EPA initiated consultations with governmental entities while formulating the provisions of the proposed standards for newly constructed EGUs. This outreach regarded planned actions for newly constructed, reconstructed, modified and existing sources. As described in the UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1500 and 1501, January 8, 2014), the EPA consulted with the following 10 national organizations representing state and local elected officials:

- National Governors Association
- National Conference of State Legislatures
- Council of State Governments
- National League of Cities
- U.S. Conference of Mayors
- National Association of Counties
- International City/County Management Association
- National Association of Towns and Townships
- County Executives of America
- Environmental Council of State

On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs.

While formulating the provisions of these proposed standards, the EPA also considered the input provided over the course of extensive stakeholder outreach conducted by the EPA (see section II.G. of the preamble for more information).

9.5.5 Executive Order 13132, Federalism

This proposed action does not have federalism implications. It would not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. This proposed action would not impose substantial direct compliance costs on state or local governments, nor would it preempt state law. Thus, EO 13132 does not apply to this action.

However, as described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1501, January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. This outreach regarded planned actions for newly constructed, reconstructed, modified and existing sources. The EPA engaged 10 national organizations representing state and local elected officials. The UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1500 and 1501, January 8, 2014) includes a description of the consultation. In addition, on February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs. While formulating the provisions of these proposed standards, the EPA also considered the input provided over the course of the extensive stakeholder outreach conducted by the EPA (see section II.G. of the preamble). In the spirit of EO 13132, and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

9.5.6 Executive Order 13175, Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It would neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. This proposed rule would impose requirements on owners and operators of reconstructed and modified EGUs. The EPA is aware of three coal-fired EGUs located in Indian Country but is not aware of any EGUs owned or operated by tribal entities. The EPA notes that this proposal would only affect existing sources such as the three coal-fired EGUs located in Indian Country, if those EGUs were to take actions constituting modifications or reconstructions as defined under the EPA's NSPS regulations. However, as previously stated, the EPA expects few modified or reconstructed EGUs in the period of analysis. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, the EPA conducted outreach to tribal environmental staff and offered consultation with tribal officials in developing this action. Because the EPA is aware of tribal interest in carbon pollution standards for the power sector, prior to proposal of GHG standards for newly constructed power plants, the EPA offered consultation with tribal officials early in the process of developing the proposed regulation to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for newly constructed, reconstructed, modified, and existing sources. The Consultation and Coordination with Indian Tribal Governments discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1501, January 8, 2014) includes a description of that consultation.

During development of this proposed regulation, consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA's development of both the NSPS for modified and reconstructed EGUs and emission guidelines for existing EGUs and offered consultation. None have requested consultation. Tribes were invited to participate in the national informational webinar held August 27, 2013, and to which tribes were invited. In addition, a consultation/outreach meeting was held on September 9, 2013, with tribal representatives from some of the 584 tribes. The EPA also met with tribal environmental staff with the National Tribal Air Association, by teleconference, on July 25, 2013, and December 19,

2013. In those teleconferences, the EPA provided background information on the GHG emission guidelines to be developed and a summary of issues being explored by the Agency. Additional detail regarding this stakeholder outreach is included in the executive order discussion for the emission guidelines for existing affected electric utility generating units in Chapter 7 of this RIA. The EPA also held a series of listening sessions prior to proposal of GHG standards for newly constructed power plants. Tribes participated in a session on February 17, 2011, with state agencies, as well as in a separate session with tribes on April 20, 2011.

The EPA will also hold additional meetings with tribal environmental staff during the public comment period, to inform them of the content of this proposal, and offer further consultation with tribal elected officials where it is appropriate. We specifically solicit additional comment from tribal officials on this proposed rule.

9.5.7 Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks

The EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5-501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it is based solely on technology performance.

9.5.8 Executive Order 13211, Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not a "significant energy action" as defined in EO 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. As previously stated, the EPA expects few reconstructed or modified EGUs in the period of analysis and impacts on emissions, costs or energy supply decisions for the affected electric utility industry to be minimal as a result.

9.5.9 National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA of 1995 (Public Law No. 104-113; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs the EPA to provide Congress, through annual reports to the OMB, with explanations when an agency does not use available and applicable VCS.

This proposed rulemaking involves technical standards. The EPA proposes to use the following standards in this proposed rule:

- ASTM D388-12 (Standard Classification of Coals by Rank)
- ASTM D396-13c (Standard Specification for Fuel Oils)
- ASTM D975-14 (Standard Specification for Diesel Fuel Oils)
- D3699-13b (Standard Specification for Kerosene)
- D6751-12 (Standard Specification for Biodiesel Fuel Blend Stock [B100] for Middle Distillate Fuels)
- ASTM D7467-13 (Standard Specification for Diesel Fuel Oil, Biodiesel Blend [B6 to B20])
- ANSI C12.20 (American National Standards for Electricity Meters – 0.2 and 0.5 Accuracy Classes).

The EPA is proposing use of Appendices A, B, D, F and G to 40 CFR part 75. These Appendices contain standards that have already been reviewed under the NTTAA. The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this action.

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

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its 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.

This proposed rule limits GHG emissions from modified and reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) and stationary combustion turbines by establishing national emission standards for CO_2. The EPA has determined that this proposed rule would not result in disproportionately high and adverse human health or environmental effects on minority, low-income, and indigenous populations because it does not affect the level of protection provided to human health or the environment. As previously stated, the EPA expects few modified or reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis.

9.6 References

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