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Construction and Application of the Micro-level Engineering, Environmental, and Economic Detail of Electricity (MEEDE) Dataset, Version 2

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Abstract

ABSTRACT: The Micro-level Engineering, Economic, and Environmental Detail of Electricity (MEEDE, Version 2) dataset provides a unit-level representation of the United States electricity sector based on public sources. The data draw on a disparate set of engineering, environmental, and economic data, primarily from the Environmental Protection Agency and the Department of Energy's Energy Information Administration, to characterize all utility-scale electric generating units in the U.S. in terms of their physical inputs of energy, outputs of electricity and pollution, generating and pollution control equipment configurations, and economic costs (capital, labor, energy, and materials) associated with their operation. The combination of complete unit-level physical details of the US grid with economic characteristics is a key distinction between the MEEDE data and other publicly-available sources. The MEEDE data provide a highly-valuable tool for generating descriptive statistics and supporting advanced partial or general equilibrium modeling efforts that require technology-rich representations of the U.S. electricity grid. We demonstrate how these data can be integrated into social accounting matrices for use in economy-wide modeling applications.

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Disclaimer

The views expressed in this paper are those of the author(s) and do not necessarily represent those of the U.S. Environmental Protection Agency (EPA). In addition, although the research described in this paper may have been funded entirely or in part by the U.S EPA, it has not been subjected to the Agency's required peer and policy review. No official Agency endorsement should be inferred. Further, the contractor's role did not include establishing Agency policy.

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Contents

1 Introduction

This methods report explains the construction and application of the second version of a detailed dataset covering electricity generation in the United States based entirely on public sources: the Micro-level Engineering, Economic, and Environmental Detail of Electricity (MEEDE). These data provide a full economic and environmental profile of the physical equipment operating on the U.S. electric grid in annual time series from 2013 to 2019.[1] The detailed grid profile offered by the MEEDE data is ideal for integration into partial and general equilibrium economic models. Toward that end, this model documentation also provides a social accounting matrix sector disaggregation and matrix balancing routine along with recommendations for general equilibrium model specifications for the electricity sector.

MEEDE is made up of power plant- and boiler- level information from various publicly-available datasets provided by the Energy Information Administration (EIA), the Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC), and the National Renewable Energy Laboratory (NREL). This includes: (1) engineering data such as boiler-to-pollution control equipment configurations, boiler-level fuel consumption quantities, and generator electricity output; (2) economic data on power plant capital and operating costs, and emissions control equipment-related costs; and (3) environmental data on power plant emissions rates of various pollutants and greenhouse gases.

This version of MEEDE is the successor to the MEEDE dataset released in 2016 for the data year 2013 (MEEDE Version 1). Unlike the first version, which only covered the electricity sector landscape of 2013, Version 2 includes seven years of data, from 2013 to 2019. Several other improvements (detailed below) have been made in this update as well, including the use of continuously-monitored emissions data collected by the Environmental Protection Agency and the application of electricity sales information from the Federal Energy Regulatory Commission. As such, the outputs in MEEDE Version 2 do not correspond directly with those from MEEDE Version 1 including for the year 2013. This updated version provides a more complete snapshot of the U.S. electricity sector.

The combined physical and economic detail compiled in MEEDE is ideal for use in partial and general equilibrium economic models. Unit level information in MEEDE observations can be aggregated readily on a variety of plant characteristics such as fuel type, primve mover, pollution controls, or location to generate prototypical plants for modeling purposes. Such “bottom-up” aggregations pose unique challenges when used with economy-wide models, whose base data do not comport with bottom-up information. Combining multiple sources of economic data for use in general equilibrium models therefore requires a method to re-balance the aggregated sources for micro-consistency. We develop a numerical algorithm to re-balance our social accounting matrices with integrated bottom-up data.

This report is organized as follows. First, the Methods section presents the construction of the MEEDE dataset in three subsections by the type of data: engineering, economic, or environmental. Within each of these sections, we introduce the datasets by source and describe how the data is assembled as well as any assumptions we make regarding the data. At the end of each of the three sections, we provide a summary to describe the assembled data. In a fourth subsection, we discuss

[1] At the time of MEEDE Version 2’s release, the Energy Information Administration’s Forms 923 and 860 only published data up to 2019.

the full MEEDE dataset by presenting trends through time (from 2013 to 2019). We also discuss how this MEEDE update differs from the 2013 version.

Second, the Applications section describes the integration of the bottom-up information provided by the MEEDE dataset into a balanced social accounting matrix. We discuss the social accounting matrix identities, priors, disaggregation, and balancing routine. We conclude this section by presenting recommendations for general equilibrium model specifications for the electricity sector.

2 Methods

Data provided in national accounts present an aggregated electricity generation, transmission, and distribution sector. Capturing the heterogeneity of production and abatement alternatives requires a finer-grain representation, disaggregated along several dimensions to the level of generation abatement technology types. To achieve this, we integrate the EIA Forms 923 and 860 data (U.S. Energy Information Administration, 2021a,b), the NREL Annual Technology Baseline (ATB) generation cost estimates (National Renewable Energy Laboratory, 2021), the EPA Integrated Planning Model (IPM) abatement cost estimates (U.S. Environmental Protection Agency, 2018), and EPA emissions data to provide a comprehensive dataset covering 97 percent of electricity generation capacity in the U.S. (U.S. Energy Information Administration, 2021c).[2] This covers almost 100 percent of all U.S. power plant emissions and abatement activity, as the 3 percent comprising smaller-scale (i.e., not utility-scale) systems are primarily solar.

2.1 Engineering

2.1.1 Activity Data: Energy Information Administration Forms 923 and 860

Data Assembly

The MEEDE data rely most heavily on EIA Forms 923 and 860 for the years 2013 to 2019 (U.S. Energy Information Administration, 2021a,b). These forms collect information from electricity generating units (EGUs) primarily under the North American Industry Classification System (NAICS) code 22 for Utilities (approximately 83 percent of all units), but also include data from other other industries (U.S. Census Bureau, 2021; U.S. Energy Information Administration, 2021d).[3] Form 923 data record activity levels of EGUs, including fuel use and net generation quantities. The data also contain basic characteristics of each generating unit such as fuel type, prime mover, and location. The Form 923 data provide 38 fuel types, which we collapse to 15 fuel codes. We do not collapse the 18 unique prime movers.

Data from Form 923 page 1 summarize the total quantity of fuel input and electricity generation output by fuel code, prime mover, and plant. From these data we were able to summarize generation by fuel type, prime mover, and region. Table 1 presents the net electricity generation by each prime mover across the North American Electric Reliability Corporation (NERC) regions.

Form 923 page 3 provides boiler-level detail on the type and total quantity of fuel inputs. Pollution control equipment can be associated with the boiler(s) it serves using the Form 860 data. Identifying the emissions profile of generation then requires a reliable mapping between boilers and prime movers. This mapping is a many-to-many exercise: one boiler may serve multiple prime movers, or multiple boilers may serve one prime mover. Fortunately, page 3 of the Form 923 data breaks

[2]The 97 percent of generation capacity includes only grid connected, utility-scale electricity generators, which are defined as those located at power plants with at least 1 MW of total electricity generating capacity. This dataset does not cover smaller-scale systems such as distributed generators and rooftop solar panels, which make up the remaining approximately 3 percent of total capacity.

[3]Other industries include: Agriculture, Forestry, Fishing and Hunting (NAICS code 11; less than 1 percent of the 97 percent generator coverage); Mining (code 21; less than 1 percent); Manufacturing (codes 31-33; approximately 9 percent); Transportation and Warehousing (codes 48-49; less than 1 percent); and Administrative and Support and Waste Management and Remediation Services (code 56; less than 1 percent). The remaining 5 percent of units include those in the healthcare, real estate, and finance industries.

Table 1: Annual net electricity generation from EIA Form 923 by prime mover and NERC region, 2019 (in thousands of MWh)

		Annual Net Generation (Thousands of MWh)								
Code	**Description**	**SERC**	**RFC**	**WECC**	**MRO**	**TRE**	**NPCC**	**HICC**	**ASCC**	**Total USA**
ST	Steam Turbine	709,119	570,254	238,591	216,269	131,440	93,375	5,476	700	1,965,224
CT	Combined Cycle (Combustion)	357,439	164,107	127,261	43,135	118,727	46,809	1,879	1,554	860,912
CA	Combined Cycle (Steam)	172,856	83,753	69,181	25,003	55,176	22,802	583	457	429,811
HY	Hydraulic Turbine	44,683	10,532	167,310	24,196	1,072	38,320	95	1,623	287,830
WT	Wind (Onshore)	5,676	30,267	54,377	119,566	76,063	8,072	529	143	294,693
GT	Gas Turbine	46,607	26,521	24,515	14,301	17,264	5,954	536	404	136,102
PV	Photovoltaic	16,302	2,655	41,133	1,861	4,330	2,062	268	0	68,611
CS	Combined Cycle (Single)	2,036	28,056	6,311	603	8,656	13,145	0	0	58,808
BT	Binary Cycle Turbines	0	0	4,340	0	0	0	0	0	4,340
IC	Internal Combustion (Diesel)	2,448	4,018	3,539	1,638	1,521	1,265	384	1,191	16,005
FC	Fuel Cell	59	294	911	0	0	381	0	0	1,645
CP	Concentrated Solar (Storage)	0	0	842	0	0	0	0	0	842
PS	Pumped Storage	-2,776	-1,680	-211	156	0	-750	0	0	-5,261
WS	Wind (Offshore)	0	0	0	0	0	118	0	0	118
BA	Battery	0	-38	-30	-2	-11	-8	-1	-4	-94
FW	Energy Storage (Flywheel)	0	-14	0	0	0	-11	0	0	-26
CE	Compressed Air (Storage)	-7	0	0	0	0	0	0	0	-7
OT	Other	110	235	18	325	0	59	0	0	747
Total		**1,354,551**	**918,960**	**738,088**	**447,052**	**414,237**	**231,593**	**9,750**	**6,068**	**4,120,300**

Regions: ASCC = Alaska Systems Coordinating Council; HICC = Hawaiian Islands Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.
Note: The values shown here may not sum to the totals shown due to independent rounding.

out boiler inputs (BID) by plant ID (PID), the prime movers (PM) they serve, and fuel type (FT). Table 2 shows a meta-summary of the data available in Form 923. It includes the unit of observation and variables provided by Form 923 pages 1 and 3.

We can use the boiler-level fuel data from page 3 to allocate the generation data from page 1, giving fuel use and estimated generation output data at the PID-PM-FT-BID level. The second to last column of Table 2 reveals that roughly 16 percent of power plants in Form 923 are served by boilers (i.e., 1469 plants relative to 9809), but nearly half of all generation is provided through the use of boilers (see steam turbines in Table 1).

Pollution control processes and equipment are given control IDs that are associated with plant boilers, meaning environmental control equipment is associated only with steam generation in the Form 860 data (Table 2). Through this association we can assign environmental control processes

Table 2: Meta-summary of EIA Form 923 data, 2019

Form	Schedule	Page	Observation	Variables	Number of Plants	Number of Observations
923	2_3_4_5_M_12	Page 1: Generation and Fuel Data	{PID, PM, FT}	< Fuel, Generation >	9,809	14,345
923	2_3_4_5_M_12	Page 3: Boiler Fuel Data	{PID, PM, FT, BID}	< Fuel, Sulfur Content, Ash Content >	1,469	9,551
923	2_3_4_5_M_12	Page 5: Fuel Receipts and Costs	{PID}	< Monthly Fuel Prices >	1,006	38,107
860	3.1	Operable	{ PID, GID, PM, FT }	< Nameplate Capacity, Operating Year, Planned Retirement Year >	9,804	22,731
860	2	Plant	{ PID }	< Plant Attributes >	11,833	11,833
860	6.1	Boiler-Generator	{ PID, GID, BID }	< PID, GID, BID >	1,660	7,402
860	6.2	Boiler Info & Design Parameters	{ PID, BID }	< PID, BID, In-service Year, Firing Type, Wet/Dry Bottom Tech >	1,661	4,680
860	6.1	Boiler Particulate Matter	{ PID, BID, FGP_ID }	< PID, ID, FGP_ID >	835	2,423
860	6.1	Boiler SO2	{ PID, BID, FGD_ID }	< PID, BID, FGD_ID >	438	973
860	6.1	Boiler NOX	{ PID, BID, NOX_ID }	< PID, BID, NOX_ID >	790	1,742
860	6.1	Boiler Mercury	{ PID, BID, HG_ID }	< PID, BID, HG_ID >	491	1,455
860	6.1	Emissions Control Equipment	{ PID, FGP_ID, FGD_ID, NOX_ID, HG_ID, Equipment Type, Controls }	< Control ID (PM, SOX, NOX, HG), Equipment Type >	1,184	5,787
860	6.2	Emission Standards & Strategies	{ PID, BID }	< PID, BID, Control Strategies: SOX, NOX, HG >	1,661	4,680
860	6.1	Boiler Stack Flue	{ PID, BID, FID }	< PID, BID, FID >	901	3,009
860	6.2	Stack Flue	{ PID, FID }	< PID, FID, Service Year, Height, Volume, Status >	904	2,459

Abbreviations: BID = boiler ID; FGD_ID = flue gas desulfurization equipment ID; FGP_ID = flue gas particulate collector ID; FT = fuel type; GID = generator ID; HG_ID = mercury equipment ID; NOX_ID = nitrogen oxide equipment ID; PID = plant ID; PM = prime mover; SOX_ID = sulfur oxide equipment ID.

and equipment to the boilers represented in Form 923 page 3 boiler data. Then, with the boiler technology characterized, we can identify what fuel input and electricity outputs are traveling through which generation equipment and pollution control technology configurations.

We construct a plant-boiler-level dataset that identifies the type and age of environmental equipment for all available boilers on the grid using the environmental association and equipment datasets from Form 860 Schedule 6.1. The Emissions Control Equipment Page of Form 860 provides the plant ID, associated control IDs, and the control equipment type (e.g., dry sorbent injection for SO2 control), while the other pages in Schedule 6.1 provide the BID to control ID mapping. Environmental equipment controls include those for sulfur, nitrogen, mercury, and particulates. Given the importance of flue height for local health effects from pollution, we also generate the emissions-weighted average flue height of each boiler (some boilers are served by multiple flues). The Form 860 environmental association file provides the type of environmental equipment installed at each plant and the boilers the equipment serves. The environmental equipment file provides additional attributes for boilers (including boiler age) and some of the control equipment.

The Form 860 data also provide attributes at the generator and plant levels. Age and nameplate capacity by generator are key variables in estimating the cost of generation. Because the final dataset will be summarized at the PID-PM-FT-BID level, we sum nameplate capacity and took a nameplate-weighted average age of the generators at the PID-PM level. The plant file provides a variety of geographic and regulatory location characteristics that are merged with the generator and boiler data at the plant level. The final engineering dataset summarizes the generation and abatement technologies operating on the grid with plant-, generator-, and boiler-level detail. When applicable, we break generation out to the boiler level and identified associated environmental equipment. The unit of observation is the PID-PM-FT-BID tuple wherever the boiler is applicable and PID-PM-FT otherwise. Across all seven years (2013-2019), there are 91,296 distinct observations in total and 133 variables. In 2019 alone, there are 14,347 distinct observations. The variables provide detailed information on the geographic and regulatory location of the plants; the ages of combustion, generation, and abatement equipment; the physical and thermal quantities of fuel consumed; the flues and environmental equipment involved in the combustion of those quantities; the boiler cooling equipment associated with each boiler; and the water use of the cooling equipment.

Data Assumptions

The EIA Forms 923 and 860 datasets are our most comprehensive in terms of plant coverage and plant-level technological details. This is the dataset on which we map the economics and environment-related data. However, it reports only utility-scale electricity generators, which are defined as those located at power plants with at least 1 MW of total electricity generating capacity (U.S. Energy Information Administration, 2021c). Therefore, this dataset does not cover smaller-scale systems such as rooftop solar panels.

2.1.2 Engineering Data Description

Table 1 shows that steam turbines generated the majority of electricity in 2019 (1,965 million MWh of the U.S. total of 4,120 million MWh generation), followed by combined-cycle combustion prime movers (CT; 861 million MWh) and then combined-cycle steam prime movers (CA; 430 million MWh). In terms of regional variability in electricity generation, Table 1 shows that the Southeastern Electric Reliability Council (SERC) region has the largest amount of generation nationally. It also dominates in generation by steam turbine, combined cycle, gas turbine prime movers. The NERC region with the second largest annual net generation is the ReliabilityFirst Corporation (RFC) region, which covers the Mid-Atlantic and parts of the Midwest. The RFC region generates about 30 percent less electricity than SERC. The Western Electricity Coordinating Council (WECC) region follows next in terms of total annual net generation, but leads in generation by hydropower (roughly 58 percent of all hydropower generation) and solar (almost 60 percent of all solar generation). The Midwest Reliability Organization (MRO) region, which are the West North Central states, leads in terms of onshore wind generation, covering 40 percent of all wind generation. Overall, utility-scale solar across all regions contributes only a fraction of a percentage to total generation.

Meanwhile, in terms of the type of fuel, the Form 923 data show that most electricity was generated by natural gas in 2019 (1,582 million MWh; Table 3) followed by coal (965 million MWh). This differs from the 2013 trend, when electricity was generated primarily by coal. Interestingly, total annual net generation has changed very little over the seven years 2013 to 2019.

Note that the fuel groupings shown in Table 3 are more aggregated than the fuel types presented in the EIA Forms (and thereby in the full MEEDE dataset). For instance, coal in the EIA Forms is categorized into bituminous, sub-bituminous, anthracite, and more. While we do not show these groupings in Table 3, fuel type-prime mover pairs are an important part of the data because they allow us to attribute the economic costs of generation in the next section.

