

Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors of the U.S. Electric Generating Units in 2010

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September 2013

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ACRONYMS

AMPD	Air Markets Program Data
ASCC	Alaska Systems Coordinating Council
CAP	Criteria air pollutant
CC	Combined cycle
CHP	Combined heat and power
EGU	Electric generating unit
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse gas
GREET TM	The Greenhouse gases, Regulated Emissions, and Energy use in Transportation model
GT	Gas turbine
HICC	Hawaiian Islands Coordinating Council
ICE	Internal combustion engine
IGCC	Integrated Gasification Combined Cycle
LCA	Life-cycle analysis
LHV	Lower-heating value
MRO	Midwest Reliability Organization
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
PDF	Probability distribution function
RFC	Reliability First Corporation
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool, RE
ST	Steam turbine
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

ACKNOWLEDGEMENT

This study was supported by the Bioenergy Technology Office, Vehicle Technology Office, and Fuel Cell Technology Office in the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Argonne, a U.S. Department of Energy Office of Science laboratory, is operated under Contract DE-AC02-06CH11357.

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1 BACKGROUND

Life-cycle analysis (LCA) of the energy use, greenhouse gas (CO₂, CH₄, and N₂O, hereinafter GHG), and criteria air pollutant (CO, NO_x, VOC, PM₁₀, PM_{2.5}, and SO_x, hereinafter CAP) emissions of various vehicle and fuel technologies requires the quantification of energy and emission burdens of electricity generation, because many processes consume electricity. Argonne updated the energy efficiencies and GHG and CAP emission factors of the U.S. electricity generation for various power generation systems with different fuels and technologies.

The total electricity generation in the United States has been increasing almost steadily during the past few decades, but the types of fuels consumed for electricity generation have varied year by year, as shown in Figure 1, with increased shares of natural gas and renewable power generation and a reduction of coal power in the past few years. In addition to the changes in the U.S. electricity generation mixes (EIA, 2013a), generation technology mixes recently have been evolved that have improved energy efficiencies and reduced environmental impacts. For example, more coal-fired power plants are adopting supercritical technology, and the first ultra-supercritical coal-fired power plant recently began operation in the United States (EIA, 2013b). These advances have affected the thermal performance and environmental impacts of the power sector. Moreover, installation and operation of more SO_x, PM, and NO_x emission control devices, as estimated by Equation (1) and shown in Figure 2, have directly and indirectly improved the environmental performance of that sector. To reflect the changes of energy efficiencies and GHG and CAP emission factors in response to the generation mix and technology advances of the U.S. power sector, Argonne National Laboratory (Argonne) analyzed the generation unit-level data on the thermal performance and emissions of non-combined heat and power (CHP) electric generating units (EGUs) in 2010, which were recently published by the U.S. Energy Information Administration (EIA) and the U.S. Environmental Protection Agency (EPA). Based on the updated GHG and CAP emission factors and energy efficiencies of EGUs, new probability distribution functions (PDFs) for power plant efficiencies and emissions were also generated using best-fit statistical curves to characterize the uncertainties associated with lifecycle GHG and CAP emission estimation using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREETTM) model developed at Argonne (Argonne, 2013).

