U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON ENERGY AND COMMERCE

October 20, 2015

TO: Members, Subcommittee on Energy and Power

FROM: Committee Majority Staff

RE: Hearing entitled "EPA's CO2 Regulations for New and Existing Power Plants: Legal Perspectives"

I. INTRODUCTION

On Thursday, October, 22, 2015, at 2:00 p.m. in 2123 Rayburn House Office Building, the Subcommittee on Energy and Power will hold a hearing entitled "EPA's CO2 Regulations for New and Existing Power Plants: Legal Perspectives."

II. WITNESSES

- **Elbert Lin,** Solicitor General of West Virginia;
- **Allison D. Wood,** Partner, Hunton & Williams, LLP;
- **Raymond L. Gifford,** Partner, Wilkinson Barker Knauer LLP;
- **Richard L. Revesz,** Lawrence King Professor of Law, Dean Emeritus, Director, Institute for Policy Integrity, New York University School of Law; and
- **Emily Hammond,** Associate Dean for Public Engagement, Professor of Law, George Washington University School of Law.

III. BACKGROUND

On August 3, 2015, the Environmental Protection Agency (EPA) announced two final rules and a third proposed rule to regulate carbon dioxide (CO2) emissions from new and existing fossil fuel-fired power plants.[1] The rules are being promulgated pursuant the President's Climate Action Plan and a Presidential Memorandum, which directs the EPA to develop new regulations for power plants pursuant to section 111 of the Clean Air Act (CAA). The

[1] The final rules were transmitted to Congress on Sept. 11, 2015. *See* Sept. 15, 2015 Congressional Record – House, at H5978; Sept. 17, 2015 Congressional Record-Senate, S6807-S6808.

prepublication versions of the rules exceed 3,000 pages and have not yet been published in the Federal Register.[2]

Section 111 of the CAA authorizes the Administrator of EPA, under certain circumstances, to establish standards of performance under section 111(b) for new stationary sources,[3] and to issue guidelines under section 111(d) for existing stationary sources.[4] Such regulations are referred to by the agency as "New Source Performance Standards" and "Existing Source Performance Standards." The rules announced on August 3, 2015, are summarized briefly below:

Final Rule for New Plants ("111(b) Rule"): In its final rule for new fossil fuel-fired plants,[5] EPA establishes separate CO2 standards for natural gas-fired and coal-fired electric generating units. For new natural gas-fired power plants, the rule determines that the "best system of emissions reduction"[6] (BSER) is based on the performance of a natural gas combined cycle (NGCC) unit, and the agency sets a standard of 1,000 pounds of CO2 per megawatt-hour on a gross-output basis (lb CO2/Mw-gross).[7] For new coal-fired units, the rule determines that the BSER is based on the performance of a supercritical pulverized coal utility boiler

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[2] The rules are accompanied by hundreds of additional pages of documentation, including regulatory impact statements, technical supporting documents, legal memoranda, draft guidance, and other documents, and the total number of pages released by the agency on August 3, 2015, exceeds 4,400 pages.

[3] Section 111(b) applies to new, modified, and reconstructed facilities and authorizes the EPA Administrator to establish Federal standards of performance for certain stationary sources that the Administrator has determined "causes or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare," and to establish "standards of performance" for such sources. 42 U.S.C.§7411(b)(1)(B).

[4] Section 111(d) authorizes the EPA Administrator to prescribe guidelines establishing a procedure under which States submit to the Administrator a plan establishing standards of performance for certain existing sources and certain air pollutants. 42 U.S.C.§7411(d). Section 111(d) has been invoked rarely by the agency, and EPA has regulated pollutants under this section from only five source categories: phosphate fertilizer plants (1977)(fluorides), sulfuric acid plants (1977)(acid mist), Kraft pulp mills (1979)(total reduced sulfur), primary aluminum plants (1980)(fluorides), and municipal solid waste landfills (1996)(landfill gas). *See* 79 Fed. Reg. at 34844, n.43. EPA also has regulated sewage sludge incinerators under section 111(d) in conjunction with CAA section 129. *Id.* at 34845, n. 44.

[5] *See "Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units"* ("Final 111(b) Rule"), Prepublication Version signed Aug. 3, 2015 (768 pages); *see also* EPA Overview Fact Sheet; Regulatory Impact Analysis; Rulemaking Documents.

[6] *See* EPA Overview Fact Sheet. Under section 111, a "standard of performance" is defined as: "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the *best system of emission reduction* which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." *See* 42 U.S.C. §7411(a)(1) (emphasis added).

[7] *See e.g.*, Final 111(b) Rule at 13-14; *see also* EPA Overview Fact Sheet. Non-base load natural gas units must meet a clean fuels input-based standard. *See* EPA Overview Fact Sheet.

implementing partial carbon capture and storage (CCS) and sets a standard of 1,400 lb CO2/Mw-gross.[8]

There are currently no full-scale coal-fired power plants in commercial service in the United States that have installed and operated the CCS technologies necessary to comply with the rule. The only operating power plant unit using CCS cited by the agency is a Canadian government funded, small-scale 110 megawatt (MW) unit, retrofitted to an existing plant, for enhanced oil recovery in the province of Saskatchewan, Canada.[9] Concerns have been raised that a standard based on CCS would constitute a de facto ban on the construction of new coal-fired power plants in the United States, including the most state-of-the-art coal-fired units presently under construction in other nations.[10]

Final Rule for Existing Plants ("Clean Power Plan" or "111(d) Rule"): In its final rule for existing fossil fuel-fired plants,[11] EPA establishes mandatory CO2 emissions "goals" for each state's electricity sector, including "interim" goals beginning in 2022 (separated into three steps in 2022-2024, 2025-2027, and 2028-2029), and a "final" goal in 2030.[12] The mandatory goals are expressed in terms of statewide rate-based and mass-based CO2 emissions goals. *Id.* at pp. 1556-1560. The goals are calculated based on 2012 emissions data, and EPA has prepared "State Specific Fact Sheets" and a Table estimating the percentage reductions from 2012 CO2 emissions. *See also* Appendix 1. The rate-based and mass-based mandatory goals for each state are set forth in Appendix 2.

For existing fossil fuel-fired electric generating units, EPA has determined that three "building blocks" reflect the BSER, including 1) heat rate improvements at existing coal units; 2) shifting from coal-fired generation to generation from existing NGCC units; and 3) shifting from coal-fired generation to generation from renewables, primarily wind and solar.[13] EPA calculates

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[8] *See, e.g.*, Final 111(b) Rule at 13-14; *see also* EPA Overview Fact Sheet. EPA determines the standard for coal plants could be met by natural gas co-firing, but does not consider natural gas co-firing as BSER. Final 111(b) Rule at 281-285.

[9] The only commercial-scale CCS power plant project in the United States currently under construction is a 582 MW project in Kemper County, Mississippi, which has been subject to years of delay and cost overruns, and has not yet commenced operation. Other U.S. CCS power plant projects cited to in EPA's proposed rule included a 400 MW Texas Clean Energy Project (TCEP) project and a 300 MW Hydrogen Energy California Project (HECA) project (*see* 79 Fed. Reg. 1430, 1432, n. 4(Jan. 8, 2014)), but neither have begun construction and DOE suspended funding for the HECA project in July 2015.

[10] *See, e.g.* Committee Report for H.R. 3826, "Electricity Security and Affordability Act," Feb. 28, 2014 at pp. 3-6.

[11] *See* "*Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units"* ("Final 111(d) Rule"), Prepublication Version signed Aug. 3, 2015 (1560 pages). *See also* EPA Overview and Fact Sheets; Regulatory Impact Analysis; Rulemaking Documents; Technical and Legal Documents; Legal Memorandum for Proposed Rule; Clean Power Plan Toolbox for States. *See also* CRS Report entitled "EPA's Clean Power Plan: Highlights of the Final Rule."

[12] *See, e.g.* Final 111(d) Rule at 234.

[13] *See, e.g.* Final 111(d) Rule at 27, 422-459. EPA further determines that for coal units the second and third building blocks can be implemented through a set of actions that may range from purchasing a full or partial interest

state goals based on this BSER, and has developed separate emissions performance rates for coal and natural gas plants, including an interim emissions rate for existing coal units of 1,534 lbs CO2 per Net MWh and a final rate of 1,305 lbs CO2 per Net MWh, and an interim emissions rate for existing natural gas units of 832 lbs CO2 per Net MWh and the final rate is 771 lbs CO2 per Net MWh.[14]

Under the rule, states would be required to submit detailed plans to meet their mandatory CO2 goals. State plans must be either "rate-based" or "mass-based" and take an "emissions standards approach," or alternatively a "state measures approach."[15] States may submit individual or multi-state plans, and are encouraged to use emissions trading,[16] and develop plans that will make their affected units "trading ready."[17] The final rule includes detailed provisions relating to development and implementation of state plans, including provisions relating to state measures, Emission Rate Credits (ERCs), allowances, emissions trading, demonstrations, monitoring and verification requirements, and recordkeeping and reporting requirements.[18] The rule includes an optional "Clean Energy Incentive Program" pursuant to which states would award early action ERCs for eligible renewable energy or demand-side energy efficiency projects that generate megawatt hours or reduce energy demand during 2020 and 2021.[19] The rule also includes provisions restricting the construction of new natural gas plants as a compliance measure.[20]

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in existing NGCC or renewable energy assets, to purchasing credits or allowances depending on whether a state has chosen a rate-based or mass based standard, to reducing operation. *See, e.g., id.* at 27, 239-240.

[14] *Id.* at 1556; *see also* EPA Overview Fact Sheet.

[15] *See, e.g.* Final 111(d) Rule at 31-35. An emissions standard plan "includes source specific requirements ensuring all affected power plants within the state meet their required emissions performance rates or state-specific rate-based or mass-based goal." *See* EPA Overview Fact Sheet. A state measures plan "includes a mixture of measures implemented by the state, such as renewable energy standards and programs to improve residential efficiency that are not included as federally enforceable components of the plan." *Id.* A "state measures plan" must also include a "federal backstop." *Id.* "States may use the final model [trading] rule, which EPA proposed August 3, for their backstop." *Id.*

[16] EPA states: "One cost-effective way that states can meet their goals is emissions trading, through which affected power plants may meet their emission standards via emission rate credits (for a rate-based standard) or allowances (for a mass-based standard)." *See* EPA Overview Fact Sheet.

[17] "In addition to including mass-based state goals to clear the path for mass-based trading plans, the final rule gives states the opportunity to design state rate-based or mass-based plans that will make their units "trading ready." *See* EPA Overview Fact Sheet. "EPA is committed to supporting states in the tracking of emissions, as well as tracking allowances and credits, to help implement multi-state trading or other approaches." *Id.*

[18] Final 111(d) Rule at 1456-1542.

[19] *Id.* at 1453-1455; *see also* EPA Fact Sheet.

[20] Final 111(d) Rule at 837-839, 1175-1186.

Under the rule, states must submit plans by September 6, 2016, with the possibility of a two year extension to be granted at the discretion of the agency.[21] In the event that a state fails to submit a satisfactory plan, the EPA would impose a yet to be finalized "Federal Plan."[22]

Accompanying the final 111(d) rule is a proposed rule setting forth two approaches to the "Federal Plan" that EPA would implement in any state that does not submit an approvable state plan.[23] For this "Federal Plan," the agency proposes both a rate-based trading program and a mass-based trading program, but intends to finalize only a single approach.[24] These proposals also constitute proposed "Model Trading Rules" that would be "presumptively approvable" for inclusion in state plans.[25] The proposed rule also includes revisions to the agency's current regulations for implementing section 111(d), including provisions relating to the disapproval of state plans.[26]

In the Regulatory Impact Analysis (RIA) accompanying the final 111(d) rule, EPA estimates costs to range from $1.4 billion to $2.5 billion in 2020, $1.0 billion to $3.0 billion in 2025, and $5.1billion to $8.4 billion in 2030 (RIA, Table 3-8 at p. 3-22). In developing these estimates, EPA assumes investments in demand side energy efficiency of $2.1 billion to $2.6 billion in 2020, $16.7 billion to $20.6 billion in 2025 and $26.3 billion to $32.5 billion in 2030 (RIA Tables 3-3 at p. 3-15). These additional costs are offset by projected reductions in electricity demand of up to 7.8 percent by 2030, according to the agency. (RIA, Table 3-2 at p. 3-14). According to EPA's estimates, natural gas use in the power sector may decline by as much as 4.5 percent over the base case in 2030, and coal production for the electric power sector declines by as much as 17 percent by 2025. (RIA, Tables 3-15 and 3-16 at pp. 3-33 to 3-34).

IV. ISSUES

[21] *Id.* at 1475. To request an extension, a state must submit an "initial plan" and address in its submittal: "1) An identification of final plan approach or approaches under consideration and description of progress made to date on the final plan components; (2) An appropriate explanation of why the State requires additional time to submit a final plan by September 6, 2018; and (3) Demonstration or description of opportunity for public comment on the initial submittal and meaningful engagement with stakeholders, including vulnerable communities, during the time in preparation of the initial submittal and the plans for engagement during development of the final plan." *Id.* at 1475-1476.

[22] *Id.* at 1451.

[23] *See* "*Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations,"* ("Proposed Federal Plan") Prepublication Version signed Aug. 3, 2015 (755 pages); *see also* related EPA Fact Sheet; *see also* Draft Guidance entitled "*Evaluation Measurement and Verification (EM&V) Guidance for Demand-Side Energy Efficiency (EE),*" August 3, 2015 (72 pages).

[24] *See* EPA Fact Sheet. While EPA has proposed both trading plans for public comment, the agency plans to select only one of those plans as the emissions trading plan to be implemented in all states subject to Federal Plans. *Id.*

[25] *See* EPA Fact Sheet. EPA intends to finalize both the rate-based and mass-based model trading rules in summer 2016. *Id.*

[26] *See* Proposed Federal Plan at 30, 345-369.

The following issues relating to EPA's regulations may be examined at the hearing:

- Legal issues raised by the regulations;
- Implementation and compliance issues;
- Potential impacts on states, local governments, and affected entities;
- Potential impacts on electricity rates and reliability; and
- Potential impacts on electricity markets.

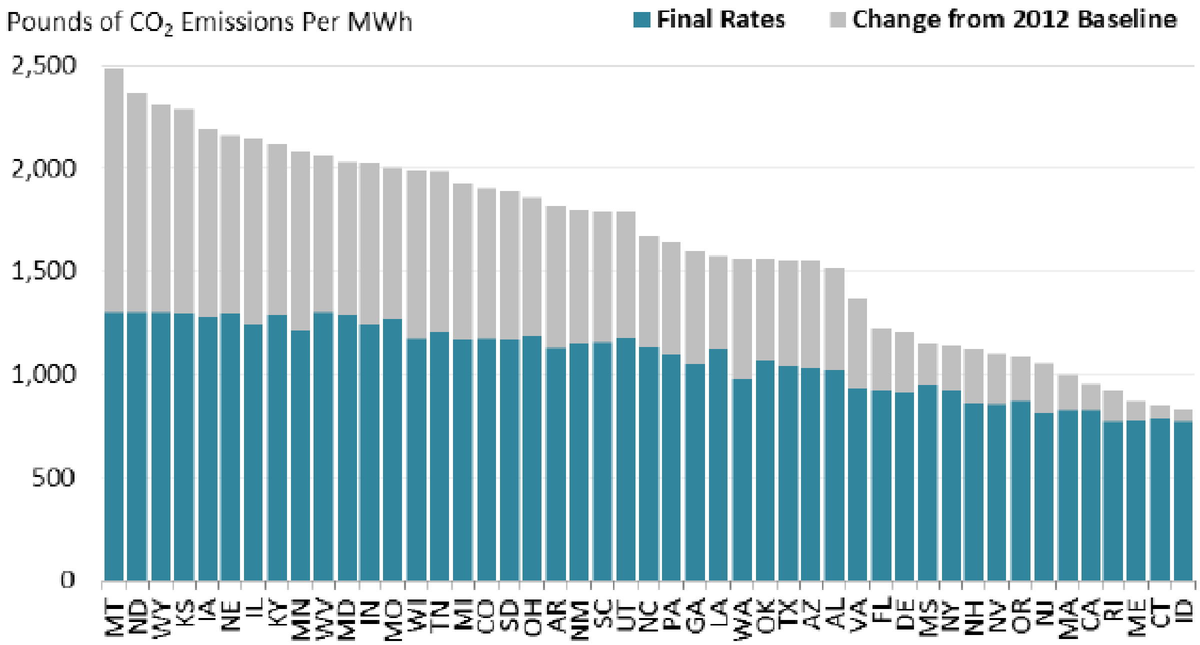
V. STAFF CONTACTS

If you have any questions regarding this hearing, please contact Mary Neumayr or Tom Hassenboehler of the Committee staff at (202) 225-2927.

Appendix 1

Figure 1. State-Specific Emission Rate Targets in 2030 Compared to 2012 Emission Rate Baselines

States Listed in Order of Their 2012 Emission Rate Baselines (High to Low)



Source: Prepared by CRS; final rule target and baseline data from EPA, CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule (August 2015) and accompanying spreadsheets, http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents.

Notes: The dark-colored columns illustrate the state-specific emission rate targets in 2030. The combined dark- and light-colored columns illustrate the state-specific emission rate baselines in 2012. The light-colored columns illustrate the emission rate reduction requirements states must achieve by 2030.

EPA did not establish emission rate goals for Vermont and the District of Columbia because they do not currently have affected EGUs. Although Alaska and Hawaii have targets in the proposed rule, in its final rule, EPA stated that Alaska, Hawaii, and the two U.S. territories with affected EGUs (Guam and Puerto Rico) will not be required to submit state plans on the schedule required by the final rule, because EPA "does not possess all of the information or analytical tools needed to quantify" the best system of emission reduction for these areas. EPA stated it will "determine how to address the requirements of section 111(d) with respect to these jurisdictions at a later time."

Source: CRS Report, p. 4, available at http://www.crs.gov/reports/pdf/R441

Appendix 2

Table 1 to Subpart UUUU of Part 60—CO_2 Emission Performance Rates

(Pounds of CO_2 per Net MWh)

Affected EGU	Interim Rate	Final Rate
Steam generating unit or integrated gasification combined cycle (IGCC)	1,534	1,305
Stationary combustion turbine	832	771

Table 2 to Subpart UUUU of Part 60—Statewide Rate-based CO_2 Emission Goals (Pounds of CO_2 per Net MWh)

State	Interim Emission Goal	Final Emission Goal
Alabama	1,157	1,018
Arizona	1,173	1,031
Arkansas	1,304	1,130
California	907	828
Colorado	1,362	1,174
Connecticut	852	786
Delaware	1,023	916
Florida	1,026	919
Georgia	1,198	1,049
Idaho	832	771
Illinois	1,456	1,245
Indiana	1,451	1,242
Iowa	1,505	1,283
Kansas	1,519	1,293
Kentucky	1,509	1,286
Lands of the Fort Mojave Tribe	832	771
Lands of the Navajo Nation	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,534	1,305
Louisiana	1,293	1,121
Maine	842	779

Maryland	1,510	1,287
Massachusetts	902	824
Michigan	1,355	1,169
Minnesota	1,414	1,213
Mississippi	1,061	945
Missouri	1,490	1,272
Montana	1,534	1,305
Nebraska	1,522	1,296
Nevada	942	855
New Hampshire	947	858
New Jersey	885	812
New Mexico	1,325	1,146
New York	1,025	918
North Carolina	1,311	1,136
North Dakota	1,534	1,305
Ohio	1,383	1,190
Oklahoma	1,223	1,068
Oregon	964	871
Pennsylvania	1,258	1,095
Rhode Island	832	771
South Carolina	1,338	1,156
South Dakota	1,352	1,167
Tennessee	1,411	1,211
Texas	1,188	1,042
Utah	1,368	1,179
Virginia	1,047	934
Washington	1,111	983
West Virginia	1,534	1,305
Wisconsin	1,364	1,176
Wyoming	1,526	1,299

Table 3 to Subpart UUUU of Part 60—Statewide Mass-based CO_2 Emission Goals (Short Tons of CO_2)

State	Interim Emission Goal (2022-2029)	Final Emission Goals (2 year blocks starting with 2030-2031)
Alabama	497,682,304	113,760,948
Arizona	264,495,976	60,341,500
Arkansas	269,466,064	60,645,264
California	408,216,600	96,820,240

Colorado	267,103,064	59,800,794
Connecticut	57,902,920	13,883,046
Delaware	40,502,952	9,423,650
Florida	903,877,832	210,189,408
Georgia	407,408,672	92,693,692
Idaho	12,401,136	2,985,712
Illinois	598,407,008	132,954,314
Indiana	684,936,520	152,227,670
Iowa	226,035,288	50,036,272
Kansas	198,874,664	43,981,652
Kentucky	570,502,416	126,252,242
Lands of the Fort Mojave Tribe	4,888,824	1,177,038
Lands of the Navajo Nation	196,462,344	43,401,174
Lands of the Uintah and Ouray Reservation	20,491,560	4,526,862
Louisiana	314,482,512	70,854,046
Maine	17,265,472	4,147,884
Maryland	129,675,168	28,695,256
Massachusetts	101,981,416	24,209,494
Michigan	424,457,200	95,088,128
Minnesota	203,468,736	45,356,736
Missouri	500,555,464	110,925,768
Mississippi	218,706,504	50,608,674
Montana	102,330,640	22,606,214
Nebraska	165,292,128	36,545,478
Nevada	114,752,736	27,047,168
New Hampshire	33,947,936	7,995,158
New Jersey	139,411,048	33,199,490
New Mexico	110,524,488	24,825,204
New York	268,762,632	62,514,858
North Carolina	455,888,200	102,532,468
North Dakota	189,062,568	41,766,464
Ohio	660,212,104	147,539,612
Oklahoma	356,882,656	80,976,398
Oregon	69,145,312	16,237,308
Pennsylvania	794,646,616	179,644,616
Rhode Island	29,259,080	7,044,450
South Carolina	231,756,984	51,997,936
South Dakota	31,591,600	7,078,962
Tennessee	254,278,880	56,696,792
Texas	1,664,726,728	379,177,684

Utah	212,531,040	47,556,386
Virginia	236,640,576	54,866,222
Washington	93,437,656	21,478,344
West Virginia	464,664,712	102,650,684
Wisconsin	250,066,848	55,973,976
Wyoming	286,240,416	63,268,824

Table 4 to Subpart UUUU of Part 60— Statewide Mass-based CO_2 Goals plus New Source CO_2 Emission Complement (Short Tons of CO_2)

State	Interim Emission Goal (2022-2029)	Final Emission Goals (2 year blocks starting with 2030-2031)
Alabama	504,534,496	115,272,348
Arizona	275,895,952	64,760,392
Arkansas	272,756,576	61,371,058
California	430,988,824	105,647,270
Colorado	277,022,392	63,645,748
Connecticut	58,986,192	14,121,986
Delaware	41,133,688	9,562,772
Florida	917,904,040	213,283,190
Georgia	412,826,944	93,888,808
Idaho	13,155,256	3,278,026
Illinois	604,953,792	134,398,348
Indiana	692,451,256	153,885,208
Iowa	228,426,760	50,563,762
Kansas	200,960,120	44,441,644
Kentucky	576,522,048	127,580,002
Lands of the Fort Mojave Tribe	5,186,112	1,292,276
Lands of the Navajo Nation	202,938,832	45,911,608
Lands of the Uintah and Ouray Reservation	21,167,080	4,788,708
Louisiana	318,356,976	71,708,642
Maine	17,592,128	4,219,936
Maryland	131,042,600	28,996,872
Massachusetts	103,782,424	24,606,744
Michigan	429,446,408	96,188,604
Minnesota	205,761,008	45,862,346

Mississippi	221,990,024	51,332,926
Missouri	505,904,560	112,105,626
Montana	105,704,024	23,913,816
Nebraska	167,021,320	36,926,888
Nevada	120,916,064	29,436,214
New Hampshire	34,519,280	8,121,182
New Jersey	141,919,248	33,752,728
New Mexico	114,741,592	26,459,850
New York	272,940,440	63,436,364
North Carolina	461,424,928	103,753,712
North Dakota	191,025,152	42,199,354
Ohio	667,812,080	149,215,950
Oklahoma	361,531,056	82,001,704
Oregon	72,774,608	17,644,106
Pennsylvania	804,705,296	181,863,274
Rhode Island	29,819,360	7,168,032
South Carolina	234,516,064	52,606,510
South Dakota	31,963,696	7,161,036
Tennessee	257,149,584	57,329,988
Texas	1,707,356,792	396,210,498
Utah	220,386,616	50,601,386
Virginia	240,240,880	55,660,348
Washington	97,691,736	23,127,324
West Virginia	469,488,232	103,714,614
Wisconsin	252,985,576	56,617,764
Wyoming	295,724,848	66,945,204

Source: Environmental Protection Agency. Final Rule entitled: "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," available at: http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf at pp. 1556-1560.