Table 3: Annual net electricity generation from EIA Form 923 by fuel, 2013-2019 (in thousands of MWh)

	Annual Net Generation (Thousands of MWh)						
Type	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Coal	1,586,100	1,585,806	1,351,017	1,243,511	1,207,435	1,151,497	965,196
Natural Gas	1,121,215	1,122,676	1,320,041	1,376,748	1,294,531	1,465,410	1,582,594
Nuclear	789,016	797,166	797,178	805,694	804,950	807,084	809,409
Hydropower	263,851	253,168	243,940	261,126	293,831	286,609	282,569
Wind	167,697	181,204	190,641	226,926	254,211	272,601	294,810
Petroleum	24,228	26,338	24,075	20,959	18,823	21,584	15,301
Geothermal	15,775	15,877	15,918	15,826	15,855	15,967	15,473
Solar	8,951	17,556	24,745	35,945	53,135	63,571	71,829
Other	86,959	88,456	89,465	88,798	87,875	87,864	83,118
Total	**4,063,792**	**4,088,246**	**4,057,021**	**4,075,533**	**4,030,646**	**4,172,188**	**4,120,300**

As previously discussed, Form 923 also provides boiler-level details on the type and quantity of fuel inputs. Table 4 presents the heat (Btu) quantities of fuel consumption by various types of fuel. Natural gas accounts for 53 percent of fuel combustion in electricity generation relative to 45 percent for coal in terms of Btu (based on totals in the Btu column in Table 4). Table 4 also shows the pollutant content (sulfur and ash) for the fuel types. Coal is the primary sulfur- and ash-bearing fuel, followed by oil and other petroleum derivatives. Of the two dominant types of coal burned for electricity, bituminous has a higher sulfur and ash content than sub-bituminous. Meanwhile, natural gas has negligible ash and sulfur content.

Lastly, the percentage of net fossil fuel generation that is controlled by each environmental technology is shown in Table 5. Technologies are grouped by the primary pollutant they are designed to target; however, environmental control technologies influence emissions of multiple pollutants. This is particularly true with respect to mercury. The EIA Form 860 data identify 33 specific pollution control technologies (and one "other" category). The majority of these are end-of-pipe controls, but, for nitrogen in particular, there are a number of change-in-process controls. These controls rely primarily on changes to how boilers are operated and may require less physical equipment relative to an end-of-pipe technology like a sulfur scrubber or particulate baghouse. Change-in-process technologies are labeled with an asterisk in Table 5. Boilers use control technologies in over 1,000 different configurations ranging from no controls to nine control technologies. The prevalence of

Table 4: U.S. electric grid fuel heat, sulfur, and ash content, 2019

Fuel Code			Pollutant Content (%)			Volume/Mass	
	Fuel Code	Description	Sulfur	Ash	BTU (Quadrillion)	Quantity	Units
Coal	BIT	Bituminous coal	2.41	10.29	3.12	142.62	MM Sh. Ton
Coal	SUB	Subbituminous coal	0.35	6.04	3.77	222.58	MM Sh. Ton
Coal	COL	Other coal	1.13	10.43	3.24	183.08	MM Sh. Ton
			0.00	0.00		102.87	Bn. Cu. Ft.
Gas	GAS	Natural gas & propane	0.00	0.00	11.98	11,205.58	Bn. Cu. Ft.
Gas	OGS	Other gases	0.00	0.00	0.24	1,069.70	Bn. Cu. Ft.
Oil	OIL	Oil & petroleum deriv.	0.55	0.00	0.20	17.93	MM Barrels
			0.50	0.00		0.01	Bn. Cu. Ft.
			5.08	0.80		3.32	MM Sh. Ton
Other	BML	Biomass liquids	0.00	0.00	0.00	6.24	MM Barrels
Other	BMS	Biomass solids	0.00	0.00	0.35	116.77	MM Sh. Ton
Other	MSW	Municipal solid wastes	0.00	0.00	0.26	28.89	MM Sh. Ton
Other	OTH	Miscellaneous other	0.00	0.00	0.02	8.46	MM Sh. Ton

Note: "Other coal" includes both solid and gaseous coal forms, including Coal-Derived Synthesis Gas.

control technologies varies significantly by region. For example, the Hawaiian Islands Coordinating Council (HICC), Northeast Power Coordinating Council (NPCC), and Alaska Systems Coordinating Council (ASCC) regions have relatively little fossil fuel generation equipped with sulfur, particulate, or nitrogen control technologies, whereas RFC and SERC have relatively high fractions of fossil fuel generation equipped with these controls.

2.2 Economics

Given a full technological and environmental characterization of the grid (see the engineering section above), we specify the economic costs associated with electricity generation and pollution control. We categorize cost components for generation and abatement technologies as either overnight capital or fixed or variable operations and maintenance (O&M) costs and separate them by equipment (i.e. generation and all associated abatement equipment). In all, the economic characterization can provide an estimate of the capital, labor, energy, and materials requirements for operating the electric grid. These costs are produced at the level of individual installations of generation and pollution abatement equipment in true bottom-up fashion. They can be readily summarized at higher-level regional or technology aggregations for modeling applications for comparison with other cost or wholesale revenue estimates.

2.2.1 Generation Costs: Annual Technology Baseline 2020

Data Assembly

We use capital (CAPEX) and O&M expenditure estimates from the 2020 edition of the National Re-

Table 5: Percent of net MWh fossil fuel generation with environmental controls per region, 2019 (%)

Control Equipment Type	Control ID	ASCC	HICC	MRO	NPCC	RFC	SERC	TRE	WECC	Total USA
Sulfur Control Technologies		**10.1**	**15.9**	**51.2**	**1.0**	**42.3**	**25.7**	**22.6**	**38.2**	**32.6**
Circulating dry scrubber	CD	0.0	0.0	6.0	0.1	1.1	0.3	0.0	0.8	1.1
Dry sorbent (powder) injection type (DSI)	DSI	10.1	15.8	3.8	0.0	5.9	6.4	1.5	1.0	4.4
Jet bubbling reactor (wet) scrubber	JB	0.0	0.0	0.0	0.0	3.9	2.4	0.0	0.0	1.8
Mechanically aided type (wet) scrubber	MA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Packed type (wet) scrubber	PA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Spray dryer type / dry FGD / semi-dry FGD	SD	5.5	0.1	21.9	0.0	2.0	2.6	1.7	10.3	5.4
Spray type (wet) scrubber	SP	0.0	0.0	19.5	0.9	28.7	17.7	18.9	16.8	19.7
Tray type (wet) scrubber	TR	0.0	0.0	0.0	0.0	9.3	1.8	1.8	5.8	3.9
Venturi type (wet) scrubber	VE	0.0	0.0	2.5	0.1	0.0	0.1	0.0	3.4	0.8
Particulate Control Technologies		**19.6**	**15.9**	**60.2**	**4.1**	**45.9**	**33.8**	**26.9**	**33.2**	**37.2**
Baghouse (fabric filter), pulse	BP	15.4	0.0	31.7	0.1	7.3	9.1	7.1	11.7	10.8
Baghouse (fabric filter), reverse air	BR	4.3	15.8	9.4	0.0	0.6	1.4	6.8	11.4	4.1
Baghouse (fabric filter), shake and deflate	BS	0.0	0.0	1.9	0.0	0.0	0.0	0.8	0.0	0.3
Electrostatic precipitator, cold side, with flue gas conditioning	EC	0.0	0.0	6.1	0.1	6.1	7.6	4.2	2.3	5.6
Electrostatic precipitator, hot side, with flue gas conditioning	EH	0.0	0.0	2.4	0.2	0.0	0.2	0.0	0.0	0.3
Electrostatic precipitator, cold side, without flue gas conditioning	EK	0.0	0.0	16.0	3.4	32.6	19.0	7.9	6.0	17.9
Electrostatic precipitator, hot side, without flue gas conditioning	EW	0.0	0.0	5.1	0.2	1.7	3.0	0.0	3.4	2.5
Multiple cyclone	MC	5.9	0.0	0.7	0.3	0.0	1.6	0.0	0.7	0.8
Single cyclone	SC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nitrogen Control Technologies		**12.2**	**15.9**	**71.6**	**27.3**	**61.7**	**49.6**	**45.7**	**55.0**	**54.0**
Advanced overfire air*	AA	0.0	0.0	10.9	0.4	0.1	0.2	2.5	9.7	3.0
Biased firing*	BF	0.0	0.0	0.0	0.0	0.2	0.0	0.2	0.0	0.1
Fluidized bed combustor*	CF	0.0	15.8	1.7	0.1	1.3	1.3	1.2	0.3	1.2
Flue recirculation*	FR	0.0	0.0	1.0	0.5	0.7	1.1	1.2	0.3	0.9
Fuel reburning*	FU	0.0	0.0	0.0	0.1	0.0	0.7	0.0	0.1	0.3
Water injection*	H2O	2.1	0.0	0.1	2.9	0.2	0.4	0.2	0.0	0.4
Low excess air*	LA	5.5	0.0	0.6	1.6	0.1	1.6	1.1	0.7	0.9
Low NOx burner*	LN	4.3	0.0	58.4	12.4	41.0	29.4	33.9	43.6	36.9
Ammonia injection*	NH3	5.5	0.0	2.6	3.7	6.9	2.0	5.2	8.4	4.6
Overfire air*	OV	4.3	0.1	48.1	5.5	19.8	18.0	16.0	19.3	20.9
Selective noncatalytic reduction	SN	4.3	15.8	8.7	0.3	4.1	3.3	1.9	4.1	3.9
Selective catalytic reduction	SR	5.8	0.0	25.8	20.0	50.6	34.2	22.7	24.4	33.7
Steam injection*	STM	0.0	0.0	0.0	0.2	0.1	0.2	0.3	0.3	0.2
Mercury Control Technologies		**0.0**	**0.0**	**52.9**	**0.2**	**11.1**	**19.8**	**26.8**	**26.8**	**22.2**
Activated carbon injection system	ACI	0.0	0.0	52.7	0.2	10.9	19.2	26.8	26.8	21.9
Lime injection*	LIJ	0.0	0.0	2.4	0.1	0.3	1.3	0.0	0.0	0.8
Other	**OT**	**0.0**	**0.0**	**6.9**	**0.0**	**1.2**	**2.0**	**0.0**	**10.1**	**3.2**
Total fossil fuel generation (Millions of MWh)		**3.5**	**8.3**	**262.2**	**99.8**	**595.9**	**937.6**	**291.0**	**393.2**	**2,591.5**

Note: Change-in-process technologies are marked with an asterisk.

newable Energy Laboratory Annual Technology Baseline (National Renewable Energy Laboratory, 2021) to estimate the generation costs of new installations. The NREL ATB provides cost information for over 20 technologies with particular focus on renewable technologies including onshore and offshore wind, utility-scale solar PV, hydropower, geothermal, biomass power, and battery storage. As our focus is on estimating capital and compliance cost of the current operating fleet, which is becoming more dominated by renewable and natural gas-fired technologies, we elect to use the ATB cost information over other potential sources. Other sources for cost data are discussed in the "Data Assumptions" section.

For some renewable technologies, such as onshore wind and hydropower, there is further classification of CAPEX values based on resource potential. Fossil technologies (coal and natural gas) have a range of CAPEX values depending on whether carbon capture controls are included. Finally, for other technologies like nuclear, ATB reports only one CAPEX value. For the relevant generating sources, the costs of pollution controls such as nitrogen oxides (NOx) and sulfur oxides (SOx) technologies are included in the capital expenditure in ATB. Regional variability in CAPEX is not incorporated into ATB. Costs could be weighted using the regional indices from the Integrated Planning Model Version 6 (U.S. Environmental Protection Agency, 2018), but that variation is modest and we do not incorporate it here.

We map the ATB cost information onto Form 860 power plants based on their PM-FT configuration. EIA prime movers without ATB cost information include compressed air energy storage, pumped storage, flywheel energy storage, hydrokinetic axial flow turbines, hydrokinetic wave buoys, and fuel cells. We do not fill these with substitute capital and O&M expenditure data, but these units account for less than 0.05 percent of total net generation across the 7 years of EIA data.

The NREL ATB data has been released annually since 2015. Costs in each ATB release, including the 2020 version, are projected for multiple years beginning in the base year. We apply the base year cost data (2020) from ATB 2020 and do not use costs from projected years, as these data are modeled rather than historical. To produce annual capital cost amounts, we amortize overnight capital costs for 30 years at a weighted average cost of capital of 5.5 percent per ATB assumptions (National Renewable Energy Laboratory, 2021). Installations older than 30 years are set to operate with no capital cost of life extension (i.e., amortized value of overnight capital times zero percent). This is a limitation of the dataset and the true sector-wide generation cost might be higher than in MEEDE due to the presence of life extension costs in the real world.

Variable costs exclude fuels and include materials costs such as water and chemical solvents used in operating the generation and control equipment. Fixed O&M costs pertain largely to labor expenses incurred in the daily operations of the plant (U.S. Energy Information Administration, 2020).

Data Assumptions

The generation cost estimates from ATB are for new installations only. Applying these cost estimates to facilities with a wide variety of vintages leads to an inaccurate assessment of their true costs. True capital costs are likely lower and O&M costs higher than the ATB estimates. Capital costs from ATB are reduced through the amortization of overnight costs, which mitigates this limitation, but the overall level is likely still higher than those prevailing at construction time for older-vintage installations. This limitation could be mitigated with better available data; however, data for new installations are often proprietary and difficult to obtain.

Relately, the cost data from ATB represents fewer generation technology specifications for fossil fuel generators than the EIA Forms 923 and 860 data provide. For example, coal CAPEX (in \$/kW) in ATB is estimated for an advanced supercritical power plant, but there are coal plants in the EIA dataset with different boiler technologies (e.g., subcritical boilers), which would lead to different capital costs. Here, we assume that the costs from ATB can be applied to all of the fossil fuel plants within each EIA technology specification. This likely results in MEEDE having higher than expected total capital expenditure for these units because new builds from ATB likely include higher efficiency boilers than found at older vintage plants.

Note that while the ATB data gives us lower cost resolution for fossil fuel technologies compared to other data sources (discussed in more detail below), it gives higher resolution cost information for renewable technologies. For example, land-based wind is categorized into ten cost classes based on wind speed range. Here, we apply the average cost across the ten wind classes, but note that this data could be leveraged in future versions of MEEDE. As previously mentioned, due to the increased penetration of renewables on the grid in recent years, we elect to use data with higher resolution of renewable technology costs.

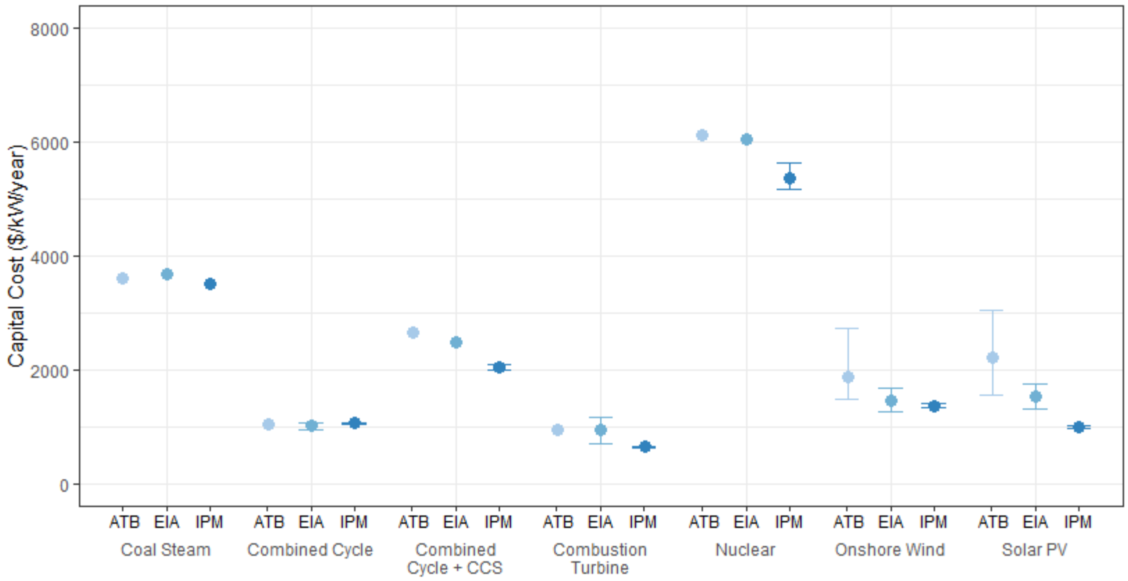
Alternative sources for capital and O&M expenditure data include the EPA's Integrated Planning Model (IPM) and the EIA's National Energy Modeling System (NEMS). The EPA IPM dataset presents cost data for a similar set of technologies as in ATB, but has added regional and age-dependent variability (U.S. Environmental Protection Agency, 2018). However, IPM has fewer classifications within renewable technologies than the ATB data, for example, in comparison with ATB's land-based wind cost classes as described above. Moreover, the IPM cost data is not released annually but rather when there is a model update. We do not use IPM for total capital and O&M information but we do use it for air pollution control technology costs, discussed in more detail in the "Pollution Control Equipment Costs" section.

It should be noted that IPM relies on FERC Form 1 as its underlying source for historical plant-level capital and O&M cost data. FERC Form 1 is publicly available and provides plant-level financial and operational information reported annually by major electricity utilities across the U.S. (Federal Energy Regulatory Commission, 2023). The primary benefit of FERC Form 1 is that the cost data are reported by those subject to the jurisdiction of the Federal Energy Regulatory Commission, and thus have broad coverage and high fidelity. The major disadvantage of FERC Form 1 is that the raw data is time consuming to parse and clean. As such, most users of FERC Form 1 rely on paid data services like Energy Velocity or S&P for cleaned versions of the data, which decreases the transparency of the data. The use of FERC Form 1 can be explored in future MEEDE updates, and could potentially rely on the Catalyst Cooperative's open-source efforts to clean FERC Form 1 (Catalyst Cooperative, 2023).