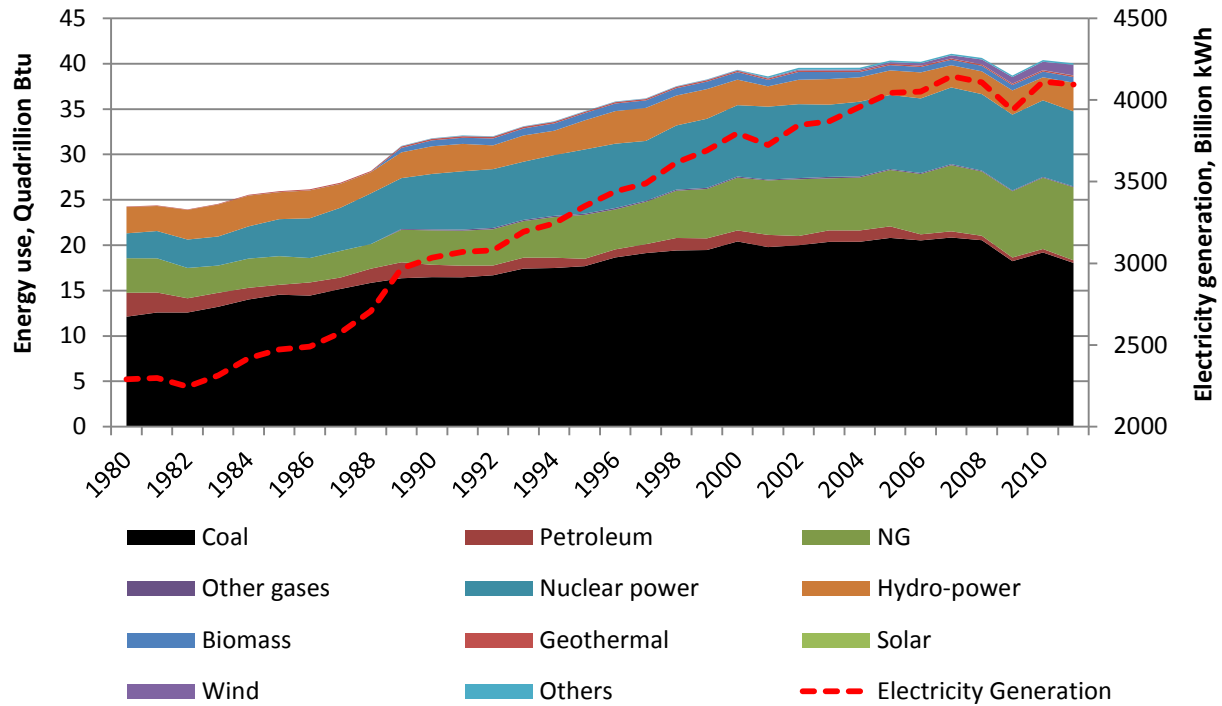


Figure 1. Historical trend of total electricity generation and fuel consumption for electricity generation in the United States, 1980–2011 (EIA, 2013c).

The fugitive PM_{10} and $PM_{2.5}$ emission from coal mining was a major source to the life-cycle PM emissions of coal-fired power plants. We adopted the PM_{10} and $PM_{2.5}$ emission factors that are recently proposed by EPA for coal surface mining (EPA, 2013a). The emission factors are 11.9 g/mmBtu for PM_{10} and 1.49 g/mmBtu for $PM_{2.5}$, respectively. For underground coal mining, the emission factors of 0.299 and 0.019 g/mmBtu for PM_{10} and $PM_{2.5}$ (Xstrata, 2012), respectively, were adopted.

2 METHOD AND DATA

We refined and applied our previously documented methodology (Cai et al., 2012) to characterize the lower-heating value (LHV) based energy efficiencies and the GHG and CAP emission factors of the U.S. power sector in 2010. The refinement of the methodology is three-fold: first, instead of using the CO₂ emissions from the Air Markets Program Data (AMPD) published by the EPA (EPA, 2013b), we estimated the unit-level CO₂ emissions using the carbon balance method based on the quantity and carbon content of the fuel consumed by each EGU, the latter of which was based on the USGS survey data (USGS, 2006) in our previous analysis (Cai et al., 2012). This carbon balance approach has been consistently employed for estimating CO₂ emissions associated with other energy systems in GREET. The SO_x and NO_x emission data in the AMPD database are thoroughly verified according to the procedures outlined in 40 CFR Part 75. Hence, we relied on the AMPD data to estimate SO_x and NO_x emission factors. Second, we determined and applied the unit-level implementation rates of PM control technologies and the corresponding heat input rates to calculate the plant-level PM emission factors. In particular, the desulfurization rates used for PM emission factor calculations were determined based on the heat input of the bituminous-, subbituminous-, and lignite-fired EGUs within each power plant. This led to improved estimation of the PM emissions from various EGUs that employ different emissions control technologies but belong to a single power plant. Third, we discontinued the use of median absolute deviation-based modified Z scores (Iglewicz and Hoaglin, 1993) to detect the potential outliers because the minority outliers detected by this statistical metric are usually the super emitters and could reasonably exist in reality due to the lack of installation and operation of emission control devices and/or due to poor combustion performances from very low energy efficiencies. We used this modified methodology to estimate the emission factors of CO, VOC, PM₁₀, and PM_{2.5} in 2010.

We aggregated different pieces of data from various EIA and EPA datasets that contained 2010 data based on the same plant ID, fuel type, and combustion technology in that year. The aggregated datasets include (1) EIA's Form 923, which included 10,105 unit-level data on net generation, fuel consumption, fuel type, and combustion technology, as well as 6904 unit-level information on the sulfur content, ash content, and heat content of fuels burned (EIA, 2013d); and (2) the unit-level data on SO_x and NO_x emissions as well as the SO_x and PM emission control technologies adopted by EGUs using the EPA's AMPD database (EPA, 2013b). Table 1 shows the shares of SO_x, NO_x and PM emission control technologies adopted by various EGU fuel types and combustion technologies in 2010 as a percentage of the total electricity generated by each fuel type and combustion technology, following Equation (1). We also discontinued the use of the eGRID data (EPA, 2012) because its latest data covered the year 2009 and thus was 1 year older than the 2010 EIA regulatory surveyed data. Furthermore, the EIA data contains up-to-date comprehensive information on the unit-level electricity generation, fuel type, fuel quantity, fuel quality, and combustion technology for a total of 10,035 EGUs in 2010. In our analysis, we excluded the EGUs that did not report to EIA about their operational performance and emission data.

$$EP_{i,j} \% = \frac{Generation_{EC_{i,j}}}{Generation_{Total,j}} \quad (1)$$

where $EP_{i,j} \%$ is the emission control penetration rate of pollutant i of power plants by fuel type j ; $Generation_{EC_{i,j}}$ is the generation of power plants by fuel type j with emission control for pollutant i ; and $Generation_{Total,j}$ is the total generation of power plants by fuel type j .

Table 1 Share of adoption of SO_x, NO_x, and PM emission control technologies by EGU fuel type and combustion technology, a percentage of total electricity generation by each EGU in 2010 (EPA, 2013b)

Fuel Type, Combustion Technology	PM	SO _x	NO _x
Biomass, boiler	100%	15.9%	71.2%
Coal, boiler	99.6%	60.4%	96.0%
NGCC	0.0%	0%	97.6%
NG, GT	0.0%	0%	96.0%
NG, boiler	9.1%	0%	42.5%
Oil, boiler	48.8%	14.0%	66.4%
Oil, GT	0.0%	0%	44.5%

3 RESULTS

3.1 National Average Energy Efficiencies, Combustion Technology Shares, and GHG and CAP Emission Factors by Fuel Type and Generation Technology

The LHV-based energy efficiencies, GHG and CAP emission factors, and generation technology shares averaged at the national level are summarized in Table 2. The generation technology shares are determined by the ratio of the amount of electricity generated by each combustion technology to the total electricity generation.

The efficiency for coal IGCC as shown in Table 2 is about 1.9 percentage points lower than what has been reported before for the same IGCC plant (Ratafia-Brown et al., 2002). We believe the lower efficiency we estimated based on the EIA data in 2010 is reasonable, because this IGCC plant had a normal capacity factor of 0.56, and it is understandable that the efficiency could vary due to changes in coal properties and operational performances.

The NO_x and SO_x emissions factors for oil-fired boilers are higher than coal- and NG-fired boilers, primarily because the NO_x and SO_x emission control deployment rates are much lower for oil-fired boilers than coal- and NG-fired boilers, as shown in Table 1. The reason PM_{10} and $\text{PM}_{2.5}$ emission factors are higher for oil-fired boilers than those for oil-fired internal combustion engines (ICE) is primarily that the majority of the fuel burned by oil-fired boilers is residual oil that has much higher sulfur content than the distillate oil that dominates the fuel that goes into oil-fired ICEs. Higher sulfur content in the oil results in higher PM emissions. The higher CO and VOC emission factors for oil-fired boilers compared to those for oil-fired ICEs and turbines are partly due to the lower combustion temperature as a result of higher NO_x emission control deployment rate, as shown in Table 1, which results in less complete combustion and thus higher CO and VOC emissions for oil-fired boilers.

3.2 Energy Efficiencies, Shares of Fuel Type and Combustion Technology, and GHG and CAP Emission Factors by Fuel Type and Generation Technology by NERC Region

Energy efficiencies, shares of fuel type and combustion technology, and GHG and CAP emission factors in each of the ten North American Electric Reliability Council (NERC) utility regions are summarized in Table 3.

Table 2 National average energy efficiencies, combustion technology shares for each fuel type, and GHG and CAP emission factors (g/kWh) of the U.S. power sector in 2010

Fuel Type, Combustion Technology	Efficiency	Technology Shares	CO₂^a	CO₂^b	CH₄	N₂O	NO_x	SO_x	PM₁₀	PM_{2.5}	CO	VOC
Biomass, ST	21.9%	100.0%			0.4927	0.0657	0.9267	0.6030	2.8140	1.9763	4.7546	0.1349
Coal, IGCC	34.8%	0.1%	980	983	0.0103	0.0155	0.1167 ^c	0.0403 ^c	2.4693	0.7198	0.02191	0.0012
Coal, ST	34.7%	99.9%	997	983	0.0104	0.0156	1.1410	3.1998	0.2836	0.1994	0.1221	0.0147
NG, CC	50.6%	82.1%	441	401	0.0077	0.0008	0.1175	0.0041	0.0009	0.0009	0.0980	0.0018
NG, GT	31.6%	5.5%	652	642	0.0114	0.0011	0.3452	0.0172	0.0386	0.0386	0.4458	0.0114
NG, ICE	32.8%	0.9%	619	618	0.0110	0.0011	3.0829 ^d	0.0061 ^d	0.4718	0.4718	3.8187	1.1102
NG, ST	32.3%	11.5%	638	628	0.0111	0.0011	0.8653	0.1745	0.0426	0.0426	0.4821	0.0320
Oil, GT	29.4%	18.2%	1037	987	0.0351	0.0070	2.9759	0.9438	0.3011	0.0763	0.0181	0.0030
Oil, ICE	36.3%	4.6%	872	800	0.0297	0.0059	4.7442 ^e	0.2274 ^e	0.0138	0.0130	0.0315	0.0119
Oil, ST	33.0%	77.2%	896	880	0.0329	0.0066	4.4825	7.6442	0.1797	0.1395	0.1676	0.0216

^a This is the CO₂ emission factor calculated using the approach in this memo.

^b This is the CO₂ emission factor calculated based on the carbon contents of coal mix, pipeline NG, and residual oil in GREET.

^c Adjusted based on the averaged emission factors for coal IGCC in 2007 (Cai et al., 2012) and the emission reduction rates of NO_x and SO_x for coal-fired power plants from 2007 to 2010, based on the EPA's AMPD data (EPA, 2013b).

^d Adjusted based on the 2007 emission factors for NG ICE (Cai et al., 2012) and the emission reduction rates of NO_x and SO_x for NG-fired power plants from 2007 to 2010, based on the EPA's AMPD data (EPA, 2013b).

^e Adjusted based on the 2007 emission factors for oil ICE (Cai et al., 2012) and the emission reduction rates of NO_x and SO_x for oil-fired power plants from 2007 to 2010, based on the EPA's AMPD data (EPA, 2013b).

Table 3 (Cont.)

Fuel Type, Combustion Technology	Efficiency	Generation Mix and Tech Shares ^a	CO ₂	CH ₄	N ₂ O	NO _x	SO _x	PM ₁₀	PM _{2.5}	CO	VOC
HICC		0.2%	890	0.043	0.008			0.281	0.195	0.267	0.024
NG	43.2%	3.4%	477	0.008	0.001	0.295 ^b	0.013 ^b	0.026	0.026	0.326	0.008
GT	43.2%	100.0%	477	0.008	0.001	0.295 ^b	0.013 ^b	0.026	0.026	0.326	0.008
Oil	34.5%	96.3%	892	0.032	0.006	1.123 ^c	0.554 ^c	0.221	0.151	0.133	0.021
GT	37.1%	3.4%	1042	0.036	0.007	1.586 ^c	0.134 ^c	0.338	0.081	0.018	0.002
ICE	37.3%	6.6%	849	0.029	0.006	4.342 ^c	0.180 ^c	0.010	0.010	0.031	0.012
ST	34.0%	79.9%	874	0.032	0.006	0.779 ^c	0.656 ^c	0.222	0.173	0.158	0.024
Renewable		0.3%									
MRO		5.8%	1122	0.015	0.015	1.342	3.177	0.155	0.122	0.210	0.022
Biomass	20.7%	0.3%		0.522	0.070	3.146	1.723	2.515	1.804	5.022	0.142
ST	20.7%	100.0%		0.522	0.070	3.146	1.723	2.515	1.804	5.022	0.142
Coal	34.4%	65.5%	1149	0.010	0.016	1.385	3.316	0.139	0.110	0.156	0.019
ST	34.4%	100.0%	1149	0.010	0.016	1.385	3.316	0.139	0.110	0.156	0.019
NG	40.3%	3.3%	539	0.009	0.001	0.243	0.045	0.044	0.044	0.460	0.083
CC	48.5%	70.6%	460	0.008	0.001	0.108	0.004	0.001	0.001	0.102	0.002
GT	28.2%	18.2%	729	0.013	0.001	0.685	0.009	0.040	0.040	0.498	0.013
ICE	30.6%	5.9%	663	0.012	0.001	6.232 ^c	0.009 ^c	0.528	0.528	4.275	1.243
ST	28.6%	5.3%	720	0.013	0.001	2.292	4.898	0.041	0.041	0.498	0.033
Nuclear		15.1%									
Oil	30.0%	0.3%	1052	0.036	0.007	3.938	0.458	0.151	0.064	0.143	0.007
GT	19.8%	17.2%	1570	0.054	0.011	3.790	0.440	0.509	0.122	0.027	0.003
ICE	33.1%	7.4%	943	0.033	0.007	6.415 ^c	0.223 ^c	0.011	0.011	0.034	0.013
ST	33.4%	75.4%	944	0.032	0.006	7.959 ^b	7.553 ^b	0.083	0.056	0.179	0.007
Renewable		15.4%									
NPCC		6.4%	621	0.033	0.008	0.394	1.103	0.209	0.150	0.406	0.025
Biomass	23.6%	1.4%		0.457	0.061	0.738	0.234	2.614	1.836	4.395	0.125
ST	23.6%	100.0%		0.457	0.061	0.738	0.234	2.614	1.836	4.395	0.125
Coal	32.8%	10.3%	953	0.011	0.016	1.055	4.320	0.259	0.185	0.112	0.014
ST	32.8%	100.0%	953	0.011	0.016	1.055	4.320	0.259	0.185	0.112	0.014

Table 3 (Cont.)

Fuel Type, Combustion Technology	Efficiency	Generation Mix and Tech Shares ^a	CO ₂	CH ₄	N ₂ O	NO _x	SO _x	PM ₁₀	PM _{2.5}	CO	VOC
NG	46.0%	41.0%	496	0.009	0.001	0.090	0.004	0.015	0.015	0.219	0.021
CC	50.9%	80.3%	460	0.008	0.001	0.067	0.004	0.001	0.001	0.102	0.002
GT	33.2%	4.6%	621	0.011	0.001	0.534	0.014	0.036	0.036	0.424	0.011
ICE	31.4%	1.1%	646	0.011	0.001	1.299 ^c	0.001 ^c	0.524	0.524	4.239	1.232
ST	33.1%	14.0%	623	0.011	0.001	0.225	0.008	0.038	0.038	0.427	0.028
Nuclear		30.5%									
Oil	30.0%	1.1%	989	0.036	0.007	3.811	3.642	0.146	0.084	0.150	0.023
GT	30.6%	19.6%	1084	0.037	0.008	3.166	1.648	0.348	0.083	0.019	0.007
ICE	32.8%	1.1%	962	0.033	0.007	3.448 ^c	0.226 ^c	0.011	0.011	0.035	0.013
ST	30.1%	79.3%	965	0.036	0.007	3.924	3.898	0.099	0.086	0.183	0.027
Renewable		15.7%									
RFC		24.3%	876	0.012	0.014	1.102	3.755	0.363	0.238	0.145	0.016
Biomass	22.1%	0.1%		0.489	0.065	1.095	0.503	2.824	1.904	4.706	0.133
ST	22.1%	100.0%		0.489	0.065	1.095	0.503	2.824	1.904	4.706	0.133
Coal	34.9%	59.6%	920	0.010	0.015	1.213	4.223	0.393	0.257	0.108	0.013
ST	34.9%	100.0%	920	0.010	0.015	1.213	4.223	0.393	0.257	0.108	0.013
NG	45.4%	9.6%	509	0.009	0.001	0.135	0.007	0.022	0.022	0.270	0.039
CC	50.1%	83.5%	473	0.008	0.001	0.101	0.005	0.001	0.001	0.105	0.002
GT	29.9%	8.5%	690	0.012	0.001	0.428	0.013	0.049	0.049	0.471	0.012
ICE	31.6%	2.5%	642	0.011	0.001	2.708 ^c	0.003 ^c	0.510	0.510	4.126	1.200
ST	31.9%	5.5%	647	0.011	0.001	0.504	0.036	0.040	0.040	0.358	0.029
Nuclear		28.0%									
Oil	31.6%	0.3%	989	0.034	0.007	6.097	6.674	0.157	0.080	0.150	0.011
GT	26.1%	18.7%	1147	0.039	0.008	2.017	0.449	0.372	0.089	0.020	0.006
ICE	27.4%	1.1%	1138	0.039	0.008	4.019 ^c	0.370 ^c	0.032	0.028	0.041	0.016
ST	32.5%	80.1%	949	0.033	0.007	7.009	8.861	0.110	0.079	0.180	0.012
Renewable		2.4%									
SERC		27.3%	856	0.011	0.012	0.745	2.207	0.188	0.148	0.149	0.014
Biomass	19.9%	0.2%		0.544	0.073	7.130	0.393	2.819	2.014	5.245	0.149
ST	19.9%	100.0%		0.544	0.073	7.130	0.393	2.819	2.014	5.245	0.149

Table 3 (Cont.)

Fuel Type, Combustion Technology	Efficiency	Generation Mix and Tech Shares^a	CO₂	CH₄	N₂O	NO_x	SO_x	PM₁₀	PM_{2.5}	CO	VOC
Oil	33.7%	0.2%	960	0.032	0.006			0.105	0.058	0.138	0.009
GT	27.6%	12.1%	1191	0.039	0.008	0.831 ^c	0.088 ^c	0.280	0.067	0.021	0.002
ICE	39.0%	15.5%	823	0.028	0.006	3.551 ^c	0.287 ^c	0.010	0.010	0.030	0.011
ST	33.9%	72.4%	951	0.032	0.006	7.841 ^b	7.441 ^b	0.096	0.067	0.181	0.009
Renewable		29.3%									

^a The numbers in bold and italic bold represent the state generation mixes based on EIA's Annual Energy Outlook 2013 and the state generation share of the U.S. total generation, respectively, while others represent the combustion technology shares by fuel type.

^b Adjusted based on the national average emission factors in Table 2 and the combustion efficiencies on the national average in Table 2 and by NERC region.

^c Adjusted based on the emission factors in 2007 (Cai et al., 2012) and the emission reduction rates of NO_x and SO_x of the same fuel type and combustion technology from 2007 to 2010, based on the EPA's AMPD data (EPA, 2013b).

3.3 Probability Distribution Functions of GHG and CAP Emission Factors and Energy Efficiencies by Fuel Type and Combustion Technology of EGUs

Table 4 summaries the PDFs of energy efficiency, GHG and CAP emission factors by fuel type, and combustion technology of non-CHP EGUs for the national average in 2010. The best-fit PDFs are based on the 11 default PDFs in GREET's Add-on Stochastic Tool (Subramanyan and Diwekar, 2005) for stochastic simulations of lifecycle GHG and CAP emissions of various vehicle/fuel systems.

Table 4 Probability distribution functions of energy efficiency, GHG and CAP emission factors by fuel type and combustion technology of EGUs in 2010

Fuel Type	Combustion Technology	Efficiency, GHG, CAP	Best of 11			
			PDF Types	PDF Parameters		
Coal	BLR	Efficiency	Weibull (alpha, beta, gamma)	26.082	0.35405	
		CO ₂	Normal (sigma, mu)	118.0	997.08	
		CH ₄	Weibull	3.665	0.00347	0.00713
		N ₂ O	Weibull	3.6649	0.0052	0.01069
		NO _x	Weibull	2.0053	1.2852	0
		SO ₂	Gamma (alpha, beta, gamma)	1.2684	2.5227	0
		PM ₁₀	Weibull	1.1218	0.28503	0.01458
		PM _{2.5}	Gamma	3.0305	0.06307	0.0083
		VOC	Logistic (sigma, mu)	0.00153	0.01469	
		CO	Logistic	0.01255	0.12207	
Natural gas	BLR	Efficiency	Weibull	19.186	0.33285	0
		CO ₂	Gamma	66.901	9.5186	0
		CH ₄	Gamma	8.0828	2.5603E-4	0.00908
		N ₂ O	Gamma	8.0828	2.5603E-5	9.0755E-4
		NO _x	Weibull	1.7204	0.94335	0
		SO ₂	Weibull	0.52076	0.09678	1.0112E-4
		PM ₁₀	Weibull	3.7423	0.04285	0
		PM _{2.5}	Weibull	3.7423	0.04285	0
		VOC	Weibull	3.788	0.02875	0.00334
		CO	Weibull	3.9626	0.48177	0.00417
	CT	Efficiency	Weibull	11.001	0.33243	0
		CO ₂	Weibull	4.6486	688.26	0
		CH ₄	Weibull	4.6486	0.01203	0
		N ₂ O	Weibull	4.6486	0.0012	0
		NO _x	Gamma	2.4422	0.14275	-0.004
		SO ₂	Weibull	0.87497	0.01541	0
		PM ₁₀	Gamma	5.1213	0.00754	0

Table 4. (Cont.)

Fuel Type	Combustion Technology	Efficiency, GHG, CAP	Best of 11			
			PDF Types	PDF Parameters		
Oil	CC	PM _{2.5}	Gamma	5.1213	0.00754	0
		VOC	Weibull	4.6485	0.01205	0
		CO	Weibull	4.6486	0.47034	0
		Efficiency	Weibull	10.789	0.49596	
		CO ₂	Lognormal	0.12506	6.0798	
		CH ₄	Gamma	23.546	3.2691E-4	0
		N ₂ O	Gamma	46.376	1.4572E-5	9.3569E-5
		NO _x	Gamma	0.60871	0.19296	0
		SO ₂	Gamma	9.0203	3.9314E-4	5.2007E-4
		PM ₁₀	Gamma	23.546	3.7735E-5	0
		PM _{2.5}	Gamma	23.546	3.7735E-5	0
		VOC	Gamma	23.546	7.7543E-5	0
		CO	Gamma	23.546	0.00416	0
	ICE	Efficiency	Weibull	4.8579	0.35752	
		CO ₂	Logistic	48.435	618.66	
		CH ₄	Logistic	8.6235E-4	0.01096	
		N ₂ O	Logistic	8.6235E-5	0.0011	
		PM ