DATE: September 21, 2021

SUBJECT: Supplemental Data and Analysis for the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units – Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding; Notice of Proposed Rulemaking

TO: Docket ID No. EPA-HQ-OAR-2018-0794

This technical support document (TSD) presents detailed data and analysis to support the discussion in section III.B of the preamble for the proposed rulemaking for the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units – Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding. In section III.B ("Consideration of Cost of Regulating EGUs for HAP") of the preamble for the proposed rulemaking, the EPA examines the costs or disadvantages of regulation, including both the costs of compliance (which we explain we significantly overestimated in 2011) and how those costs affect the industry and the public.

Section III.B.2 of the preamble for the proposed rulemaking ("Compliance Cost Projections in the 2011 RIA Were Likely Significantly Overestimated") includes an examination of recent changes in natural gas supply, which is supported by section 1.a below. Section III.B.2 of the preamble also includes an analysis of the differences between projected and installed pollution controls, and the implications that those differences might have on the control costs projected in the 2011 RIA, which is supported by the data and analysis included in section 1.b below.

Section III.B.3 of the preamble ("Evaluation of Metrics Related to MATS Compliance") places the costs that we estimated in 2011 in the context of the EGU industry and the services the EGU industry provides to society. This section of the preamble includes a discussion of compliance costs as a percent of power sector sales, compliance expenditures compared to the power sector's annual expenditures, and retail prices, which are supported by the data and analysis presented below in sections 2.a, 2.b, and 2.c, respectively.

As discussed in the preamble of the proposed rule, in evaluating the costs and disadvantages of MATS, we begin with the costs to the power industry of complying with MATS. This assessment uses a sector-level (or system-level) accounting perspective to estimate the cost of MATS, looking beyond just pollution control costs for directly affected EGUs to include incremental costs associated with changes in fuel supply, construction of new capacity, and costs to non-MATS units that were also projected to adjust operating decisions as the power system adjusted to meet MATS requirements. Such an approach is warranted due to the nature of the power sector, which is a large, complex, and interconnected industry. This means that while the MATS requirements are directed at a subset of EGUs in the power sector, the compliance actions of the MATS-regulated EGUs can affect production costs and revenues of other units due to generation shifting and fuel and electricity price changes. Thus, the EPA's projected compliance cost estimate represents the incremental costs to the entire power sector to generate electricity, not just the compliance costs projected to be incurred by the coal- and oil-fired EGUs that are regulated under MATS. Limiting the cost estimate to only those expenditures incurred by EGUs directly regulated by MATS would provide an incomplete estimate of the costs of the rule.

Using this broad view, in the 2011 RIA we projected that the compliance cost of MATS would be $9.6 billion per year in 2015.[1] This estimate of compliance cost was based on the change in electric power generation costs between a base case without MATS and a policy case where the sector complies with the hazardous air pollutant (HAP) emissions limits in the final

[1] All costs were reported in 2007 dollars.

MATS. The EPA generated this cost estimate using the Integrated Planning Model (IPM).[2] This model is designed to reflect electricity markets as accurately as possible using the best available information from utilities, industry experts, natural gas and coal market experts, financial institutions, and government statistics. Notably, the model includes cost and performance estimates for state-of-the-art air pollution control technologies with respect to mercury and other HAP controls. But there are inherent limits to what can be predicted *ex ante*. And because the estimate was made 5 years prior to full compliance with MATS, stakeholders, including a leading power sector trade association, have indicated that our initial cost projection significantly overestimated actual costs expended by industry. There are significant challenges to producing an *ex post* cost estimate that provides an apples-to-apples comparison to our initial cost projections, due to the complex and interconnected nature of the industry. However, independent analyses provided to the EPA indicate that we may have overestimated the cost of MATS by billions of dollars per year. Moreover, there have been significant changes in the power sector in the time since MATS was promulgated that were not anticipated in either EPA or U.S. Energy Information Administration (EIA) projections at the time.[3] Entirely outside of the realm of EPA regulation, there were dramatic shifts in the cost of natural gas and renewables, state policies, and Federal tax incentives, which have also further encouraged construction of new renewables.

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[2] IPM, developed by ICF International, is a state-of-the-art, peer-reviewed, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. IPM provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies while meeting electricity demand and various environmental, transmission, dispatch, and reliability constraints. The EPA has used IPM for over two decades to understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emission impacts of prospective environmental policies.

[3] In 2009, coal-fired generation was by far the most important source of utility scale generation, providing more power than the next two sources (natural gas and nuclear) combined. By 2016, natural gas had passed coal-fired generation as the leading source of generation in the U.S. While natural gas-fired generation, nuclear generation and renewable generation have all increased since 2009, coal-fired generation has significantly declined.

These have led to significantly faster and greater than anticipated retirement of coal capacity and coal-fired generation.

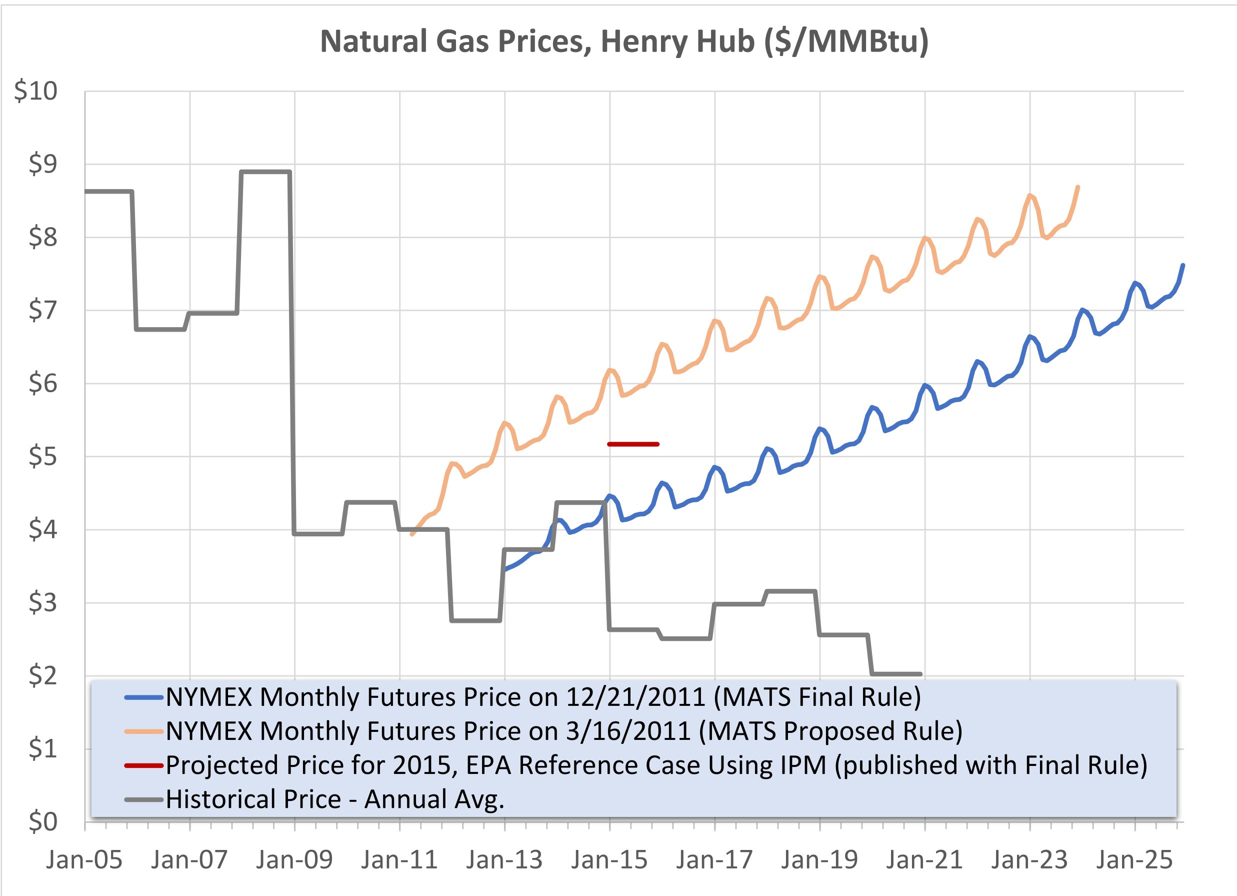
While there are significant limitations to producing an *ex post* cost estimate, we have endeavored, where possible, to approximate the extent of our overestimate. The unexpected shifts in the power sector, including the rapid increase in natural gas supplies that occurred after promulgation of MATS, resulted in our projected estimates of natural gas prices to be approximately double what they were in actuality. Incremental natural gas expenditures accounted for approximately 25 percent of the $9.6 billion compliance cost estimate for 2015 in the 2011 RIA. The market trends of the power sector also had major impacts on the number of controls installed and operated on coal-fired EGUs in the years following promulgation of MATS. With respect to just pollution control installation and operation, we project that we overestimated annual compliance costs by at least $2.2 to 4.4 billion per year, simply as a result of fewer pollution controls being installed than were estimated in the 2011 RIA. Though this range of an overestimate is limited to costs associated with pollution controls and operation, those costs made up 70 percent of the projected $9.6 billion figure.

1. **Technical Support for Preamble Section III.B.2 ("Compliance Cost Projections in the 2011 RIA Were Likely Significantly Overestimated")**

   a. **Natural Gas Supply (Supporting Preamble section III.B.2.a)**

Chart A-1 graphically depicts the natural gas prices presented in Table 2 of the preamble.

CHART A-1: NATURAL GAS PRICES



Source: Annual Average Henry Hub Price, EIA. NYMEX price, from S&P Global data. 2015 data from 2011 RIA, Chapter 3.

   b. **Projected versus Observed Control Installations (Supporting Preamble section III.B.2.b)**

In section III.B.2 of the preamble to the proposed rule, in order to retrospectively evaluate the projected costs in the 2011 RIA, the EPA compares the incremental projected pollution control capacity reported in the 2011 RIA with subsequently observed control installations. While subject to the caveats discussed in the preamble, this analysis demonstrates that the 2011 RIA likely significantly overestimated total pollution control retrofit capacity that would occur in response to MATS and, thus, likely significantly overestimated MATS compliance costs.

The preamble discussion is limited to those controls that are most directly related to reducing HAP emissions. While Table A-1 in this TSD includes all pollution controls that were included in the 2011 RIA, we note that observed installations of wet scrubber (wet flue gas desulfurization (FGD)) and selective catalytic reduction (SCR) systems were likely related to factors other than MATS. Electric utility steam generating units (EGUs) can achieve the MATS acid gas emissions limits using dry scrubbers (dry FGD) or dry sorbent injection (DSI) at a lower cost than using wet FGD scrubbers. Additionally, note that the 2011 RIA projected a 2.9 gigawatt (GW) decrease in retrofit wet FGD capacity relative to the base, because the sulfur dioxide (SO_2) allowance price under the Cross-State Air Pollution Rule (CSAPR) (in the base case, absent MATS) provided an incentive for the additional SO_2 reductions achieved by a wet scrubber relative to a dry scrubber. SCR controls are primarily installed to reduce nitrogen oxide (NO_X) emissions and can help to reduce mercury emissions when paired with certain other controls and plant configurations. Given the high cost of SCR controls relative to mercury controls, it is likely that the observed SCR control installations were primarily intended to reduce NO_X emissions, and were thus driven by other federal or state regulatory requirements beyond

MATS. For these two types of pollution controls, the table below includes observed installations that were not projected in the 2011 RIA base case.

TABLE A-1. PROJECTED VS. OBSERVED CAPACITY (GW)

Pollution Control Retrofit	Base Case	MATS	Projected Incremental Controls	Observed Installations (2013-2016)	Difference: Observed Minus Projected (2013-2016)
Dry FGD	4.6	24.8	20.3	16.0	-4.3
DSI	8.6	52.5	43.9	15.8	-28.1
ACI	0	99.3	99.3	96.1	-3.2
FF	12.7	114.7	102	31.4	-70.6
Electrostatic Precipitator Upgrade	0	33.9	33.9	N/A	N/A
Scrubber Upgrade	0	63.1	63.1	N/A	N/A
Wet FGD	10.9	7.9	-2.9	2.0	4.9
SCR	13.7	14	0.3	4.5	4.2

Source: Projected Controls: 2011 RIA; Observed Installations: NEEDS v.5.16.
Note: Projected fabric filter (FF) installations include installations specifically related to particulate matter (PM) control, as well as installations included with dry scrubbers, DSI, and some activated carbon injection (ACI) retrofits in the modeling. Totals may not sum due to rounding.

c. Approximating the Difference in Control Costs (Supporting Preamble section III.B.2.b)

In this section, the EPA approximates the potential magnitude of the difference between compliance costs associated with pollution controls that were projected to be installed in the 2011 RIA, and the costs associated with pollution controls that were actually installed between 2013-2016. In this analysis, the EPA looks at each EGU subject to MATS that was included in the 2011 RIA modeling, reports the retrofit pollution control devices that were projected for that

EGU, compares those projections to observations of actual control installations that occurred over 2013-2016, and estimates the associated costs of those controls.

Like the analysis of capacity above, this cost approximation analysis relies upon data regarding the observed online date of installed controls.[4] While assuming that these types of pollution controls that were installed before 2017 are singularly attributable to MATS requirements is a reasonable assumption for this analysis, it is likely that some of the observed installations occurred in response to other regulatory requirements (*e.g.*, CSAPR, Regional Haze Federal implementation plans or state implementation plans) or enforcement actions (*e.g.*, consent decrees). The observed installations summarized in this analysis therefore likely capture more regulatory drivers than MATS alone, meaning this analysis likely overestimates the amount of pollution controls built specifically for MATS compliance and therefore underestimates the extent to which the 2011 RIA overestimated costs related to these controls.

Unlike the capacity analysis, which evaluates aggregate levels of control capacity, the generating unit-specific nature of control costs requires this analysis be conducted at the EGU level, based on unit-level estimates. The modeling results presented in the 2011 RIA are based on direct model outputs of aggregate "model" plant projections (*i.e*., aggregates of generating units with similar operating characteristics). The unit-level estimates reported in this TSD are an

[4] The inventory of installed pollution controls and associated online dates is based on NEEDSv5.16 (available at: *https://www.epa.gov/airmarkets/power-sector-modeling-platform-v516*). This version of the NEEDS database reflects pollution control devices that were constructed or planned by the end of 2016 and is therefore a good representation of all controls that were installed over the MATS compliance period. Since there is some uncertainty associated with these online dates, and since the 2011 RIA modeling already captures controls that were installed before MATS, we compare projected installations to all of the control installations included in this database (excluding planned controls with an online year of 2017 or later). However, when identifying control installations that were not projected, we limit our analysis to those controls with online dates of 2013-2016 that were not included in the 2011 RIA base case. Since online years are not included in this database for FF, we assumed that all FF capacity included in NEEDS v5.16 (published December 2016), but not included in NEEDS v4.10 MATS (which informed the 2011 RIA modeling), was installed within the relevant MATS compliance timeframe for this analysis, which may overstate the attribution of observed FF installations to MATS compliance for such retrofits that were brought online after 2016.

approximation of model outputs at the generating-unit level. Another important difference is that the unit-level cost analysis focuses solely on the additional controls that were projected to be built under MATS incremental to the base case. However, the total compliance cost and pollution control capacities reported in the 2011 RIA (and in Table A-1 above), present a net perspective, accounting for these additional controls, as well as the controls that were projected to be built in the base case, but not projected to be built under MATS (in other words, a decrease in controls at the unit-level).

Table A-2 summarizes the results of the unit-level cost approximation analysis. The cost estimates in Table A-2 discussed in this section are for the modeled year of compliance in the RIA, or 2015, and denominated in 2007 dollars. This table presents four different groupings of retrofit pollution controls. The first group (group A in Table A-2) includes the sum of the unit-level estimates of the total projected incremental retrofit pollution control capacity and annual incremental control costs that are embedded in the 2011 RIA compliance costs projection. The pollution control retrofits for these units contribute costs of about $7.0 billion, which includes annualized capital, fixed operation and maintenance (O&M), and variable O&M costs. The annualized capital and O&M components of the cost are presented in Table A-3.

TABLE A-2. UNIT-LEVEL RETROFIT CONTROL ESTIMATES (ANNUAL COSTS, BILLIONS 2007$, AND CAPACITY, GW)

	(A) Total Incremental RIA Projections		(B) Projected and Installed by 2016		(C) Projected, Not Installed by 2016		(D) Not Projected, Installed (2013-2016)	
	$B	GW	$B	GW	$B	GW	$B	GW
Dry FGD	1.4	20.5	0.1	3.2	1.3	17.3	>0	12.9
DSI	2.0	47.1	0.2	4.3	1.8	42.9	>0	10.6
ACI	1.9	102.7	1.3	73.8	0.5	28.9	>0	22.1
FF	0.7	37.5	0.0	3.0	0.6	34.5	>0	11.9
ESP Upgrade	0.2	32.5	N/A	N/A	N/A	N/A	N/A	N/A
Scrubber Upgrade	0.7	64.2	N/A	N/A	0.0	3.2	N/A	N/A
Wet FGD	0.0	0.5	0.0	0.0	0.0	0.5	>0	2.0
SCR	0.1	2.8	0.0	0.0	0.1	2.8	>0	4.5
TOTAL	7.0	307.8	1.7	84.3	4.4	130.0	>0	63.9

Note: ">0" indicates that there is positive cost associated with these controls but EPA cannot quantify that cost at this time, as explained in section 1.b.; 2013-2016 data is not available for upgrades to existing ESPs and scrubbers (non-zero estimates reflect retirements); In this table, projected FF costs reflect only those FF that were included in the 2011 RIA modeling specifically for PM control. Other controls, like Dry FGD, DSI, and some ACI, include the cost of a new FF, and the costs of those FFs are included in the costs for their associated control.

TABLE A-3. UNIT-LEVEL RETROFIT CONTROL ESTIMATES (ANNUAL COSTS, BILLIONS 2007$)

	(A) Total Incremental RIA Projections			(B) Projected and Installed by 2016			(C) Projected, Not Installed by 2016		
	CAP	FOM + VOM	Total	CAP	FOM + VOM	Total	CAP	FOM + VOM	Total
Dry FGD	1.1	0.3	1.4	0.1	0.0	0.1	1.0	0.3	1.3
DSI	0.8	1.2	2.0	0.1	0.1	0.2	0.7	1.1	1.8
ACI	0.6	1.2	1.9	0.4	0.9	1.3	0.2	0.3	0.5
FF	0.6	0.0	0.7	0.0	0.0	0.0	0.6	0.0	0.6
ESP Upgrade	0.2	0.0	0.2	N/A	N/A	N/A	N/A	N/A	N/A
Scrubber Upgrade	0.7	0.0	0.7	N/A	N/A	N/A	0.0	0.0	0.0
Wet FGD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCR	0.1	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.1
TOTAL	4.2	2.8	7.0	0.7	1.0	1.7	2.7	1.8	4.4

To evaluate whether those costs might have been overestimated, we compare the unit-level estimates of projected incremental controls to the actual control installations observed on each unit by the end of 2016. Group B in Table A-2 includes pollution controls at those units that were projected to install these controls and were actually built at those units by 2016. This group includes 84.3 GW of capacity that, using the cost analysis from the 2011 RIA, represents about $1.7 billion of the $9.6 billion in compliance costs reported in the 2011 RIA. Group C in Table A-2 includes the incremental pollution controls that were projected in the 2011 RIA but were not observed to be installed by 2016. This bin includes 130 GW of capacity that represents about $4.4 billion of the $9.6 billion in compliance costs reported in the 2011 RIA. The costs associated with group C represent an approximation of a potential overestimate of the projected costs of pollution control installations in response to MATS.

Group D in Table A-2 includes controls that were observed to be installed over 2013-2016 but were not projected to be installed in the 2011 RIA and thus not included in the projected compliance cost estimate in the 2011 RIA. If we assume that all controls included in group D were built for MATS compliance, the cost associated with the controls in this group would represent a potential underestimate of the projected cost of pollution control installations in response to MATS. However, as we note above, it is highly unlikely that all of the group D controls were installed for MATS compliance, given other regulatory requirements that incentivize some of these pollution control retrofits within the 2013-2016 period.

While we are able to report the estimated unit-level costs associated with the controls projected to be installed in the 2011 RIA, we are unable to develop cost estimates that are consistent with the 2011 RIA for controls installed over the 2013-2016 period on units where that installation was not projected. To develop cost estimates that are comparable with the 2011 RIA based numbers presented elsewhere in Table A-2, we would need to apply model cost assumptions to capacity and generation levels that are consistent with the 2011 RIA model projections. Since these units were projected to operate in the 2011 RIA without the specified controls, we do not have generation estimates to apply to the cost assumptions.

However, we are able to observe that the total capacity of these installed controls in group D (that were not projected in the 2011 RIA) is less than the capacity of controls in group C that were projected but not installed. We can also observe that the installed capacity for each of the dry FGD, DSI, and ACI controls in group D is less than the projected capacity of these controls in group C. This is particularly true for DSI, where the capacity in group D is over 30 GW less than the capacity in group C. Therefore, the total cost of the controls in group D is likely less than $4.4 billion (the total projected cost of the controls in group C).

While we cannot approximate the costs of the controls that were installed but not projected in a manner that is directly comparable with the cost estimates of Groups A, B, and C, we can use average costs to calculate an illustrative estimate of the controls in group D in order to provide a point of comparison between group D and groups A, B, and C. Summing the product of the capacity of each control in Group D by the ratio of total costs to capacity in group A yields an estimate of $2.2 billion.[5] This approximation represents a rough estimate of the potential costs associated with controls that were installed but not included in the 2011 RIA compliance cost projections.

We can use the above information to develop a range of the potential overestimate of compliance costs related to control installations. We estimate the cost of controls in group D to be about $2.2 billion, while the controls in group C are estimated to cost $4.4 billion. The low end of the range of the control cost overestimate is $2.2 billion, or the difference between the cost estimates for groups C and D, which reflects the conservative assumption that all group D controls were installed entirely for MATS compliance. The high end of the range of the control cost overestimate is $4.4 billion, which reflects the assumption that controls in D were installed primarily for purposes other than MATS. As result of this analysis, which reflects the uncertainty associated with attributing the installed controls in group D to MATS requirements, we find that the 2011 RIA overestimated control costs by about $2.2 to $4.4 billion. Since the control cost component of the regulatory cost was estimated at $7.0 billion in the 2011 RIA for 2015, the modeled year of compliance, it is clear the control cost estimates in the 2011 RIA were likely overestimated by a significant amount.

It is important to note that the analysis in this TSD focuses specifically on the difference between projected and installed controls and the costs associated with those controls as reflected

[5] Note that this conservatively includes about $300 million in annual costs related to Wet FGD and SCR controls, which, as discussed above, are pollution controls that were likely installed in response to regulations other than MATS.

in the 2011 RIA projected compliance cost estimates. Meanwhile, preamble section III.B.2.c examines some recent updates to assumptions regarding the cost and performance of the pollution control retrofits that were projected to be installed for MATS in the 2011 RIA finding. If the EPA had captured these updates in the modeling that supported the 2011 RIA, the projected compliance costs would have been even lower. Connecting this finding to the quantitative assessment, it is possible that the 2011 RIA may overestimate costs related to pollution control by more than the high-end of the range (or $4.4 billion) presented here for 2015, the modeled year of compliance.

2. Technical Support for the Evaluation of Metrics Related to MATS Compliance (Supporting Preamble section III.B.3 ("Evaluation of Metrics Related to MATS Compliance")

a. Compliance Costs as a Percent of Power Sector Sales (Supporting III.B.3.a)

Table A-4 presents the value of retail electricity sales from 2000 to 2019, based on information from the U.S. Energy Information Administration (EIA), which provides technical support to section III.B.3.a of the preamble. To provide additional context, Table A-4 also presents the net generation totals for the electric power sector for the same period, also using information from the EIA.

TABLE A-4. REVENUES FROM RETAIL SALES AND NET ELECTRICITY GENERATION FOR THE ELECTRIC POWER SECTOR 2000 TO 2019

Year	Revenues from Retail Sales (billions of 2007 dollars)	Electricity Net Generation Total, Electric Power Sector (terawatthours)
2000	276.2	3,638
2001	286.7	3,580
2002	284.6	3,698
2003	291.0	3,721
2004	294.7	3,808
2005	315.3	3,902
2006	335.3	3,908
2007	343.7	4,005
2008	356.6	3,974
2009	343.9	3,810
2010	355.0	3,972
2011	349.7	3,948
2012	336.4	3,890
2013	340.9	3,904
2014	350.8	3,937
2015	345.9	3,919
2016	338.1	3,918
2017	335.2	3,877
2018	340.9	4,018
2019	331.0	3,966

Source: Electricity Sales from U.S. EIA, Form-826 Detailed Data, *http://www.eia.gov/electricity/data/eia826/,* accessed 6/5/2021. Net generation from U.S. EIA Annual Energy Review: *https://www.eia.gov/totalenergy/data/annual/,* accessed 7/3/2021.

Note: dollar figures adjusted to 2007 dollars using the Gross Domestic Product - Implicit Price Deflator, *https://research.stlouisfed.org/fred2/series/GDPDEF,* accessed 6/05/21.

The data show that net generation totals from the electric power sector rose from 3,638 terawatt-hours (tWh) in 2000 to just over 4,005 tWh in 2007. After 2007, net generation totals remained relatively flat, hovering between a low of 3,810 tWh in 2009 and a peak of 4,018 tWh in 2018, observing a post-2011 low of 3,877 tWh in 2017.

Revenues from retail electricity sales increased from $276.2 billion in 2000 to a peak of $356.6 billion in 2008 (an increase of about 29 percent during this period) and have slowly declined since to a post-2011 low of $331.0 billion in 2019 (a decrease of about 7 percent from its peak during this period). The relatively small declines in retail electricity sales since their peak levels in 2009 is in large part explained by the relatively flat levels of net generation since then in combination with inflation-adjusted retail prices generally declining since 2008 (*see* section III.B.7 for details on retail electricity price trends for this period).

b. Compliance Expenditures Compared to the Power Sector's Annual Expenditures (Supporting III.B.3.b)

Table A-5 presents two sets of estimates for trends in annual capital expenditures by the electric power sector, which provides technical support to section III.B.3.b of the preamble. For power sector-level capital expenditures, the EPA relies on two sets of information. The first set of information is from information compiled by S&P Global, a private sector firm that provides data and analytical services. The second set of information is from the U.S. Census Bureau's Annual Capital Expenditures Survey. While each dataset has limitations, the estimates from each correspond to one another reasonably well. The annual sector-level capital expenditures reported by S&P Global are generally lower than the information from the Census Bureau. This is, in part, because S&P Global captures information on capital expenditures from Securities and Exchange Commission (SEC) filings, which are submitted by most but not by all entities in the power sector, whereas the U.S. Census Bureau's estimate of capital expenditures in the power sector is intended to capture capital expenditures for all entities in the power sector. For this reason, we present both sets of information to better depict capital expenditures in the power sector.

Capital expenditures generally increased from 2000 to 2019, but not in a linear fashion. In 2000, capital expenditures for the electric power sector are estimated to have been $51.7 billion and $62.3 billion based on S&P Global and U.S. Census Bureau data, respectively. Capital expenditures for this sector reached a low in 2004 at $40.3 billion and $44.9 billion, respectively, rising to their peak in 2019 at $115.6 billion and $113.0 billion, respectively, according to the S&P Global data and U.S. Census Bureau data.

TABLE A-5. TOTAL CAPITAL EXPENDITURES FOR THE ELECTRIC POWER, GENERATION, TRANSMISSION, AND DISTRIBUTION SECTOR (BILLIONS OF 2007 DOLLARS), 2000 TO 2019

	Capital Expenditures Collected by S&P Global from SEC Filings[1]		Capital Expenditures Based on U.S. Census Bureau Annual Capital Expenditures Survey[2]	
	Capital Expenditures	Change from Previous Year	Capital Expenditures	Change from Previous Year
2000	51.7	---	62.3	---
2001	69.9	18.2	85.7	23.4
2002	56.2	-13.6	66.2	-19.5
2003	43.7	-12.5	52.6	-13.6
2004	40.3	-3.4	44.9	-7.6
2005	46.6	6.3	50.0	5.0
2006	57.5	10.9	61.6	11.7
2007	66.9	9.3	73.9	12.3
2008	78.0	11.2	83.5	9.6
2009	76.6	-1.4	87.9	4.4
2010	75.1	-1.5	79.8	-8.1
2011	79.6	4.4	79.2	-0.6
2012	95.0	15.5	95.8	16.5
2013	94.9	-0.1	82.1	-13.6
2014	97.3	2.4	86.4	4.2
2015	103.9	6.6	94.3	7.9
2016	109.0	5.1	95.6	1.3
2017	108.9	-0.1	93.5	-2.1
2018	114.9	6.0	97.3	3.8
2019	115.6	0.7	113.0	15.7

[1] Source: S&P Global, accessed July 19, 2021.

[2] Source: U.S. Census Bureau, Annual Capital Expenditures Survey, *https://www.census.gov/programs-surveys/aces.html*, accessed 6/5/2021.

Note: Dollar figures adjusted to 2007 dollars using the Gross Domestic Product - Implicit Price Deflator, *https://research.stlouisfed.org/fred2/series/GDPDEF*, accessed 6/5/2021. Changes may not sum due to independent rounding.

Table A-6 presents the total capital and production expenditures for the electric power sector from 2000 to 2019, which provides technical support to section III.B.3.b of the preamble. The production costs, which include O&M costs, fuel costs, and fixed costs were obtained from Hitachi Powergrids Velocity Suite (HPVS), a private sector firm that provides data and analytical services for the energy sector. These production costs are added to the two separate estimates of annual capital expenditures provided in the previous section in order to provide an estimate of historical trends in total capital and production costs faced by the power sector. Again, we present both sets of information regarding capital costs to better depict total expenditures in the power sector.

The estimated $9.6 billion total annual cost of the rule represents the total incremental annual capital and production costs to the sector for 2015. This incremental cost due to MATS requirements represents a small fraction of the power sector's annual capital and production expenditures in recent years, as illustrated in Table A-5. For example, when compared to historical total expenditures that rely upon S&P Global-based estimates of capital expenditures and Hitachi Powergrids Velocity Suite estimates of production expenditures, the total 2015 MATS cost represents at its relative low about 4.3 percent of total expenditures in 2008 to its relative high of 6.6 percent of total expenditures in 2003. With respect to historical total expenditures that rely upon Census Bureau-based estimates of capital expenditures and Hitachi Powergrids Velocity Suite estimates of production expenditures, the total 2015 MATS cost represents at its relative low about 4.2 percent of total expenditures in 2008 to its relative high of 6.2 percent of total expenditures in both 2003 and 2004.

TABLE A-6. TOTAL CAPITAL AND PRODUCTION EXPENDITURES FOR THE ELECTRIC POWER SECTOR (BILLIONS OF 2007 DOLLARS), 2000 TO 2019

Year	Capital Expenditures (S&P)[1]	Capital Expenditures (Census)[2]	Total Production Expenditures (HPVS)[3]	Total Expenditures (S&P + HPVS)	Change from Previous Year	Total Expenditures (Census + HPVS)	Change from Previous Year
2000	51.7	62.3	101.1	152.7	---	163.4	---
2001	69.9	85.7	105.1	175.0	22.3	190.9	27.5
2002	56.2	66.2	91.9	148.1	-26.9	158.1	-32.8
2003	43.7	52.6	102.8	146.5	-1.7	155.3	-2.7
2004	40.3	44.9	110.5	150.8	4.3	155.4	0.1
2005	46.6	50.0	132.8	179.5	28.7	182.8	27.4
2006	57.5	61.6	126.8	184.3	4.9	188.4	5.6
2007	66.9	73.9	132.3	199.2	14.8	206.2	17.8
2008	78.0	83.5	146.3	224.4	25.2	229.8	23.6
2009	76.6	87.9	117.3	193.9	-30.5	205.2	-24.6
2010	75.1	79.8	126.0	201.1	7.2	205.8	0.6
2011	79.6	79.2	121.0	200.5	-0.6	200.2	-5.6
2012	95.0	95.8	110.0	205.0	4.5	205.8	5.6
2013	94.9	82.1	111.9	206.8	1.7	194.0	-11.8
2014	97.3	86.4	118.2	215.4	8.7	204.6	10.6
2015	103.9	94.3	100.9	204.8	-10.7	195.2	-9.4
2016	109.0	95.6	92.8	201.8	-3.0	188.4	-6.8
2017	108.9	93.5	91.3	200.2	-1.6	184.8	-3.6
2018	114.9	97.3	93.2	208.1	7.9	190.4	5.7
2019	115.6	113.0	85.1	200.7	-7.4	198.1	7.6

[1] Source: S&P Global, accessed July 19, 2021.

[2] Source: U.S. Census Bureau, Annual Capital Expenditures Survey, *http://www.census.gov/econ/aces/index.html*, accessed 6/5/2021.

[3] Source: Hitachi Powergrids Velocity Suite (HPVS) "Total Production Costs" dataset. This dataset compiles O&M costs, fuel costs, and fixed costs reported in the FERC Form 1, RUS 12, and EIA 412. For plants that do not report cost information, production costs are estimated by Hitachi Powergrids Velocity Suite. Note figures for 2000-2011 changed slightly from the results presented in the 2016 Supplemental Finding (81 FR 24420, April 25, 2016) due to revisions to the historical data.

Note: dollar figures adjusted to 2007 dollars using the Gross Domestic Product - Implicit Price Deflator, *https://research.stlouisfed.org/fred2/series/GDPDEF*, accessed 6/5/2021. Changes may not sum due to independent rounding.

c. Retail Prices (Supporting III.B.3.c)

Table A-7 presents trends in the average retail price of electricity for all sectors (residential, commercial, industrial, transportation, and other sectors) between 2000 and 2019 using data from the EIA, which provides technical support to section III.B.3.c of the preamble.

TABLE A-7. AVERAGE RETAIL PRICE OF ELECTRICITY, ALL SECTORS, 2000 TO 2019

Year	Average Electricity Retail Price (cents per kilowatt-hour in 2007 dollars)	Change from Previous Year (cents per kilowatt-hour in 2007 dollars)
2000	8.07	N/A
2001	8.45	0.38
2002	8.22	-0.23
2003	8.34	0.12
2004	8.30	-0.03
2005	8.61	0.31
2006	9.14	0.53
2007	9.13	-0.01
2008	9.55	0.42
2009	9.56	0.01
2010	9.46	-0.10
2011	9.33	-0.13
2012	9.10	-0.23
2013	9.15	0.05
2014	9.32	0.16
2015	9.20	-0.11
2016	8.98	-0.22
2017	9.00	0.01
2018	8.83	-0.17
2019	8.68	-0.15

Source: U.S EIA, Electricity Data Browser, *http://www.eia.gov/electricity/data/browser*, accessed 6/05/21.
Note: Dollar figures adjusted to 2007 dollars using the Gross Domestic Product - Implicit Price Deflator, *https://research.stlouisfed.org/fred2/series/GDPDEF*, accessed 6/5/2021. Changes may not sum due to independent rounding.