The EIA National Energy Modeling System cost dataset uses a top-down capital cost estimation methodology derived from parametric evaluations of costs from actual or planned projects (U.S. Energy Information Administration, 2019a). The data cover a similar set of technologies to ATB and IPM, and do not provide regional or age variability. Unlike the ATB data, the NEMS data do not provide a wide range of classifications within specific renewable technologies.

Figure 1 shows a comparison of capital costs for select technologies between the ATB, IPM, and EIA sources. These represent the original data and are not the costs after being mapped to EIA's EGUs. The ranges mark the minimum and maximum costs of each technology from each data source, where the ranges within each technology type come from differences in technology specifications (e.g., the different wind classes for onshore and offshore wind). The dots indicate either the given value (for single points without a range) or the mean value (for points with a range).

Figure 1: Capital cost comparison between data sources for select technologies



Abbreviations: CCS = carbon capture and storage.
Note: The error bars mark the minimum and maximum costs of each technology from each data source. The absence of error bars on some points does not indicate greater precision.

2.2.2 Pollution Control Equipment Costs: Integrated Planning Model Version 6

Data Assembly

In MEEDE, the costs of air pollution control equipment are developed separately from other costs of generation for two reasons. First, the control technologies of a power plant can change through time, so separate accounting of control equipment costs allows calculations of total generation costs to properly reflect the changing controls. Second, in the broader application of MEEDE for the social accounting matrix, this information can be used to demonstrate how abatement activities can be accounted for separately in a disaggregated framework. See Section 3 for a discussion of the application of MEEDE for a social accounting matrix.

As previously mentioned, the ATB total generation cost estimates we use are for new installations of technologies and are inclusive of air pollution control costs required of new units. Thus, to estimate the costs of generation alone, we subtract the cost estimates for pollution controls. Pollution control cost estimates come from EPA's IPM Version 6 (U.S. Environmental Protection Agency, 2018). New coal builds include sulfur oxides and nitrogen oxides controls based on ATB documentation. We specifically assume the use of limestone forced oxidation scrubbers and selective catalytic reduction systems, even though this level of detail is not provided by ATB. We also assume that the capital and O&M costs of new natural gas builds do not include SOx and NOx controls because this is not explicitly specified in ATB documentation. We do assume that both coal and natural gas ATB costs include activated carbon injection with an existing baghouse for mercury and particulate matter control. A generation-only cost estimate enables us to build up the total costs from the generation and pollution control cost components for any configuration that may be operating on the grid.

In order to build up to total costs from the generation-only and IPM control technology costs, we need to first map the variety of control technologies identified in the Form 860 data to the smaller set of technologies that IPM covers. Depending on the technology, this mapping varies with the type of fuel, the firing configuration of the boiler, and the specific control equipment installations. Table 6 provides the total costs of generation and pollution control. Controlling sulfur oxides requires the greatest expense (sum across all SOx control technologies), and total nitrogen oxides and particulate matter controls are each less than half the cost of sulfur oxide control. Approximately one third of all grid generation (1,422 million MWh) employs some form of pollution control. Table 7 shows total capital, fixed O&M, and variable O&M costs for select prime movers across the EIA power plants using calculated generation-only costs with added IPM control costs.

Data Assumptions

The approach we use to integrate ATB and IPM cost data has some limitations. First, IPM's pollution control cost estimates are based on retrofitted installations whose costs likely differ from new installations. Two factors address this concern: (1) older installations are more likely to have installed their control equipment as retrofits, making the estimates appropriate, and (2) for new installations, the control equipment costs will still be included in the total costs of the installation; the adjustment for control equipment only shifts costs between generation and control.

Second, our method for determining generation-only costs makes assumptions about the specific control equipment that are included in ATB capital costs costs for each fossil fuel technology. For instance, the ATB data includes NOx controls in the costing of new coal units, but it does not specify whether it uses selective catalytic reduction equipment, low NOx burners, or another technology. Our specific assumptions might differ from what is actually considered in the ATB cost data. This limitation could be addressed in the future if more granular information on the specific control technologies considered in the ATB cost data becomes available.

2.2.3 Fuel Costs: Energy Information Administration Form 923

Data Assembly

The Form 923 data provide fuel costs and quantities at the PID-FT level but do not attribute these to the boiler level. As such, we use local, quantity-weighted average prices for the different fuel types to estimate total fuel costs for each BID-PID pair. The locality of the average varies depending on data availability (i.e., where a state-level average is not available, we take a regional average if available, a national average if not). Given fuel price data and estimates for capital and O&M costs, we fully cost the generation capital, labor, energy, and materials inputs where we associate fixed O&M with labor and variable O&M with materials.

Data Assumptions

The fuel receipts found in EIA Form 923 are retail or delivered prices and not wholesale prices. Wholesale fuel price data might be preferred in some instances such as when using MEEDE in a social accounting matrix that applies wholesale prices. A method for determining wholesale fuel prices is through mapping the contract start year for each fuel receipt to the EIA wholesale price

Table 6: Costs of generation and pollution control, 2019

Installation Attribute		Total Costs Excluding Fuel (MM 2019$)			
Cost Component	**Net Generation (in thousands of MWh)**	**Capital**	**Fixed O&M**	**Variable O&M**	**Total**
Total system, excluding fuel	**4,120,300**	**85,094**	**56,171**	**15,428**	**156,693**
Generation only	**4,120,300**	**80,008**	**52,770**	**9,428**	**142,206**
Controls	**1,422,334**	**5,086**	**3,401**	**5,999**	**14,486**
SOX Controls	**873,182**	**2,278**	**2,593**	**3,356**	**8,226**
Limestone forced oxidation scrubber	639,225	1,344	1,985	2,443	5,772
Lime spray dryer scrubber	249,216	1,131	859	1,032	3,022
Dry sorbent injection	117,034	246	342	1,054	1,642
PM Controls	**1,009,184**	**1,341**	**372**	**79**	**1,792**
Electrostatic precipitator (cold side)	621,454	349	224	49	621
Fabric filter baghouse	414,560	977	171	38	1,185
Electrostatic precipitator (cold side), with flue gas conditioning	145,072	88	44	11	144
Electrostatic precipitator (hot side)	91,291	235	53	9	298
Electrostatic precipitator (hot side), with flue gas	11,185	107	8	1	117
NOX Controls	**1,406,151**	**1,432**	**416**	**1,120**	**2,969**
Selective catalytic reduction	875,431	1,325	307	966	2,599
Low-NOx burner (wall fired)	687,370	1,074	269	764	2,107
Low-NOx burner with advanced overfire air (tangentially fired)	303,937	25	48	6	80
Low-NOx burner with overfire air (wall fired)	251,206	579	147	396	1,122
Selective noncatalytic reduction (fluidized bed)	18,208	21	3	53	77
Vertically fired	4,584	15	1	7	23
HG Control - Active Carbon Injection	**586,773**	**35**	**20**	**1,444**	**1,498**

Abbreviations: Hg = mercury; MWh = megawatt-hour; NOX = nitrogen oxide; O&M = operations and maintenance; PM = particulate matter; SOX = sulfur oxide.
Notes: Total system cost = cost of generation plus cost of controls. Amounts do not sum across controls because many installations run multiple controls (e.g., selective catalytic reduction with a low-NOx wall-fired burner).

data from the corresponding year. While Form 923 does not currently provide information on the contract start date for each fuel receipt (it provides only the contract end date), it might do so in the future.

2.2.4 Wholesale Prices: Federal Energy Regulatory Commission Form 714

Data Assembly

The final step in costing is to estimate the wholesale value of the electricity produced. Wholesale electricity price data is useful for assessing the revenue from wholesale electricity sales in the U.S. Note that this can differ substantially from the retail price of electricity for a variety of reasons, particularly in regulated markets (Cappers and Murphy, 2019). We do not assess electricity sector

Table 7: Capital and O&M costs across EIA power plants for select prime movers, 2019

Installation Attribute			Total Costs Including Pollution Control Technologies (MM 2019$)		
Prime Mover Type	Code	Net Generation (in thousands of MWh)	Capital Cost	Fixed O&M Cost	Variable O&M Cost
Combined Cycle (Steam)	CA	429,811	1,789	296	1,006
Combined Cycle (Single)	CS	58,808	1,081	195	133
Combined Cycle (Combustion)	CT	860,912	20,324	3,563	1,922
Gas Turbine	GT	136,102	9,792	2,113	651
Hydraulic Turbine	HY	287,830	1,940	7,340	0
Internal Combustion (Diesel)	IC	16,005	589	145	77
Photovoltaic	PV	68,611	4,328	740	0
Steam Turbine	ST	1,965,224	29,205	36,602	11,635
Wind (Onshore)	WT	294,693	15,306	4,955	0

Note: Amounts do not sum to totals because these show a selection of all prime mover types).

revenue from retail sales. For estimating the wholesale value, we rely on data from FERC Form 714, which are available for years 2006 to 2019 (Federal Energy Regulatory Commission, 2021).

The FERC Form 714 provides hourly system marginal cost ($/MWh) and hourly electricity demand (MWh) data for over 200 balancing authority areas (BAs). The system marginal cost (or the "system lambda") is the marginal cost of the generating plant that meets the last MWh of electricity demanded. We use the hourly electricity demand to weight the system lambda data, whereby hours with greater electricity demand volume have higher weights for the system lambda.

In order to map FERC's BA-level data to the plant-level data produced in EIA Forms 860 and 923, we match Form 860's Balancing Authority Code for each PID to Form 714's respondent ID description. Approximately 65 percent of BID-PID pairs in 2019 can be matched to a FERC respondent ID. This percentage is lower for earlier EIA years (56 percent in 2013) due to discrepancies and changes in FERC respondent IDs, which resulted in more gaps when mapped to the EIA data. Plants without available Balancing Authority Codes across all years are assigned the NERC region volume-weighted average price. These plants are primarily in the Alaska Systems Coordinating Council (ASCC) and the Hawaiian Islands Coordinating Council (HICC). In 2019, the U.S. average annual wholesale price of electricity was around $30/MWh, which aligns with other sources such as the U.S. EIA.

Because FERC Form 714 data are available at the hourly level, we aggregate the values into lower temporal resolution. Specifically, for each balancing area in each year from 2013 to 2019, we report the annual weighted system lambda in dollars per MWh generated. The hourly-level data can be aggregated in any way required by the user, for example by month or season.

Data Assumptions

In collecting the wholesale cost data and assigning a value to each EIA plant based on the balancing area, we make two main assumptions. First, we assume that the plants within each EIA Balancing Authority Code overlap entirely with the plants covered by each corresponding Form 714 respondent ID. For example, FERC Form 714 lists "Southern Company" as a respondent, which we then matched to EIA BA Code "SOCO". All plants with Balancing Authority Code "SOCO" would then be assumed to fall under FERC balancing area "Southern Company". However, it is possible that there are discrepancies between the FERC and EIA datasets in terms of which plants fall under each balancing authority.

Second, we assume that state-level averages are representative estimates for plants where FERC data is not available. Utilities that are not required to report Form 714 may have different wholesale cost and demand profiles than those required to report. However, without additional information indicating where these differences may occur, the most reliable approximation is to use state-wide averages based on available data.

An alternative source for wholesale price data is the Intercontinental Exchange (ICE), which reports wholesale daily spot prices at hubs across the U.S. The prices listed on the ICE are only those for deregulated markets so may differ from the data provided in FERC Form 714.

2.2.5 Economic Data Description

Table 8 shows the capital costs (in $/MWh) for the technology configurations used to make the MEEDE dataset. The generation-only costs columns show the revised costs net of included control equipment as costed from IPM Version 6. This adjustment affects all coal and natural gas technologies. Control equipment cost adjustments vary by technology and are greatest for coal units (up to 25 percent). With the exception of carbon capture and sequestration controls, control cost adjustments for combined-cycle plants are relatively minor (3 to 10 percent difference between generation-only and EIA total costs).

Meanwhile, Table 9 summarizes the total generation costs or expenditures (generation plus controls) for the different plant types by region. Advanced supercritical coal installations dominate by total generation costs across all regions, followed by natural gas combined cycle and combustion turbine plants. Between regions, the South Atlantic (SERC) has the highest overall costs because the greatest number of plants exist in these states. The West North Central states (MRO) have high coal and gas total generation costs but low solar generation costs, due to lower prevalence of solar installations. The WECC region has similar coal generation costs but much higher solar generation costs.

Lastly, Table 10 summarizes the wholesale revenue and total costs of electricity generation by region. The national wholesale revenue—again, represented by hourly system lambdas—is slightly more than half of total cost. This does not necessarily indicate that sector-wide costs of generation are greater than revenue earned. Rather, this can be at least in part attributed to the regional differences in wholesale prices and other sources of generator revenue (e.g., ancillary service markets). Wholesale prices may be far less than total system revenue. Depending on the market, retail prices of electricity can be more than two times the wholesale price of generation (Cappers and Murphy, 2019) as retail prices include taxes and state surcharges, costs of delivery, and purchasing costs in addition to generation and ancillary service costs. In recent years, changes in retail prices have

Table 8: Total capital and O&M costs and generation-only capital and O&M costs by plant type

	ATB Total Costs			Generation-Only Costs		
Configuration	Capital ($/MW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)	Capital ($/MW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)
Coal						
Advanced Supercritical Coal Avg CF + CCS	6.06	0.06	8.83	4.95	0.05	7.23
Advanced Supercritical Coal High CF + CCS	6.06	0.06	8.83	5.03	0.05	7.23
Coal IGCC Avg CF	4.74	0.06	7.88	3.69	0.05	6.39
Coal IGCC High CF	4.74	0.06	7.88	3.77	0.05	6.39
Advanced Supercritical Coal Avg CF	4.15	0.04	4.40	3.10	0.03	2.91
Advanced Supercritical Coal High CF	4.15	0.04	4.40	3.18	0.03	2.91
Natural Gas						
Natural Gas Combined Cycle Avg CF	1.09	0.01	2.16	0.99	0.01	2.01
Natural Gas Combined Cycle High CF + CCS	2.78	0.03	5.72	2.68	0.03	5.56
Natural Gas Combined Cycle High CF	1.09	0.01	2.16	0.99	0.01	2.01
Natural Gas Combustion Turbine Avg CF	0.98	0.01	4.50	0.89	0.01	4.34
Nuclear						
Advanced Nuclear	7.19	0.12	2.32	7.19	0.12	2.32
Renewables						
Biomass	4.35	0.12	4.72	4.35	0.12	4.72
Concentrated Solar Power	7.83	0.07	4.20	7.83	0.07	4.20
Geothermal – Binary	8.70	0.18	0.00	8.70	0.18	0.00
Geothermal – Dual Flash	6.70	0.14	0.00	6.70	0.14	0.00
Onshore Wind	1.96	0.04	0.00	1.96	0.04	0.00
Hydropower New Stream-Reach Development	6.95	0.08	0.00	6.95	0.08	0.00
Offshore Wind	5.34	0.11	0.00	5.34	0.11	0.00
Solar Photovoltaic	1.60	0.02	0.00	1.60	0.02	0.00

Abbreviations: Avg CF = average capacity factor; CCS = carbon capture and storage; High CF = high capacity factor; IGCC = integrated gasification combined cycle.
Note: Generation-only costs equal ATB total costs less EPA Integrated Planning Model retrofit costs of the ATB technology specification's control equipment.

become decoupled farther from wholesale prices and the costs of generation (Cappers and Murphy, 2019). This is particularly so in regulated markets (e.g., SERC) where retail revenue can support cost recovery for integrated utilities' generation assets. Table 10 indicates considerable regional variation, with some regions presenting greater discrepancy between total costs and wholesale revenue (e.g., SERC). The MEEDE dataset's estimated annual cost of operating generation and control

Table 9: Total generation cost by plant type and region, 2019

	Generation Costs (MM 2019$)								
ATB Technology	MRO	NPCC	RFC	SERC	TRE	WECC	ASCC	HICC	Total USA
Advanced Nuclear	697	2,062	5,182	7,744	2,100	1,160	0	0	18,946
Advanced Supercritical Coal Avg CF	5,935	990	4,941	8,382	1,352	3,939	53	784	26,377
Advanced Supercritical Coal High CF	5,596	704	15,657	20,344	6,275	5,379	0	0	53,955
Biomass	550	395	789	2,715	86	483	0	57	5,076
Coal IGCC Avg CF	0	0	493	0	0	0	0	0	493
Concentrated Solar Power	0	0	0	587	0	757	0	0	1,344
Geothermal – Binary	0	0	0	0	0	870	0	0	870
Geothermal – Dual Flash	0	0	0	0	0	566	0	0	566
Hydropower New Stream-Reach Development	507	726	407	1,748	55	5,661	162	13	9,280
Natural Gas Combined Cycle Avg CF	2,512	4,253	7,295	16,015	4,955	9,168	212	358	44,768
Natural Gas Combined Cycle High CF	479	722	4,675	7,988	2,072	1,206	0	0	17,142
Natural Gas Combustion Turbine Avg CF	2,144	880	4,218	6,350	1,088	2,842	260	128	17,911
Offshore Wind	0	16	0	0	0	0	0	0	16
Onshore Wind	7,530	671	2,251	421	5,023	4,312	12	40	20,261
Solar Photovoltaic	172	226	286	1,402	343	2,658	0	38	5,126

Abbreviations: Avg CF = average capacity factor; High CF = high capacity factor; IGCC = integrated gasification combined cycle.
Regions: ASCC = Alaska Systems Coordinating Council; HICC = Hawaiian Islands Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.
Note: Recall that each unit in MEEDE is assigned a cost from one of these ATB technologies.

equipment in 2019 is $222,452 million (2019 dollars). While wholesale prices in regulated markets do not cover all generation costs, they do cover all variable costs (i.e., fuel and variable O&M), which should be the basis for generators' bids in competitive markets.

Generators have other revenue streams in addition to wholesale revenues. Generators in many regions have opportunities to participate in a variety of auctions and contract types, such as in ancillary service or derivative markets (e.g., futures). Revenue from this type of market participation would not be captured by hourly system lambdas and wholesale revenue. In addition, infrequent and often brief market conditions such as extreme weather events may have outsized impacts on generator revenue from participation in other markets, which are not captured by the wholesale revenue.

On the cost side, the total cost of electricity generation may be smaller in reality than estimated here. This is because MEEDE's amortization of capital costs may differ from the actual annual costs of a plant. For instance, plants may payoff more of their debt obligations in early years when O&M cost are lower than is assumed with a fixed amortization schedule at an assumed debt term of 30 years.

Table 10: Wholesale revenue and total costs by NERC region, 2019

	MM 2019$					
NERC Region	Wholesale Revenue	Fuel Costs	Capital Costs	Fixed O&M Costs	Variable O&M Costs	Total Costs
ASCC	362	370	220	91	18	699
HICC	1,152	1,021	279	101	42	1,444
MRO	11,915	5,602	12,041	6,638	1,849	26,130
NPCC	6,133	3,113	4,316	3,802	483	11,714
RFC	24,894	14,786	14,806	12,691	3,978	46,262
SERC	32,831	24,826	26,279	17,136	5,550	73,790
TRE	11,884	5,668	11,732	4,564	1,385	23,350
WECC	31,006	10,347	15,421	11,148	2,121	39,036
Total USA	**120,177**	**65,732**	**85,094**	**56,171**	**15,428**	**222,425**

Regions: ASCC = Alaska Systems Coordinating Council; HICC = Hawaiian Islands Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.

2.3 Environment

The final step in creating the full MEEDE dataset is to identify the emissions associated with each observation generated in the previous steps. We include emissions data in MEEDE because the electricity sector is a primary contributor of greenhouse gas and criteria pollutant emissions. In the U.S., the electricity sector produces an estimated 25 percent of total greenhouse gas emissions per year (U.S. Environmental Protection Agency, 2021a). Users of the MEEDE dataset can apply the emissions information for example into economy-wide models for simulating changes in total emissions under various scenarios. We estimate emissions for eight pollutants: three greenhouse gases (CO_2, CH_4, N_2O), three criteria pollutants (particulate matter, SOx, NOx), and mercury. For this, we rely on data from a variety of EPA sources, described in more detail in the following sections.

Note that in this update of MEEDE, we do not include emissions from fluorinated gases (F-gases). F-gas emissions from the electricity sector are primarily fugitive emissions from transmission infrastructure, especially from older equipment (U.S. Environmental Protection Agency, 2021b). Because of this, F-gas emissions cannot be readily allocated to generators based on generation capacity or other attributes, and are therefore excluded from MEEDE.

2.3.1 Particulate Matter Emissions: 2018 EPA Mercury and Air Toxics Standards Residual Risk and Technology Review

Data Assembly

Emissions of particulate matter 2.5 in 2018 are compiled for the 2020 Mercury and Air Toxics Standards (MATS) residual risk and technology review (RTR; U.S. Environmental Protection Agency (2017)). This dataset provides particulate matter emissions quantity (annual total in lbs, which we convert to tons) and emissions rate (lbs/MMBtu, converted to tons/MMBtu) for all generating units that were required to report tests which were conducted for compliance with the final MATS rule. These include any fossil fuel-fired combustion units greater than 25 megawatts-electric (MWe) that serve a generator producing electricity for sale (U.S. Environmental Protection Agency, 2011). Unlike many of the other emissions datasets, which are discussed in more detail in the following sections, the particulate matter data are not released annually nor are they presented at sub-annual resolution. Rather, this dataset was produced only in 2018 with one annual average emissions per generating unit. The MATS RTR reports emissions of filterable PM 2.5 but not condensible PM 2.5 or any PM 10.

We map the particulate matter emissions onto EIA Forms 860 and 923 by matching the plant IDs in the MATS RTR with PID in the EIA Forms. While the MATS RTR reports at the generation unit level, we aggregate particulate matter emissions to the plant level for mapping because unit ID codes in MATS RTR do not match BIDs in the EIA Forms. Particulate matter emissions are not equally distributed among BIDs per each PID, but depend on the quantity of fuel input, the fuel type, and the emissions controls associated with each BID, so we have to apportion the particulate matter emissions to each BID-PID pair. To do this, we first use the EPA's AP-42 (U.S. Environmental Protection Agency, 1995) to assign emissions abatement efficiencies to each BID-PID pair based on the associated control equipment. We also use AP-42 to allocate emission factors to each BID-PID depending on the fuel type(s) used. Then, we use each BID-PID's heat input to weight the emissions.

As previously mentioned, not all EGUs report emissions within the MATS RTR due to reporting requirements. We calculate a weighted average emissions rate (tons/MMBtu) by prime mover and fuel type and apply it to non-reporting units. Doing this increases PM emissions by 4 percent relative to the original MATS RTR data.

Data Assumptions

Because annual data is not available for particulate matter emissions, we assume that the 2018 emissions are representative of other years. In reality, it is possible that power plant control equipment configurations change through time, thereby changing the emissions associated with each BID-PID pair. An alternative approach for assigning particulate matter emissions to Forms 860 and 923 is to do so by matching on the control equipment configuration (e.g., all of the possible combinations of SOx, NOx, etc. controls) between the two datasets. For this, we would use data from the 2012 EPA Maximum Achievable Control Technology (MACT) Information Collection Request (ICR) rather than the 2018 MATS RTR because the former reports more detail in terms of the type of pollutant control equipment associated with each generating unit (U.S. Environmental Protection Agency, 2012). However, for this version of MEEDE, we do not take this approach because we elect to use the more recent particulate matter emissions data.

Another uncertainty in the PM emissions data stems from the lack of data for relevant (fossil fuel and other PM emitting) units smaller than 25 MWe, which generated less than 1 percent of electricity output in 2019. In applying the weighted average emissions rates to fill this missing data, we assume that the emissions rates of larger units are representative of smaller units. Without additional information on emissions rates of small EGUs, this method provides the best estimate given available data and should not impact sector-wide results substantially as emissions only increase by 4 percent.

2.3.2 Mercury Emissions: EPA Mercury and Air Toxics Standards

Data Assembly

Mercury emissions are continuously monitored under MATS and available from the EPA Air Markets Program Data (AMPD; U.S. Environmental Protection Agency (2021c)). As with particulate matter emissions under MATS, all fossil fuel-fired combustion units that serve a generator greater than 25 MWe are required to report mercury emissions. Hourly emissions data (quantity given in lbs and rate in lb/MMBtu) from 2015 to 2020 are available per generating unit per plant for all plants that must report under MATS. Because the raw data is hourly, we aggregate the emissions to annual as well as to predefined "time-slice" resolution. These time-slices correspond to NREL's Regional Energy Deployment Systems (ReEDS) model's default 16 time-slices that are meant to represent each of the four seasons as well as four times of day when electricity demand might vary (overnight, morning, afternoon, and evening; Cohen et al. (2019)). MEEDE provides a total of 36 reported statistics for Hg emissions in each year: one annual emissions total (tons), one annual median value to represent the hourly emissions (tons), one annual 25th percentile value (tons), one annual 75th percentile value (tons), 16 time-slice emissions totals (tons), and 16 time-slice median rates (tons/MMBtu).

An interesting point to note is that hourly emissions of mercury can be excessively high when generators are ramping up or down. In the entire hourly time series from 2015 to 2019 for all reporting plants, outlier values (greater than 1.5 times the interquartile range) occurred in less than 5 percent of data. We do not remove these data points from our aggregated annual totals or time-slice medians because they represent real power plant operations and emissions during these times. However, we note that these values could skew the totals and medians in one year compared to another if more frequent ramping occurs (for instance, if coal-fired power plants are treated as load following plants due to the increased penetration of renewable generators).

Similar to the particulate matter data, the unit ID codes presented in the EPA AMPD do not correspond perfectly with the BIDs in the EIA Forms. As such, we aggregate mercury emissions to the plant level and then apportion emissions to each BID-PID pair using abatement efficiencies and emission factors from AP-42, and heat input data from Form 923. Moreover, since not all units report mercury emissions under MATS, we calculate a weighted average emissions rate (tons/MMBtu) by prime mover and fuel type and apply it to non-reporting units. This increases emissions by less than 3 percent relative to the totals reported in the original source.

Data Assumptions

In addition to limitations introduced by the lack of emissions data for smaller EGUs, our use of AP-42 data adds uncertainty to the final mercury emissions as well. The apportionment of plant-level mercury emissions to boiler level relies on AP-42, which was developed based on 1995 data. This is the most accurate data to date because more recent data is not available. As such, we have more confidence in the plant-level emissions estimates than in the boiler-level estimates. In the future, if EPA AMPD reported generation unit codes are able to align more closely with EIA boiler and/or generator IDs (the way that plant IDs are standardized across reporting platforms), then the data could be matched unit-to-unit rather than require allocation using AP-42.

2.3.3 SOx and NOx Emissions: EPA Air Markets Program

Data Assembly

Emissions of sulfur and nitrogen oxides are provided by EPA's Office of Air and Radiation's Clean Air Markets Division and also reported at the hourly level in the AMPD (U.S. Environmental Protection Agency, 2021c). All fossil fuel-fired units serving a large generator (greater than 25 MWe) that provides electricity for sale are required to report SOx and NOx emissions. For units less than 25 MWe that are not required to report, we apply the weighted average emissions rate (lb/MMBtu) by plant and fuel type. Doing this increases SOx and NOx emissions by less than 1 percent each compared to the totals reported in the original sources.

The data provides unit-level emissions that we summarize at the plant level and allocate to the boiler level based on the relative estimates from AP-42 emissions factors. As with mercury emissions, hourly SOx and NOx emissions and emissions rates are aggregated to annual resolution from 2013 to 2019 and time-slice resolution per year.

Data Assumptions

We make the same data assumptions here as we do for PM and particularly mercury. Therefore, the same improvements can be made in future iterations if EPA and EIA reporting units become better aligned.

2.3.4 Greenhouse Gas Emissions: EPA Greenhouse Gas Reporting Program

Data Assembly

Annual emissions of carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) from 2011-2019 are reported by the "Envirofacts" utility of EPA's Greenhouse Gas Reporting Program (GHGRP) at the power plant level (U.S. Environmental Protection Agency, 2021d). Under the Greenhouse Gas Reporting Program (codified at 40 CFR Part 98), facilities that generate more than 25,000 metric tons of CO_2e per year are required to submit annual greenhouse gas emissions reports (U.S. Environmental Protection Agency, 2009). These include emissions quantity and emissions rates. Power plants are assigned GHGRP "Facility IDs" and can be mapped directly to EIA PIDs. Using AP-42 and EIA heat input, we allocate the annual plant-level emissions to the boiler level.

As with the other pollutants, emissions from units without GHGRP data are estimated as a weighted average emissions rate by plant and fuel type. Emissions increase by less than 2 percent for carbon dioxide, 6 percent for nitrous oxide, and 6 percent for methane relative to the totals reported in the original sources.

Data Assumptions

In addition to the assumptions discussed regarding the other air pollutant emissions, further uncertainty is introduced to this dataset through the manual mapping of GHGRP "Facility IDs" to EIA PIDs. Approximately 40 percent of GHGRP power plant facilities are reported with an EIA plant code. The remaining 60 percent are mapped using a supplementary crosswalk between GHGRP facility IDs and EIA PIDs developed by the EPA (U.S. Environmental Protection Agency, 2020). We assume its accuracy but note that there could be erroneous mappings.

2.3.5 Environmental Data Description

Table 11 summarizes the U.S. electricity sector emissions quantity by pollutant and region. The

SERC region has the highest emissions across all criteria pollutants and greenhouse gases, but also has the highest net electricity generation. The Mid-Atlantic and Midwest region (RFC) has the second highest generation as well as the second highest level of emissions for all greenhouse gases and pollutants except mercury. Meanwhile, the U.S. West (WECC) has the third highest net generation but substantially lower SOx emissions than many of the other regions, including MRO and TRE. Table 12 summarizes the U.S. electricity sector emissions rates by pollutant and region. The West North Central states (MRO) have the highest emissions rates across most of the criteria pollutants and greenhouse gases. Meanwhile, Hawaii (HICC) and the New England states (NPCC) have the lowest emissions rates overall. Note that the HICC particulate matter emissions rate is an outlier here, as it is the highest of the eight regions. This is because over 85 percent of the units in Hawaii are oil-fired, which tends to have a higher particulate matter emissions rate.

Table 11: Criteria pollutant and greenhouse gas emissions by region, 2019

	Output	Criteria and Hazardous Air Pollutants (tons)				Greenhouse Gases (MMT CO2e)		
NERC	**Net Generation (in thousands of MWh)**	**Sulfur Oxides**	**Nitrogen Oxides**	**Particulate Matter**	**Mercury**	**Carbon Dioxide**	**Nitrous Oxides**	**Methane**
ASCC	6,068	79	229	62	0.01	0	0.01	0.01
HICC	9,750	407	350	617	0.00	0	0.01	0.01
MRO	447,052	155,125	134,271	10,257	1.50	231	0.86	0.31
NPCC	231,593	2,558	10,666	181	0.01	48	0.04	0.02
RFC	918,960	247,095	199,421	21,279	1.18	425	1.47	0.71
SERC	1,354,551	270,898	253,891	36,514	1.52	582	1.74	0.97
TRE	414,237	106,528	65,224	5,365	1.02	183	0.49	0.27
WECC	738,088	78,558	142,187	17,840	0.81	274	0.86	0.46
Total	**4,120,300**	**861,248**	**806,239**	**92,115**	**6.03**	**1,743**	**5.49**	**2.74**

Regions: ASCC = Alaska Systems Coordinating Council; HICC = Hawaiian Islands Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.

Table 13 illustrates the impact of control technologies on emissions of sulfur oxides. Among coal-fired generators, 94 percent of generation is covered by some type of sulfur control equipment. Limestone forced oxidation (LSFO) and lime spray dryer (LSD) technologies are most prevalent. Emissions rates for controlled equipment are between 38 percent (dry sorbent injection for sub-bituminous coal) and 87 percent (LSFO for sub-bituminous coal) lower than those for uncontrolled generation. The use of multiple control devices can reduce emissions rates by upward of 98 percent.

2.4 Full MEEDE Dataset

The MEEDE dataset provides a highly detailed description of the engineering, economic, and environmental attributes and quantities of the U.S. electric grid at the level of individual generating units. The aggregate quantities maintain good fidelity with estimates from secondary sources, suggesting some success in methodology and construction. Table 14 shows a comparison of total

Table 12: Criteria pollutant and greenhouse gas emissions rates by region, 2019

	Output	Criteria and Hazardous Air Pollutants (tons/MWh)				Greenhouse Gases (tons CO2e/MWh)		
NERC	Net Generation (in thousands of MWh)	Sulfur Oxides	Nitrogen Oxides	Particulate Matter	Mercury	Carbon Dioxide	Nitrous Oxides	Methane
ASCC	6,068	0.013	0.038	0.010	0	72	1.97	1.06
HICC	9,750	0.042	0.036	0.063	0	42	1.04	0.54
MRO	447,052	0.347	0.300	0.023	0	516	1.92	0.69
NPCC	231,593	0.011	0.046	0.001	0	208	0.18	0.11
RFC	918,960	0.269	0.217	0.023	0	463	1.60	0.77
SERC	1,354,551	0.200	0.187	0.027	0	430	1.29	0.71
TRE	414,237	0.257	0.157	0.013	0	441	1.18	0.65
WECC	738,088	0.106	0.193	0.024	0	371	1.17	0.63
Total	**4,120,300**	**0.209**	**0.196**	**0.022**	**0**	**423**	**1.33**	**0.67**

Regions: ASCC = Alaska Systems Coordinating Council; HICC = Hawaiian Islands Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.

Table 13: Coal-fired emissions of sulfur oxide by boiler-level control type, 2019

		Emissions Rate (tons/MMBTU)			Percent Reduction from Uncontrolled (%)		
Controls	Net Generation (in thousands of MWh)	Other Coal	Bituminous	Sub-Bituminous	Other Coal	Bituminous	Sub-Bituminous
DSI	44,937	0.207	0.239	0.288	53.2	65.1	37.8
DSI+LSD	1,641	0.158	0.284	0.044	64.2	58.6	90.5
DSI+LSD+LSFO	5,807	0.029	0.365	0.000	93.4	46.7	100.0
DSI+LSFO	59,039	0.175	0.144	0.014	60.4	79.0	97.1
LSD	163,801	0.235	0.161	0.109	46.7	76.4	76.5
LSD+LSFO	54,388	0.008	0.161	0.125	98.3	76.4	73.0
LSFO	503,526	0.176	0.128	0.062	60.2	81.3	86.5
No Controls	126,492	0.442	0.685	0.464	0.0	0.0	0.0
All Coal-Fired Generation	**959,630**	**0.231**	**0.143**	**0.180**	**--**	**--**	**--**

Abbreviations: DSI = dry sorbent injection; LSD = lime spray dryer; LSFO = limestone forced oxidation.
Note: Combinations of controls shown here occur at the plant level, not boiler level.

heat input and total fuel expenditures by major fuel type (coal, natural gas, and petroleum) in 2019 between MEEDE and the EIA's State Energy Data System (SEDS; U.S. Energy Information Administration (2019b)). SEDS also relies on EIA Forms 923 and 860, but applies different assumptions and accounting methodologies across its estimates to arrive at the outputs shown in the table. Coal and natural gas fuel consumption between the MEEDE and SEDS are within a few percent of each other, demonstrating consistency between the datasets. Oil consumption, however, differs by almost 15 percent. This is likely a difference in accounting (i.e., which EIA fuel codes are classified as broader "Oil") rather than a discrepancy between the datasets themselves. On the other hand, fuel expenditures diverge between the two datasets by 10-15 percent depending on the fuel type. This indicates a difference in methodology for how state- and census-level fuel prices are calculated. For coal, SEDS estimates fuel prices using unpublished cost data from EIA Form 923 (U.S. Energy Information Administration, 2019b) whereas MEEDE relies only on the publicly-available version of the data. It is possible that the publicly-available data is more heavily weighted towards higher fuel prices. For natural gas, SEDS relies on the EIA "Natural Gas Annual" report, which uses EIA Form 176 data and is distinct from Form 923 (U.S. Energy Information Administration, 2019b). For oil or petroleum, SEDS estimates the price of distillate fuel oil using data from the EIA's Office of Energy Production, Conversion, Delivery (EPCD; U.S. Energy Information Administration (2019b)).

Table 14: Comparison of sector-wide outputs from MEEDE and SEDS, 2019

	Fuel Consumption (Million MMBTU)		Expenditure (MM 2019$)	
Fuel Type	**SEDS**	**MEEDE**	**SEDS**	**MEEDE**
Coal	10,181	10,112	20,948	23,894
Natural Gas	11,674	11,979	33,975	39,950
Oil	188	165	1,689	1,887

The final MEEDE dataset for 2013 to 2019 has 91,296 observations and 133 variables. The data provide a variety of plant-level attributes (e.g., plant name and ID, NERC and census regions, wholesale electricity price) and boiler-level attributes (e.g., fuel type, MMBtu of fuel consumed, emissions rates, and capital and O&M costs). Quantitative boiler-level attributes can be summed over the entire dataset to generate grid totals, whereas plant-level attributes can apply to multiple observations at the boiler level. Generator-level attributes (e.g., nameplate capacity, heat rate) also apply to multiple observations. The data dictionary in Appendix I indicate the attribute level, units (if quantitative), and data source of each variable.

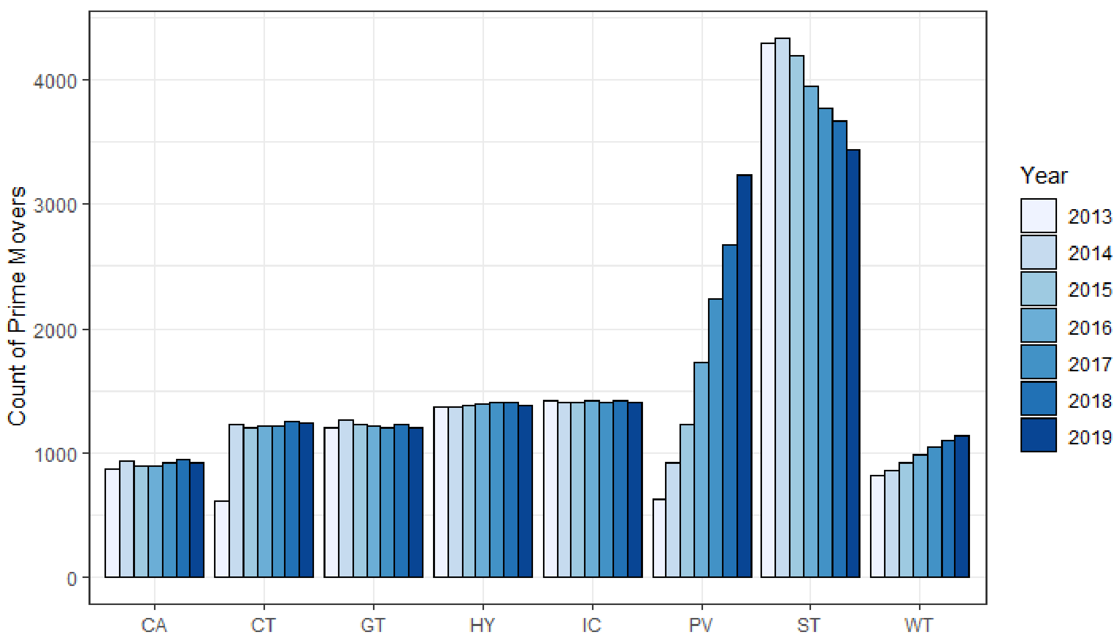
To summarize the previously discussed uncertainties from the construction of the MEEDE dataset, we have greatest confidence in the data provided by the EIA Forms 923 and 860, which includes electricity generation, heat input, and power plant configuration information at the PID-PM-FT-BID level. This data covers an estimated 97 percent of generation capacity in the U.S., and the remainder is comprised primarily of small-scale solar photovoltaic systems (U.S. Energy Information Administration, 2021c). In terms of capital and O&M costs, uncertainty arises from differences between the air pollution control equipment included in the ATB costs and the equipment that we assume ATB includes. This uncertainty is less relevant for renewable and nuclear technologies without air pollution controls. The uncertainty in fuel costs comes mainly from the method we apply to distribute EIA reported fuel cost data to the state, census, and then national level. States and census regions with fewer EIA reported PID-PM-level fuel cost values will be more heavily biased by the data that is available. For wholesale electricity revenue, the greatest uncertainty arises from the method we use to fill missing data. Volume-weighted NERC average prices may be biased if the balancing authorities that do report in FERC Form 714 are not representative of those that do not. Finally, in terms of air pollution emissions, we have greater confidence in the estimates for the greenhouse gases (CO_2, CH_4, N_2O) and NOx and SOx than we do for PM, because of the availability of continuously monitored data. A limitation of the emissions data is the lack of information on smaller EGUs; however, our method for filling missing data increases total emissions by no more than 6 percent across each pollutant relative to the original data, which indicates that these non-reporting EGUs comprise only a small portion of total emissions. An additional limitation of the mercury emissions data is the fact that it only begins in 2015.

2.4.1 Annual Trends

As can be seen in Figure 2, the number of steam turbine generators (e.g., coal) decreased between 2013 and 2019, while the number of solar and onshore wind generators both increased. In 2019, the total number of solar generators was greater than the number of steam turbine generators, not including the steam portion of combined cycle generators. However, in terms of actual electricity generation, solar generates only a fraction of the total even in 2019. The decrease in coal steam turbine net generation was met by primarily by natural gas generation (Table 3).

Due to the decrease in coal generators, along with a variety of other reasons such as increased renewable penetration and emissions regulations, greenhouse gas and criteria pollutant emissions decreased overall between 2013 and 2019 (Figure 3). Between 2013 and 2019, total methane and nitrous oxide emissions from the electricity sector decreased almost 30 percent and 40 percent, respectively. Though not shown here, total CO_2 emissions experienced declines as well, decreasing almost 25 percent between 2013 and 2019.

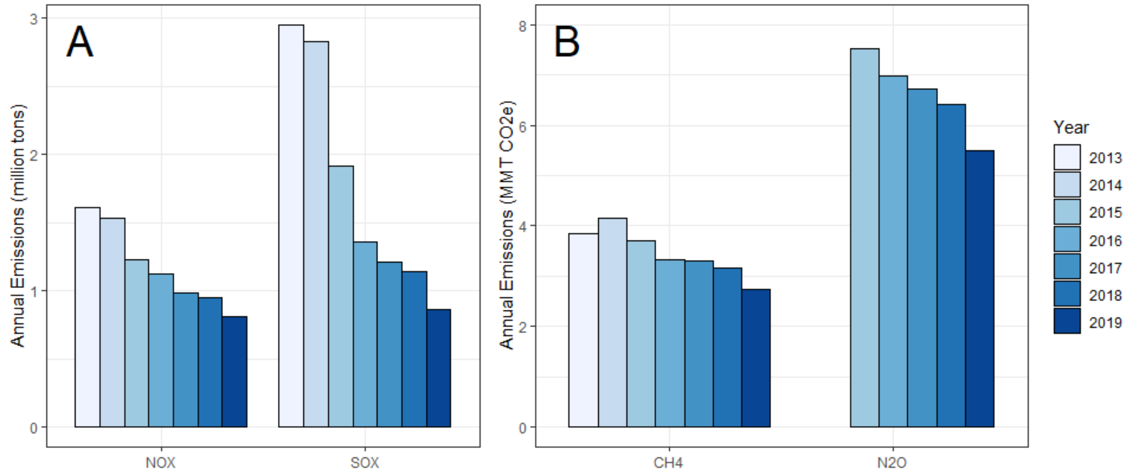
Figure 2: Count of select prime movers in EIA Form 923, 2013-2019



Abbreviations: CA = combined cycle (steam); CT = combined cycles (combustion); GT = gas turbine; HY = hydraulic turbine; IC = internal combustion (diesel); PV = photovoltaic; ST = steam turbine; WT = wind (onshore).

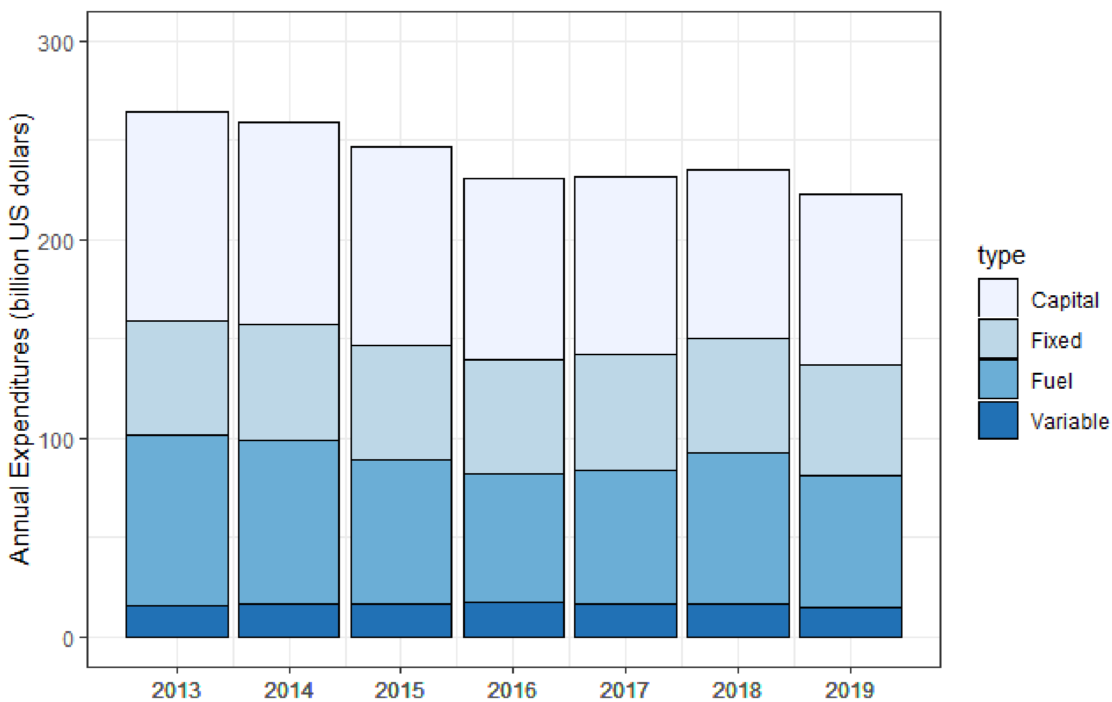
Total annual expenditure has decreased roughly 15 percent between 2013 and 2019 (Figure 4). This

Figure 3: Annual emissions of criteria pollutants (nitrogen oxides and sulfur oxides) and greenhouse gases (methane and nitrous oxide), 2013-2019



Note: The y-axes of the two panels differ in both range and units.

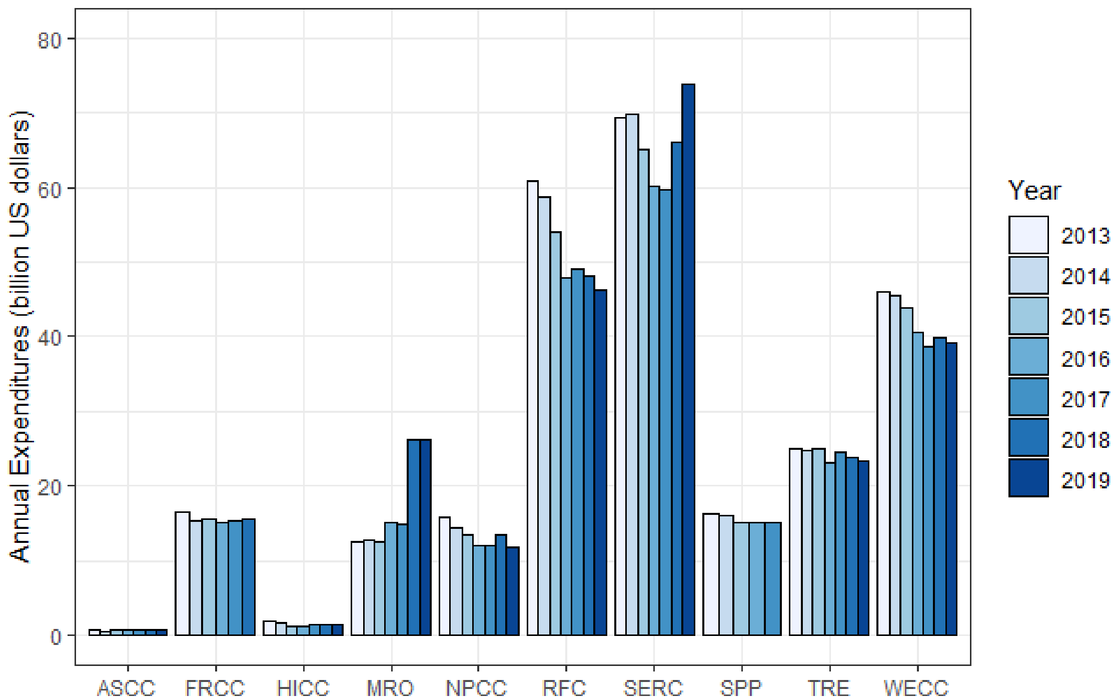
Figure 4: Annual capital, fixed O&M, variable O&M, and fuel expenditures, 2013-2019



comes primarily from large decreases in capital and fuel expenditures. Capital expenditures have decreased since 2013 in part due to the fact that capital costs of older nuclear and coal plants (greater than 30 years) are being paid off.[4] Meanwhile, the capital expenditures of new capacity additions, such as solar and wind, are relatively low. Fuel expenditures have decreased both due to the decline in coal and natural gas prices and to the decrease in fuel purchases from coal retirements. Operation and maintenance costs have remained fairly static through time.

Figure 5 shows the annual expenditure by NERC region through time. Trends vary by region, with noticeable decreases in expenditure in some regions (e.g., RFC and WECC) and increases in others (e.g., MRO). Meanwhile, expenditures in SERC decline between 2013 and 2016, and then increase after 2017. These distinct trends can be attributed to the different generation portfolios of each region.

Figure 5: Annual total expenditure by region, 2013-2019



2.4.2 Updates Since MEEDE Version 1

Several key components have been added to this updated version of the MEEDE dataset that are not available in the original 2013 version (Woollacott and Depro, 2016). First is the annual EIA time series data. While MEEDE Version 1 covers the U.S. electricity sector landscape in 2013 only,

[4] In 2019, the average unweighted age of nuclear plants was 38.4 years, coal-fired plants 40.8 years, natural gas-fired plants 25 years, oil-fired plants 32 years, and solar power plants 3.5 years.

this version includes data from 2013 to 2019. In part because of this, the overall dataset increased by over 80,000 observations.

Second, hourly-level data of NOx, SOx, and Hg are incorporated into MEEDE Version 2, where MEEDE Version 1 used data from AP-42. In this updated version, the data are presented at annual as well as 16 representative time-slice resolution to demonstrate the temporal (daily, seasonal, and yearly) variability in emissions. This addition expanded the MEEDE dataset by 36 variables per BID-PID pair per year. In terms of NOx and SOx total emissions in 2013, MEEDE Version 1 produced 1,735,868 and 3,292,037 tons, respectively. Meanwhile, MEEDE Version 2 produced 1,607,832 and 2,952,037 for each in 2013.

Though not an addition, a change in the input data in this version is the use of time series wholesale price data from FERC-714. MEEDE Version 1 relied on the Intercontinental Exchange for wholesale price data at the hub-level. In this version, we use FERC wholesale price data at the balancing authority-level and generate annual and time-slice values in dollars and dollars per MWh. This change in wholesale price data decreased the 2013 U.S. wholesale revenue from $194,206 million in MEEDE Version 1 to $120,177 million in Version 2. In MEEDE Version 1, the U.S. average annual wholesale price of electricity was $48/MWh in 2013, while in Version 2, it is $37/MWh in 2013. This difference is likely due to the inclusion of wholesale price data from regulated markets, which may be lower than in deregulated markets. MEEDE Version 1 assumes the ICE deregulated wholesale prices are representative of the national average, which may have inflated the wholesale revenue estimates.

Another change is the use of NREL's ATB generation costs in MEEDE Version 2. In Version 1, generation costs from the EIA's Electricity Market Module are used. As previously mentioned, we elected to use ATB cost information due to its higher resolution of renewable technology costs over fossil fuel technology costs. The use of the ATB created a final MEEDE dataset with fewer cost categorizations for some technologies: for instance, generation cost for biomass generators is no longer differentiated by bubbling fluidized-bed (biomass BFB) and combined cycle (biomass CC). The change in data source produced similar capital costs (in $/MW) for some technologies such as natural gas and wind. However, for others such as biomass fuels, geothermal, and solar PV, capital costs differed more significantly between the two version of MEEDE.

Finally, this updated version of MEEDE uses the MATS RTR dataset for particulate matter emissions, whereas Version 1 relies on AP-42 for this information. As previously mentioned, MATS RTR only includes filterable PM 2.5, so the 2013 total particulate matter emissions in MEEDE Version 2 will be smaller than that in MEEDE Version 1.

2.4.3 Comparison with Other Datasets

There are several other sources that provide similar plant-level data for the U.S. electricity sector. These include the EPA's National Electric Energy Data System (NEEDS), S&P Global's SNL Energy dataset, and ABB Energy Velocity Suite (formerly Ventyx). All are based on public plant-level data from multiple sources. However, the S&P Global and ABB Energy Velocity datasets are both subscription based and proprietary. As such, they are not transparent and their data builds are easily reproducible. On the other hand, while the NEEDS dataset is open-source, it is not as comprehensive as MEEDE in its representation of pollution controls or its treatment of boilers-to-generators mapping. However, the NEEDS, S&P Global, ABB Energy Velocity datasets do provide some additional information that MEEDE does not include, such as financial fillings and data from more local entities including system operators and public utility commissions. Given these differences, MEEDE is more useful for environmental analyses requiring detailed representation of power plant-level emissions, as well as studies looking for transparent data builds.

3 Application: SAM Integration

The MEEDE dataset provides a comprehensive, bottom-up depiction of the U.S. electricity sector that can provide a foundation for descriptive information, time-series analysis, and/or simulation modeling efforts. This section considers how these data can be used to inform economy-wide simulations with detailed electricity sector information. We illustrate this point by providing a flexible routine for integrating the data into a social accounting matrix (SAM) for economy-wide modeling. We find that the reference accounts require substantial changes to align with an aggregated representation of the MEEDE dataset. This finding highlights the importance of incorporating information from the bottom-up depiction of the U.S. electricity sector into CGE models.

In this section, we begin by describing the core accounting identities implicit in the construction of a social accounting matrix. In this description, we illustrate the formulation of these identities both in terms of absolute and intensive terms. Casting accounting identities using *intensities* (or shares) alleviates numerical issues with large numbers and provides flexibility in isolating recalibrated scale and intensity changes. We then formulate a mathematical program to incorporate information from MEEDE and other data sources into the SAM. We do this by minimizing the change in the data subject to constraints on accounting identities and targetted values (or priors) from MEEDE. The objective function of the mathematical program can impact the optimal change in the data. Therefore, we present two alternate assumptions common in the literature (e.g., Rutherford and Schreiber (2019)).

3.1 SAM Identities

The disaggregation routine starts with a balanced SAM based on the national accounts. We construct a SAM in three component matrices denominated in value flows: one, the value-added matrix of the factors of production for each productive sector; two, the intermediate demand matrix of the commodity demands by sector; and three, the final demand matrix of commodity demands by households, government, investment, and trade partners. For present purposes, we assume no inter-regional transfer payments. SAM balance is defined by two identities:

Row-Column Balance

$$\Sigma_f v_{rfj} + \Sigma_i x_{rij} = \Sigma_i x_{rji} + \Sigma_g d_{rjg} \qquad \forall j \tag{1}$$

Income Balance

$$\Sigma_{fj} v_{rfj} = \Sigma_g d_{rig} \qquad \forall r \tag{2}$$

where

v_{rfj}: components of the value-add matrix indexed by region (r), factor ($f = \{$capital, labor, taxes$\}$), and sector (j).
x_{rij}: components of the intermediate demand matrix indexed by region (r), supplying sector (i), and demanding sector (j).
d_{rig}: components of final demand indexed by region (r), supplying sector (i), and demand category ($g = \{C, I, G, X, M\}$).

From the SAM components, we define their intensive counterparts using value totals. Stating the mathematical program in intensive measures compresses the range of values entering the mathematical program, which can aid the numerical algorithm, normalizes the penalty for data revisions for both small and large value flows, and allows us to modify and constrain the level and intensity of economic activity separately.

Value Totals

$$Y_{rj} = \Sigma_f v_{rfj} + \Sigma_i x_{rij} \tag{3a}$$
$$Y_r = \Sigma_j Y_{rj} \tag{3b}$$
$$\mathbf{Y} = \Sigma_r Y_r \tag{3c}$$
$$D_{rg} = \Sigma_i d_{rig} \tag{3d}$$

Intensives

$$\tilde{Y}_{rj} = Y_{rj}/Y_r \tag{4a}$$
$$\tilde{D}_{rg} = D_{rg}/Y_r \tag{4b}$$
$$\tilde{Y}_r = Y_r/\mathbf{Y} \tag{4c}$$
$$\tilde{v}_{fj} = v_{fj}/Y_j \tag{4d}$$
$$\tilde{x}_{ij} = x_{ij}/Y_j \tag{4e}$$
$$\tilde{d}_{ig} = d_{ig}/D_{rg} \tag{4f}$$

We restate the SAM balance conditions in intensive variables by combining equations (1) and (2) with (3) and (4). Constraining the mathematical program with (3) and (4) imposes their definitions in intensive terms.

Row-Column Balance

$$\Sigma_f \tilde{v}_{rfj} \tilde{Y}_{rj} + \Sigma_i \tilde{x}_r ij \tilde{Y}_{rj} = \Sigma_j \tilde{x}_{rji} \tilde{Y}_{rj} + \Sigma_g \tilde{d}_{rig} \tilde{D}_{rg} \qquad \forall j \tag{5a}$$
$$\left(\Sigma_f \tfrac{v_{rfj}}{Y_{rj}} + \Sigma_i \tfrac{x_{rij}}{Y_{rj}} \right) \tfrac{Y_{rj}}{Y_r} = \Sigma_j \tilde{x}_{rji} \tfrac{Y_{ri}}{Y_r} + \Sigma_g \tilde{d}_{rig} \tfrac{D_{rg}}{Y_r} \qquad \forall j \tag{5b}$$

Income Balance

$$\Sigma_{fj}\tilde{v}_{rfj}\tilde{Y}_{rj} = \Sigma_{ig}\tilde{d}_{rig}\tilde{D}_{rg} \tag{6a}$$

$$\Sigma_{fj}\frac{v_{rfj}}{Y_{rj}}\frac{Y_{rj}}{Y_r} = \Sigma_{ig}\frac{d_{rig}}{D_{rg}}\frac{D_{rg}}{Y_r} \tag{6b}$$

Totals

$$1 = \Sigma_f\tilde{v}_{rfj} + \Sigma_i\tilde{x}_{rij} \tag{7a}$$

$$1 = \Sigma_j\tilde{Y}_{rj} \tag{7b}$$

$$1 = \Sigma_r\tilde{Y}_r \tag{7c}$$

$$1 = \Sigma_i\tilde{d}_{rig} \tag{7d}$$

Equations (5), (6), and (7) are sufficient for ensuring a balanced SAM, however, in the current formulations we have multiple interrelated SAMs, one for each region, so we must also ensure that domestic trade markets clear to fully balance the set of SAMs. To ensure domestic trade market clearance we specify

$$0 = \Sigma_r d_{rix^d} - \Sigma_r d_{rim^d} \qquad \forall i \tag{8a}$$

$$0 = \Sigma_r\left(\frac{d_{rix^d}}{D_{rx^d}}\frac{D_{rx^d}}{Y_r}Y_r - \frac{d_{rim^d}}{D_{rm^d}}\frac{D_{rm^d}}{Y_r}Y_r\right)\mathbf{Y}^{-1} \qquad \forall i \tag{8b}$$

$$0 = \Sigma_r\tilde{d}_{rix^d}\tilde{D}_{rx^d}\tilde{Y}_r - \Sigma_r\tilde{d}_{rim^d}\tilde{D}_{rx^d}\tilde{Y}_r \qquad \forall i \tag{8c}$$

where x^d denotes domestic exports and m^d domestic imports. The accounting identities (5), (6), and (7) will ensure a balanced set of regional SAMs. Balanced SAMs are necessary but often insufficient for desired model calibrations and we may elect to impose additional constraints on the mathematical program to capture information beyond the internal consistency of the SAM.

3.2 Prior Formation

MEEDE provides an alternative characterization of the costs of generating electricity. While the social accounting matrix contains a cost structure for the electricity sector, it is both typically an aggregate representation (total generation, transmission, and distribution) and may systematically differ from MEEDE given different assumptions made in its construction. Targetting values from MEEDE will produce imbalances in the fundamental accounting identities oulined above and the magnitude of those imbalances depend on our priors for what we believe to be most accurate for the sector.

We hold the accounting identities for a balanced SAM with equality as we are certain of their necessity for our modeling purposes. We may also hold information with uncertainty (i.e. priors on plausible *ranges* of values) that we would like to incorporate in our SAM balancing. We can allow values to vary only minimally from a specified prior using a penalty function that measure the deviation from our priors. Within the penalty function, we can also weight the relative penalty assigned to each component of the SAM depending on the strength of our priors. Last, we can fix or bound variables to control the extent of deviation from priors.

3.2.1 Macro Priors

Specification of prices and quantities, taxes and subsidies, transfer payments among domestic and foreign agents, and specific endowments all inform how a model is calibrated to balanced SAM data. These values may depend in part or whole on values in the SAM and we may hold priors on whether and to what extent these values should be revised. For example, we might elect to hold the national current account balance fixed, which would require further constraining the relative value of $\Sigma_r \tilde{D}_{rx^d}$ and $\Sigma_r \tilde{D}_{rm^d}$. For another example, we can hold household and/or government expenditures fixed relative to GDP to limit adjustments in implied transfer payments between them. In this illustrative exercise, however, we refrain from enforcing any macro priors to highlight the importance of priors formed specifically in the electricity sector.

3.2.2 Micro Priors, Electricity

The first step in forming our micro priors is aggregating the MEEDE data to a chosen technology and geographic resolution with only cost and revenue variables. The choice of resolution for the MEEDE aggregation is bounded by the feasibility of a solution to the disaggregation problem. Larger numbers of technologies and/or regions, particularly if combined with numerous constraints on macro priors, may inhibit the ability of the numerical solver to identify a solution and/or produce less sensible results.

The MEEDE data provide information on the costs of generating electricity whereas the social accounts characterize the broader electricity generation, transmission, and distribution sector. I.e., economic inputs from the MEEDE data represent a subset of what is included in national accounts. For this exercise, we rely on social accounts based on IMPLAN data for 2016 used in EPAs SAGE model (Marten et al., 2021). Comparing this with MEEDE, the input values for the electricity sector are mostly greater than their corresponding values in MEEDE, though there are instances where MEEDE inputs are greater, particularly for fuels whose use is predominately by generation.

We first compare IMPLAN and MEEDE input totals for consistency. Naively, the difference between the two datasets represents transmission and distribution (T&D) costs, but we have not formed priors on what T&D inputs other than labor should be, other than positive.[5] We hold capital, energy, and materials priors for T&D weakly as they are calculated as differences between generation totals and IMPLAN sector totals. For generation inputs based on MEEDE, we can be relatively more confident in the quality of the targetted values. To reflect these differences in the strength of our priors, we include a weighting parameter in our objective function that allows for penalizing deviations for certain values more than others.

The cost input categories from MEEDE are more aggregated than those from national accounts. MEEDE summarizes capital, fixed and variable O&M, and energy costs for generators. We apply

[5] In instances where the MEEDE data provide a larger value than IMPLAN data we assert a nominally positive T&D value (i.e. $1bn.)

Table 15: Micro Priors Data Sources

Input Cost	Generation Value	T&D Value
Capital	MEEDE	IMPLAN - MEEDE
Labor	QCEW	QCEW
Energy	MEEDE	IMPLAN - MEEDE (ex. coal = 0)
Materials	VOM + FOM + Fuel Margins - QCEW	IMPLAN - MEEDE

MEEDE capital costs directly to generation and the difference with IMPLAN to T&D. For labor costs, we draw on data from the Bureau of Labor Statistics (BLS) Quarterly Census of Employment and Wages (QCEW) (Bureau of Labor Statistics, 2021). The QCEW data provide labor expenditures by sector including eight technology types of electricity generation.[6] We rely on these data to form a prior for T&D and generation labor inputs, which we deduct from O&M costs for generation. To assign the labor data to generation technologies, we map our target technology resolution to that provided in the QCEW data. Where the target technology resolution exceeds QCEW (i.e. our QCEW to target mapping is one-to-many), we distribute total QCEW labor using MEEDE's fixed O&M costs for the target technologies.

MEEDE fuel costs are reported as delivered from EIA Form 923. We assign MEEDE fuel costs less delivery margins to generation technologies and the margin value to the materials total. IMPLAN data provide wholesale fuel costs and report delivery margin costs separately, leaving IMPLAN fuel costs less wholesale generation fuel costs to form our T&D prior except for coal, which we assign to zero for T&D. O&M costs also add to materials total. With labor costs deducted from MEEDE O&M, the remaining costs sum to materials. Last, we distribute total materials by the materials input pattern in the IMPLAN electricity sector.

3.3 Balancing Routine

We impose our priors on a 23 sector, 4 region (North, South, Mid, and West) SAM from Marten et al. (2021). We disaggregate the electricity sector to eight generation technologies and one T&D sector. The set of priors we impose on the SAM data will be inconsistent with the SAM balance identities in Section 3.1. Imbalances range from -39% to -15% of output across sectors nationally and range wider regionally.

To resolve the imbalances we introduced by asserting our priors, we pose a mathematical program to minimally revise the unbalanced SAM, conserving the information we provide, subject to meeting the accounting identities for SAM balance. We minimize the extent of revision using a penalty function that measures the distance between the candidate SAM, $\mathbb{S}^u$, and a balanced SAM solution, $\mathbb{S}^b$. Table 16 states the mathematical program we implement to balance the SAM.

We implement the mathematical program in GAMS using the PATHNLP solver. The least squares and Kullback-Leibler divergence functions, both solved as NLPs, provide comparable results. We present the results of the SAM balancing on the electricity sector in Table 17. Revisions from our priors are very close to the candidate values and identical in share terms as generation input and output shares were fixed in the program. Economy-wide sectoral output changes ranged from -26% to 4% nationally for the least squares metric and -26% to 6% for the KL Divergence.

[6] The technologies include hydroelectric, fossil fuels, nuclear, solar, wind, geothermal, biomass, and other.

Table 16: Mathematical program for balancing an unbalanced SAM

Given:	$\mathbb{S}^u = \{\tilde{v}^u_{fj}, \tilde{x}^u_{ij}, \tilde{Y}^u_{rj}, \tilde{d}^u_{ig}, \tilde{D}^u_{rg}, \tilde{Y}^u_r\}$	Candidate intensive values
Find:	$\mathbb{S}^b = \{\tilde{v}^b_{fj}, \tilde{x}^b_{ij}, \tilde{Y}^b_{rj}, \tilde{d}^b_{ig}, \tilde{D}^b_{rg}, \tilde{Y}^b_r\}$	Corresponding solution values
Minimizing:	$\Sigma_{v,x,y,d}(\mathbb{S}^u - \mathbb{S}^b)^2$	Sum of squared deviations
	$\Sigma_{v,x,y,d}\mathbb{S}^u \ln(\mathbb{S}^b/\mathbb{S}^u)^2$	Kullback-Leibler Divergence
Subject to:	Equation 5	Row-column balance
	Equation 6	Income balance
	Equation 7	Totals
	Equation 8	Trade balance

The balancing routine is flexibly programmed to admit different technology and regional aggregations or to be run on different years. Additional macro-economic constraints or bounding of variables could further limit large or important differences between candidate and solution values. Such refinements are helpful way to address outliers such as the increases in the T&D sector where we may carry some prior on “reasonable” solution levels.

Table 17: Electricity costs (2019$ Billion) prior and post balancing routine using the least-squares metric

GT&D	Data	Capital	Labor	Energy	Materials	Output
T&D	Prior	19.2	26.4	0	447.7	752.4
	Solution	21.1	25.3	19	656.3	945.2
Coal	Prior	32.1	5.3	23.7	34.6	95.7
	Solution	28.6	5.1	21.4	31.3	86.4
Gas	Prior	32.6	3	30.1	18.5	84.2
	Solution	29.5	2.9	26.9	16.6	76
Hydro	Prior	2.6	1.8	0	5.5	9.9
	Solution	2.6	1.6	0	5.7	9.9
Nuclear	Prior	18.6	2	0	13.8	34.5
	Solution	17.7	2.2	0	13.2	33.1
Oil	Prior	2.4	0.4	1.3	1.8	6
	Solution	2.1	0.5	1.3	1.7	5.5
Other	Prior	5.8	0.3	0	3.8	9.8
	Solution	5.4	0.3	0	3.4	9
Solar	Prior	3.8	0.3	0	0.3	4.4
	Solution	3.6	0.3	0	0.3	4.2
Wind	Prior	12.1	0.4	0	3.5	16
	Solution	11.6	0.4	0	3.4	15.3

4 Conclusion

In this report, we introduced MEEDE Version 2 and the process by which the dataset was constructed. MEEDE relies on a combination of publicly-available data sources from the EPA, EIA, FERC, and NREL. We illustrate MEEDE's engineering, economic, and environmental outputs for the most recent year of data, 2019. We discuss some of the advantages and limitations of MEEDE and its underlying data. The primary advantages of MEEDE include its transparency, public availability, and comprehensive unit-level characterization of utility-scale generation in the United States. We demonstrate how MEEDE data (or other bottom-up sources) can be successfully integrated into national accounts for use in economy-wide modeling by way of a matrix balancing routine with differing objective functions. While not described here, the dataset has also been used in partial equilibrium modeling of the electricity sector. For access to the MEEDE dataset, please contact the corresponding author.

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A Appendix I: MEEDE Data Dictionary

Variable	Label	Aggregation Level
ash_cont	[BLR]: Pct by wt. ash content [EIA.923_P3]	Boiler
bal_auth	[PLNT]: Plant Balancing Authority [EIA.860-Plant]	Plant
BID	[BLR]: Boiler Identifier [EIA.923_P3]	Boiler
blr_btm	[BLR]: Type of boiler bottom (Wet or Dry) [EIA.860_Eqp]	Boiler
blr_btu	[BLR]: Qty of fuel consumed in MMBTU [EIA.923_P3]	Boiler
blr_btu_ele	[BLR]: MMBTU cons. by boiler for ele gen [EIA.923_P1+P3]	Boiler
blr_btu_tot	[BLR]: MMBTU total for all boilers @PID-PM-FT [EIA.923_P3]	Boiler
blr_ct	[BLR]: No. boilers @PID-PM-FT [EIA.923_P3]	Boiler
blr_fire_typ	[BLR]: Type of firing of boiler [EIA.860_Eqp]	Boiler
blr_na	[BLR]: No data available @PID-PM-FT-BID [EIA.923_P3]	Boiler
blr_netgen	[BLR]: Net gen MWh as apportioned to boiler [EIA.923_P1-P3]	Boiler
blr_netgen_stup	[BLR]: Net generation (MWh) attributable to startup fuel by BTUs [EIA.923]	Boiler
blr_netgen_tot	[BLR]: Net generation (MWh) total = startup + regular [EIA.923]	Boiler
blr_newsrc	[BLR]: Subject to new source review standards [EIA.860_Eqp]	Boiler
blr_noact	[BLR]: No activity data available [EIA.923_P3]	Boiler
blr_noattr	[BLR]: No attribute data available [EIA.860]	Boiler
blr_qty	[BLR]: Qty of fuel consumed in phys. units [EIA.923_P3]	Boiler
blr_qty_ele	[BLR]: Fuel phys unit cons. by boiler for ele gen [EIA.923_P1+P3]	Boiler
blr_svc_yr	[BLR]: Service year of boiler [EIA.860_Eqp]	Boiler
CAMD_GLOAD_sum_CO2	[PLNT]: Total GLOAD (MWh) of CO2 [CAMD]	Plant
CAMD_GLOAD_sum_NOX	[PLNT]: Total GLOAD (MWh) of NOX [CAMD]	Plant
CAMD_GLOAD_sum_SOX	[PLNT]: Total GLOAD (MWh) of SOX [CAMD]	Plant
CAMD_heatinput_sum_CO2	[PLNT]: Heat input (mmBtu) of CO2 [CAMD]	Plant
CAMD_heatinput_sum_NOX	[PLNT]: Heat input (mmBtu) of NOX [CAMD]	Plant
CAMD_heatinput_sum_SOX	[PLNT]: Heat input (mmBtu) of SOX [CAMD]	Plant
CAMD_tons_med_CO2	[BLR]: Median CAMD emissions of CO2 in tons [CAMD-AP42]	Boiler
CAMD_tons_med_NOX	[BLR]: Median CAMD emissions of NOX in tons [CAMD-AP42]	Boiler
CAMD_tons_med_SOX	[BLR]: Median CAMD emissions of SOX in tons [CAMD-AP42]	Boiler
CAMD_tons_p25_CO2	[BLR]: 25th percentile CAMD emissions of CO2 in tons [CAMD-AP42]	Boiler
CAMD_tons_p25_NOX	[BLR]: 25th percentile CAMD emissions of NOX in tons [CAMD-AP42]	Boiler
CAMD_tons_p25_SOX	[BLR]: 25th percentile CAMD emissions of SOX in tons [CAMD-AP42]	Boiler

CAMD_tons_ p75_CO2	[BLR]: 75th percentile CAMD emissions of CO2 in tons [CAMD-AP42]	Boiler
CAMD_tons_ p75_NOX	[BLR]: 75th percentile CAMD emissions of NOX in tons [CAMD-AP42]	Boiler
CAMD_tons_ p75_SOX	[BLR]: 75th percentile CAMD emissions of SOX in tons [CAMD-AP42]	Boiler
CAMD_tons_ sum_CO2	[BLR]: Total CAMD emissions of CO2 in tons [CAMD-AP42]	Boiler
CAMD_tons_ sum_NOX	[BLR]: Total CAMD emissions of NOX in tons [CAMD-AP42]	Boiler
CAMD_tons_ sum_SOX	[BLR]: Total CAMD emissions of SOX in tons [CAMD-AP42]	Boiler
census	[PLNT]: Census region code [923.P1]	Plant
CHP	[PLNT]: Combined heat & power plant [EIA.923_P1]	Plant
county	[PLNT]: Plant county location [EIA.860-Plant]	Plant
ctrl_typ_HG	[BLR]: Type of HG ctrl. from IPM cost data [IPM_Ch5]	Boiler
ctrl_typ_NOX	[BLR]: Type of NOx ctrl. from IPM cost data [IPM_Ch5]	Boiler
ctrl_typ_PM	[BLR]: Type of PM ctrl. from IPM cost data [IPM_Ch5]	Boiler
ctrl_typ_SOX	[BLR]: Type of SOx ctrl. from IPM cost data [IPM_Ch5]	Boiler
emissions_typ	Type of emissions corresponding to this row of data	
FC	[BLR]: Fuel Code-Map based on EIA Fuel Types	Boiler
FC_st	[BLR]: Fuel Code-Map based on EIA Fuel Types of start-ups	Boiler
FERC_annual	[PLNT]: Total wholesale ELE price in $/MWh [FERC.714]	Plant
FLU_height	[BLR]: Wtd. avg. height of flue(s) serving boiler in ft [EIA.860_Equip-Flue]	Boiler
FOM_gen	[BLR]: Total boiler-level fixed O&M cost of generation ($)	Boiler
FOM_HG	[BLR]: Total boiler-level fixed O&M cost of HG ctrl ($)	Boiler
FOM_NOX	[BLR]: Total boiler-level fixed O&M cost of generation ($)	Boiler
FOM_PM	[BLR]: Total boiler-level fixed O&M cost of PM ctrl ($)	Boiler
FOM_SOX	[BLR]: Total boiler-level fixed O&M cost of SOX ctrl ($)	Boiler
FOM_tot	[BLR]: Total boiler-level fixed O&M cost of generation & control ($)	Boiler
FT	[BLR]: Fuel Type [EIA.923_P1-P3]	Boiler
FT_st	[BLR]: Fuel Type of start-up fuel	Boiler
FUE_cost	[BLR]: Boiler-level fuel cost of generation (ex. startup) ($)	Boiler
FUE_cost_st	[BLR]: Total boiler-level startup fuel cost of generation ($)	Boiler
FUE_tot	[BLR]: Total boiler-level fuel cost of generation & startup ($)	Boiler
fuel_pxbtu	[BLR]: Fuel price ($/MMbtu) [EIA.923_P5]	Boiler
fuel_pxbtu_st	[BLR]: Fuel price of startup fuel ($/MMbtu) [EIA.923_P5]	Boiler
GEN_cst	[BLR]: Total boiler-level cost of generation & control ($)	Boiler
GEN_rev_annual	[PLNT]: Total revenue ($)	Plant
gen_svc_yr	[GEN]: NP-weighted average service year @PID-PM [EIA.860_Gen]	Generator
GHG_tons_ med_CH4	[BLR]: Median GHGRP emissions CH4 in tons [GHGRP-AP42]	Boiler
GHG_tons_ med_CO2	[BLR]: Median GHGRP emissions CO2 in tons [GHGRP-AP42]	Boiler
GHG_tons_ med_N2O	[BLR]: Median GHGRP emissions N2O in tons [GHGRP-AP42]	Boiler
GHG_tons_ p25_CH4	[BLR]: 25th percentile GHGRP emissions CH4 in tons [GHGRP-AP42]	Boiler

GHG_tons_ p25_CO2	[BLR]: 25th percentile GHGRP emissions CO2 in tons [GHGRP-AP42]	Boiler
GHG_tons_ p25_N2O	[BLR]: 25th percentile GHGRP emissions N2O in tons [GHGRP-AP42]	Boiler
GHG_tons_ p75_CH4	[BLR]: 75th percentile GHGRP emissions CH4 in tons [GHGRP-AP42]	Boiler
GHG_tons_ p75_CO2	[BLR]: 75th percentile GHGRP emissions CO2 in tons [GHGRP-AP42]	Boiler
GHG_tons_ p75_N2O	[BLR]: 75th percentile GHGRP emissions N2O in tons [GHGRP-AP42]	Boiler
GHG_tons_ sum_CH4	[BLR]: Total GHGRP emissions CH4 in tons [GHGRP-AP42]	Boiler
GHG_tons_ sum_CO2	[BLR]: Total GHGRP emissions CO2 in tons [GHGRP-AP42]	Boiler
GHG_tons_ sum_N2O	[BLR]: Total GHGRP emissions N2O in tons [GHGRP-AP42]	Boiler
heat_rt	[GEN]: Heat rate (MMBtu / MW) @PID-PT [EIA.923]	Generator
heat_rt_cat	[PLNT]: Heat rate category for cost data [EIA.923]	Plant
HG_erf	[BLR]: Emissions ctrl reduction factor for HG [AP42]	Boiler
HG_tons_med_HG	[BLR]: Median MATS-HG emissions in tons [MATS-HG-AP42]	Boiler
HG_tons_p25_HG	[BLR]: 25th percentile MATS-HG emissions in tons [MATS-HG-AP42]	Boiler
HG_tons_p75_HG	[BLR]: 75th percentile MATS-HG emissions in tons [MATS-HG-AP42]	Boiler
HG_tons_sum_HG	[BLR]: Total MATS-HG emissions in tons [MATS-HG-AP42]	Boiler
K_gen	[BLR]: Total boiler-level capital cost of generation ($)	Boiler
K_HG	[BLR]: Total boiler-level capital cost of HG ctrl ($)	Boiler
K_NOX	[BLR]: Total boiler-level capital cost of NOX ctrl ($)	Boiler
K_PM	[BLR]: Total boiler-level capital cost of PM ctrl ($)	Boiler
K_SOX	[BLR]: Total boiler-level capital cost of SOX ctrl ($)	Boiler
K_tot	[BLR]: Total boiler-level captial cost of generation & control ($)	Boiler
lat	[PLNT]: Plant latitude [EIA.860-Plant]	Plant
long	[PLNT]: Plant longitude [EIA.860-Plant]	Plant
NERC	[PLNT]: Plant NERC region code [EIA.860-Plant]	Plant
netgen	[PLNT]: Net gen (MWh) @PID-PM-FT [EIA.923_P1]	Plant
NOX_erf	[BLR]: Emissions ctrl reduction factor for NOx [AP42]	Boiler
NP	[GEN]: Nameplate capacity (MW) [EIA.860_Gen]	Generator
NP_cat	[PLNT]: Nameplate category for cost data [EIA.923]	Plant
NP_plant	[PLNT]: Nameplate capacity of entire plant (MW) [EIA.860_Gen]	Plant
phys_unit_FT	[BLR]: Physical Unit of fuel [EIA.923_P3]	Boiler
PID	[PLNT]: Plant Identifier [EIA.923_P3]	Plant
plant_nm	[PLNT]: Plant name[EIA.860_Plant]	Plant
plnt_noact	[PLNT]: No data available @PID-PM-FT [EIA.923_P1]	Plant
plnt_svc_yr	[GEN]: NP-weighted average service year @PID [EIA.860_Gen]	Generator
PM	[GEN]: Prime Mover [EIA923_P1-P3]	Generator
PM_erf	[BLR]: Emissions ctrl reduction factor for PM [AP42]	Boiler
PM_tons_sum_PM	[BLR]: Total MATS-PM emissions in tons [MATS-PM-AP42]	Boiler
PT	[PLNT]: Generation type categorized to ATB cost data	Plant
PT_btu_ele	[GEN]: Net fuel consumption for generation (MMBtus) @PID-PT [EIA.923]	Generator
PT_netgen	[GEN]: Net generation (MWh) @PID-PT [EIA.923]	Generator

PT_NP	[PT]: Nameplate capacity (MW) @PID-PT	Plant Type
reg_stat	[PLNT]: Plant regulatory status [EIA.860-Plant]	Plant
RMV_eff_NOX	[GEN]: Control percent removal efficiency [IPM_Ch5]	Generator
RMV_eff_SOX	[GEN]: Control percent removal efficiency [IPM_Ch5]	Generator
SOX_erf	[BLR]: Emissions ctrl reduction factor for SOx [AP42]	Boiler
state	[PLNT]: State where plant is located	Plant
sulf_cont	[BLR]: Pct by wt. SO2 content [EIA.923_P3]	Boiler
tot_btu	[PLNT]: Total MMBTU cons. @PID-PM-FT [EIA.923_P1]	Plant
tot_btu_ele	[PLNT]: ELE gen MMBTU cons. @PID-PM-FT [EIA.923_P1]	Plant
tot_qty_ele	[PLNT]: ELE gen phys unit cons. @PID-PM-FT [EIA.923_P1]	Plant
VOM_gen	[BLR]: Total boiler-level var. O&M cost of generation ($)	Boiler
VOM_HG	[BLR]: Total boiler-level var. O&M cost of HG ctrl ($)	Boiler
VOM_NOX	[BLR]: Total boiler-level var. O&M cost of NOX ctrl ($)	Boiler
VOM_PM	[BLR]: Total boiler-level var. O&M cost of PM ctrl ($)	Boiler
VOM_SOX	[BLR]: Total boiler-level var. O&M cost of SOX ctrl ($)	Boiler
VOM_tot	[BLR]: Total boiler-level var. O&M cost of generation & control ($)	Boiler
year	Year [EIA.923_P5]	Dataset
zip	[PLNT]: Plant zipcode [EIA.860-Plant]	Plant

B MEEDE Version 2 Outputs for 2016

Table A1: Annual net electricity generation from EIA Form 923 by prime mover and NERC region, 2016 (in millions of MWh)

		Annual Net Generation (Millions of MWh)										
Code	**Description**	**SERC**	**RFC**	**WECC**	**TRE**	**MRO**	**SPP**	**NPCC**	**FRCC**	**HICC**	**ASCC**	**Total USA**
ST	Steam Turbine	701	668	260	152	148	119	104	84	6	1	2,244
CT	Combined Cycle (Combustion)	204	123	119	104	9	36	51	89	2	2	738
HY	Hydraulic Turbine	32	9	174	1	12	6	33	0	0	2	268
CA	Combined Cycle (Steam)	108	64	63	47	5	21	26	48	1	0	383
WT	Wind (Onshore)	4	24	51	53	45	42	7	0	1	0	227
GT	Gas Turbine	42	27	22	15	3	6	6	7	0	1	130
PV	Photovoltaic	4	1	25	1	0	0	1	0	0	0	33
CS	Combined Cycle (Single)	1	6	9	10	0	1	14	1	0	0	41
BT	Binary Cycle Turbines	0	0	4	0	0	0	0	0	0	0	4
IC	Internal Combustion (Diesel)	2	3	3	1	1	1	1	0	0	1	14
CP	Concentrated Solar (Storage)	0	0	1	0	0	0	0	0	0	0	1
OT	Other	0	0	0	0	0	0	0	0	0	0	1
FC	Fuel Cell	0	0	0	0	0	0	0	0	0	0	1
PS	Pumped Storage	-4	-2	0	0	0	0	-1	0	0	0	-7
FW	Energy Storage (Flywheel)	0	0	0	0	0	0	0	0	0	0	0
WS	Wind (Offshore)	0	0	0	0	0	0	0	0	0	0	0
BA	Battery	0	0	0	0	0	0	0	0	0	0	0
CE	Compressed Air (Storage)	0	0	0	0	0	0	0	0	0	0	0
Total		**1,095**	**924**	**731**	**384**	**222**	**231**	**242**	**229**	**10**	**6**	**4,076**

Regions: ASCC = Alaska Systems Coordinating Council; HICC = Hawaiian Islands Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.
Note: The values shown here may not sum to the totals shown due to independent rounding.

Table A2: Meta-summary of EIA Form 923 data, 2016

Form	Schedule	Page	Observation	Variables	Number of Plants	Number of Observations
923	2_3_4_5_M_12	Page 1: Generation and Fuel Data	{PID, PM, FT}	< Fuel, Generation >	8,120	12,787
923	2_3_4_5_M_12	Page 3: Boiler Fuel Data	{PID, PM, FT, BID}	< Fuel, Sulfur Content, Ash Content >	1,543	9,925
923	2_3_4_5_M_12	Page 5: Fuel Receipts and Costs	{PID}	< Monthly Fuel Prices >	1,046	30,751
860	3.1	Operable	{ PID, GID, PM, FT }	< Nameplate Capacity, Operating Year, Planned Retirement Year >	8,084	20,724
860	2	Plant	{ PID }	< Plant Attributes >	9,711	9,711
860	6.1	Boiler-Generator	{ PID, GID, BID }	< PID, GID, BID >	1,698	7,426
860	6.2	Boiler Info & Design Parameters	{ PID, BID }	< PID, BID, In-service Year, Firing Type, Wet/Dry Bottom Tech >	1,700	4,732
860	6.1	Boiler Particulate Matter	{ PID, BID, FGP_ID }	< PID, ID, FGP_ID >	868	2,476
860	6.1	Boiler SO2	{ PID, BID, FGD_ID }	< PID, BID, FGD_ID >	445	991
860	6.1	Boiler NOX	{ PID, BID, NOX_ID }	< PID, BID, NOX_ID >	773	1,671
860	6.1	Boiler Mercury	{ PID, BID, HG_ID }	< PID, BID, HG_ID >	500	1,469
860	6.1	Emissions Control Equipment	{ PID, FGP_ID, FGD_ID, NOX_ID, HG_ID, Equipment Type, Controls }	< Control ID (PM, SOX, NOX, HG), Equipment Type >	1,204	5,830
860	6.2	Emission Standards & Strategies	{ PID, BID }	< PID, BID, Control Strategies: SOX, NOX, HG >	1,700	4,732
860	6.1	Boiler Stack Flue	{ PID, BID, FID }	< PID, BID, FID >	873	2,936
860	6.2	Stack Flue	{ PID, FID }	< PID, FID, Service Year, Height, Volume, Status >	876	2,382

Abbreviations: BID = boiler ID; FGD_ID = flue gas desulfurization equipment ID; FGP_ID = flue gas particulate collector ID; FT = fuel type; GID = generator ID; HG_ID = mercury equipment ID; NOX_ID = nitrogen oxide equipment ID; PID = plant ID; PM = prime mover; SOX_ID = sulfur oxide equipment ID.

Table A3: U.S. electric grid fuel heat, sulfur, and ash content, 2016

Fuel Code			Pollutant Content (%)			Volume/Mass	
	Fuel Code	Description	Sulfur	Ash	BTU (Quadrillion)	Quantity	Units
Coal	BIT	Bituminous coal	2.29	10.79	5.01	225.51	MM Sh. Ton
Coal	SUB	Subbituminous coal	0.35	5.95	4.85	285.46	MM Sh. Ton
Coal	COL	Other coal	1.11 0.00	11.64 0.00	3.12	183.49 109.80	MM Sh. Ton Bn. Cu. Ft.
Gas	GAS	Natural gas & propane	0.00	0.00	10.51	9,825.88	Bn. Cu. Ft.
Gas	OGS	Other gases	0.00	0.00	0.26	1,162.26	Bn. Cu. Ft.
Oil	OIL	Oil & petroleum deriv.	0.58 5.24	0.00 0.74	0.25	20.06 17.21	MM Barrels MM Sh. Ton
Other	BML	Biomass liquids	0.00	0.00	0.00	4.46	MM Barrels
Other	BMS	Biomass solids	0.00	0.00	0.38	124.83	MM Sh. Ton
Other	MSW	Municipal solid wastes	0.00	0.00	0.28	30.85	MM Sh. Ton
Other	OTH	Miscellaneous other	0.00	0.00	0.02	9.35	MM Sh. Ton

Table A4: Percent of net MWh fossil fuel generation with environmental controls per region, 2016 (%)

Control Equipment Type	Control ID	ASCC	FRCC	HICC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Total USA
Sulfur Control Technologies		**5.4**	**19.3**	**18.1**	**71.8**	**3.2**	**54.6**	**37.7**	**36.3**	**26.8**	**41.8**	**39.7**
Circulating dry scrubber	CD	0.0	0.3	0.0	7.8	0.5	1.7	0.1	3.8	1.5	0.9	1.4
Dry sorbent (powder) injection type (DSI)	DSI	5.4	2.2	17.9	7.1	0.0	7.4	8.9	3.6	0.9	0.9	5.2
Jet bubbling reactor (wet) scrubber	JB	0.0	0.0	0.0	0.0	0.0	6.0	4.1	0.0	0.0	0.0	2.5
Mechanically aided type (wet) scrubber	MA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Packed type (wet) scrubber	PA	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.1
Spray dryer type / dry FGD / semi-dry FGD	SD	0.0	2.0	0.0	37.6	1.1	2.2	3.8	8.3	1.5	11.4	6.0
Spray type (wet) scrubber	SP	1.0	9.9	0.0	19.3	1.5	35.3	25.4	22.6	21.9	19.4	23.6
Tray type (wet) scrubber	TR	0.0	7.0	0.0	0.0	0.0	10.4	2.0	0.0	1.9	5.9	4.5
Venturi type (wet) scrubber	VE	0.0	0.0	0.1	5.1	0.1	1.1	1.0	2.6	0.0	3.4	1.5
Particulate Control Technologies		**16.4**	**21.4**	**18.0**	**80.4**	**7.4**	**59.2**	**48.3**	**53.9**	**35.4**	**39.4**	**46.2**
Baghouse (fabric filter), pulse	BP	12.1	2.0	0.0	40.2	2.0	8.5	13.6	25.6	10.5	13.8	12.9
Baghouse (fabric filter), reverse air	BR	4.3	0.3	18.0	15.9	0.0	1.1	2.8	4.2	8.5	11.5	4.8
Baghouse (fabric filter), shake and deflate	BS	0.0	0.0	0.0	1.8	0.0	0.1	0.0	3.7	0.9	0.1	0.5
Electrostatic precipitator, cold side, with flue gas conditioning	EC	0.0	3.7	0.0	14.3	0.1	12.2	10.3	3.4	8.7	2.7	8.2
Electrostatic precipitator, hot side, with flue gas conditioning	EH	0.0	0.1	0.0	4.4	0.4	0.5	0.5	1.1	0.0	0.0	0.6
Electrostatic precipitator, cold side, without flue gas conditioning	EK	0.0	14.5	0.0	21.9	6.1	38.0	27.7	18.3	10.4	5.2	21.9
Electrostatic precipitator, hot side, without flue gas conditioning	EW	0.0	0.4	0.0	5.4	0.6	3.0	4.4	3.5	0.0	7.6	3.6
Multiple cyclone	MC	6.3	0.6	0.0	0.8	0.4	0.1	1.9	2.8	0.0	0.7	0.9
Single cyclone	SC	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Nitrogen Control Technologies		**9.5**	**27.7**	**18.0**	**86.5**	**31.5**	**69.0**	**63.3**	**68.7**	**51.3**	**55.9**	**59.6**
Advanced overfire air*	AA	0.0	0.0	0.0	22.3	1.5	0.4	1.1	3.1	3.4	11.5	3.9
Biased firing*	BF	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.1	0.0	0.1
Fluidized bed combustor*	CF	0.0	4.3	17.9	1.8	0.1	1.6	1.3	4.1	2.6	0.4	1.8
Flue recirculation*	FR	0.0	0.1	0.0	0.1	1.0	0.5	1.3	1.5	0.7	0.5	0.8
Fuel reburning*	FU	0.0	0.6	0.0	0.0	0.3	0.0	0.5	0.0	0.0	0.1	0.2
Water injection*	H2O	4.0	0.0	0.0	0.2	2.5	0.3	0.5	0.1	0.2	0.1	0.4
Low excess air*	LA	1.0	0.0	0.0	0.6	1.8	0.1	1.8	1.2	1.7	0.7	1.0
Low NOx burner*	LN	4.3	16.4	0.0	70.5	14.8	42.3	36.4	52.8	39.7	41.7	39.1
Ammonia injection*	NH3	0.0	0.0	0.0	1.1	3.7	6.0	2.1	5.3	5.7	8.0	4.3
Overfire air*	OV	4.3	9.5	0.0	52.8	9.9	24.6	23.1	48.3	21.5	19.1	24.1
Selective noncatalytic reduction	SN	0.0	2.5	18.0	13.7	0.5	5.9	4.4	9.9	3.4	1.5	4.7
Selective catalytic reduction	SR	0.2	21.0	0.0	21.2	19.0	53.8	44.8	26.2	22.4	20.4	35.4
Steam injection*	STM	0.0	0.0	0.0	0.0	0.3	0.2	0.2	0.0	0.3	0.3	0.2
Mercury Control Technologies		**0.0**	**1.6**	**0.0**	**69.3**	**2.0**	**14.5**	**27.6**	**48.6**	**34.8**	**29.7**	**26.0**
Activated carbon injection system	ACI	0.0	1.6	0.0	69.3	1.9	14.2	26.7	48.6	34.8	29.7	25.7
Lime injection*	LIJ	0.0	0.0	0.0	0.0	0.1	0.6	1.7	6.8	0.0	0.0	1.1
Other	**OT**	**0.0**	**0.0**	**0.0**	**11.0**	**0.0**	**1.6**	**2.5**	**0.1**	**0.6**	**8.0**	**2.9**
Total fossil fuel generation (Millions of MWh)		**3.6**	**194.3**	**8.4**	**134.9**	**117.1**	**608.8**	**750.1**	**172.4**	**286.4**	**395.0**	**2,671.0**

Note: Change-in-process technologies are marked with an asterisk.

Table A5: Costs of generation and pollution control, 2016

Installation Attribute		Total Costs Excluding Fuel (MM 2019$)			
Cost Component	**Net Generation (in thousands of MWh)**	**Capital**	**Fixed O&M**	**Variable O&M**	**Total**
Total system, excluding fuel	**4,075,533**	**90,651**	**57,733**	**17,343**	**165,727**
Generation only	**4,075,533**	**85,382**	**54,082**	**9,920**	**149,384**
Controls	**1,648,818**	**5,270**	**3,650**	**7,423**	**16,343**
SOX Controls	**1,086,353**	**2,378**	**2,765**	**4,145**	**9,288**
Limestone forced oxidation scrubber	810,689	1,159	2,073	3,036	6,268
Lime spray dryer scrubber	274,000	1,490	899	1,087	3,477
Dry sorbent injection	141,601	403	357	1,296	2,056
PM Controls	**1,282,767**	**1,548**	**426**	**102**	**2,076**
Electrostatic precipitator (cold side)	817,015	463	273	66	802
Fabric filter baghouse	501,983	1,193	192	47	1,432
Electrostatic precipitator (cold side), with flue gas conditioning	221,310	139	72	18	228
Electrostatic precipitator (hot side)	129,977	273	59	13	345
Electrostatic precipitator (hot side), with flue gas	18,137	84	15	2	102
NOX Controls	**1,593,788**	**1,301**	**436**	**1,385**	**3,121**
Selective catalytic reduction	948,573	1,171	318	1,185	2,675
Low-NOx burner (wall fired)	732,258	945	263	841	2,048
Low-NOx burner with advanced overfire air (tangentially fired)	371,190	44	56	8	109
Low-NOx burner with overfire air (wall fired)	282,972	585	135	453	1,173
Selective noncatalytic reduction (fluidized bed)	28,083	26	4	81	111
Vertically fired	4,360	15	1	7	23
HG Control - Active Carbon Injection	**707,979**	**43**	**23**	**1,792**	**1,858**

Abbreviations: Hg = mercury; MWh = megawatt-hour; NOX = nitrogen oxide; O&M = operations and maintenance; PM = particulate matter; SOX = sulfur oxide.
Notes: Total system cost = cost of generation plus cost of controls. Amounts do not sum across controls because many installations run multiple controls (e.g., selective catalytic reduction with a low-NOx wall-fired burner). Capital costs are amortized.

Table A6: Capital and O&M costs across EIA power plants for select prime movers, 2016

Installation Attribute			Total Costs Including Pollution Control Technologies (MM 2019$)		
Prime Mover Type	**Code**	**Net Generation (Millions of MWh)**	**Capital Cost**	**Fixed O&M Cost**	**Variable O&M Cost**
Combined Cycle (Steam)	CA	383.10	1,583	260	896
Combined Cycle (Single)	CS	40.63	813	149	90
Combined Cycle (Combustion)	CT	738.36	18,944	3,287	1,651
Gas Turbine	GT	130.03	10,194	2,122	622
Hydraulic Turbine	HY	267.81	2,462	7,306	0
Internal Combustion (Diesel)	IC	13.52	528	135	66
Photovoltaic	PV	32.56	2,382	407	0
Steam Turbine	ST	2,243.54	41,088	39,985	14,015
Wind (Onshore)	WT	226.92	12,035	3,896	0

Table A7: Total generation cost by plant type and region, 2016

	Generation Costs (MM 2019$)									
ATB Technology	**MRO**	**NPCC**	**RFC**	**SERC**	**SPP**	**TRE**	**WECC**	**ASCC**	**HICC**	**Total USA**
Advanced Nuclear	511	2,149	9,321	9,512	187	3,574	3,458	0	0	28,525
Advanced Supercritical Coal Avg CF	3,017	1,162	6,187	7,255	2,828	1,963	3,513	113	773	23,983
Advanced Supercritical Coal High CF	5,890	1,048	16,411	19,419	5,344	5,562	5,932	0	0	54,261
Biomass	518	596	842	2,633	218	86	733	0	58	5,464
Coal IGCC Avg CF	0	0	459	0	0	0	0	0	0	459
Concentrated Solar Power	0	0	0	0	0	0	880	0	0	880
Geothermal – Binary	0	0	0	0	0	0	709	0	14	723
Geothermal – Dual Flash	0	0	0	0	0	0	931	0	23	954
Hydropower New Stream-Reach Development	365	825	474	1,698	222	62	5,924	162	9	9,518
Natural Gas Combined Cycle Avg CF	827	4,210	6,010	9,447	2,360	4,772	8,755	209	226	34,456
Natural Gas Combined Cycle High CF	7	368	1,896	3,907	213	2,205	1,322	0	0	9,704
Natural Gas Combustion Turbine Avg CF	1,012	788	4,154	5,466	989	1,055	2,570	244	62	15,350
Offshore Wind	0	16	0	0	0	0	0	0	0	16
Onshore Wind	2,983	617	1,860	322	2,608	3,705	3,785	12	40	13,324
Solar Photovoltaic	17	96	159	497	27	81	1,945	0	7	2,802

Abbreviations: Avg CF = average capacity factor; High CF = high capacity factor; IGCC = integrated gasification combined cycle.
Regions: ASCC = Alaska Systems Coordinating Council; HICC = Hawaiian Islands Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.

Table A8: Wholesale revenue and total costs by NERC region, 2016

	MM 2019$					
NERC Region	**Wholesale Revenue**	**Fuel Costs**	**Capital Costs**	**Fixed O&M Costs**	**Variable O&M Costs**	**Total Costs**
ASCC	373	335	300	88	17	740
FRCC	4,849	6,007	5,646	2,608	817	15,077
HICC	691	629	442	128	45	1,244
MRO	5,710	2,547	7,781	3,645	1,183	15,156
NPCC	6,444	3,169	4,326	3,914	557	11,967
RFC	26,638	14,324	15,699	13,260	4,560	47,843
SERC	31,462	18,415	20,936	15,462	5,401	60,213
SPP	4,836	3,986	6,705	3,285	1,030	15,005
TRE	9,275	6,336	10,987	4,244	1,498	23,064
WECC	26,974	9,304	17,831	11,099	2,235	40,468
Total USA	**117,251**	**65,051**	**90,651**	**57,733**	**17,343**	**230,778**

Regions: ASCC = Alaska Systems Coordinating Council; HICC = Hawaiian Islands Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.

Table A9: Criteria pollutant and greenhouse gas emissions by region, 2016

	Output	Criteria and Hazardous Air Pollutants (tons)				Greenhouse Gases (MMT CO2e)		
NERC	**Net Generation (in thousands of MWh)**	**Sulfur Oxides**	**Nitrogen Oxides**	**Particulate Matter**	**Mercury**	**Carbon Dioxide**	**Nitrous Oxides**	**Methane**
ASCC	6,335	260	340	60	0.00	1	0.03	0.02
FRCC	229,408	34,692	44,973	4,332	0.08	112	0.23	0.14
HICC	9,949	773	526	615	0.00	1	0.02	0.01
MRO	222,471	141,011	98,218	6,033	0.56	136	0.59	0.23
NPCC	241,852	6,922	19,289	184	0.01	61	0.07	0.04
RFC	924,072	411,167	319,268	22,277	0.73	501	1.97	0.81
SERC	1,095,473	360,346	309,439	32,063	0.71	565	1.97	1.08
SPP	231,175	130,252	77,784	6,558	0.26	145	0.51	0.15
TRE	384,152	182,850	72,979	5,659	0.49	200	0.63	0.34
WECC	730,646	90,613	180,586	17,552	2.46	282	0.95	0.50
Total	**4,075,533**	**1,358,887**	**1,123,401**	**95,332**	**5.31**	**2,003**	**6.97**	**3.32**

Regions: ASCC = Alaska Systems Coordinating Council; HICC = Hawaiian Islands Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.

Table A10: Criteria pollutant and greenhouse gas emissions rates by region, 2016

	Output	Criteria and Hazardous Air Pollutants (tons/MWh)				Greenhouse Gases (tons CO2e/MWh)		
NERC	Net Generation (in thousands of MWh)	Sulfur Oxides	Nitrogen Oxides	Particulate Matter	Mercury	Carbon Dioxide	Nitrous Oxides	Methane
ASCC	6,335	0.041	0.054	0.009	0	112	5.12	2.76
FRCC	229,408	0.151	0.196	0.019	0	490	1.00	0.61
HICC	9,949	0.078	0.053	0.062	0	68	2.12	1.11
MRO	222,471	0.634	0.441	0.027	0	613	2.67	1.04
NPCC	241,852	0.029	0.080	0.001	0	250	0.30	0.17
RFC	924,072	0.445	0.346	0.024	0	542	2.13	0.88
SERC	1,095,473	0.329	0.282	0.029	0	516	1.79	0.99
SPP	231,175	0.563	0.336	0.028	0	627	2.22	0.67
TRE	384,152	0.476	0.190	0.015	0	520	1.63	0.88
WECC	730,646	0.124	0.247	0.024	0	386	1.30	0.68
Total	**4,075,533**	**0.333**	**0.276**	**0.023**	**0**	**491**	**1.71**	**0.82**

Regions: ASCC = Alaska Systems Coordinating Council; HICC = Hawaiian Islands Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = Southeastern Electric Reliability Council; TRE = Texas Reliability Entity; WECC = Western Electricity Coordinating Council.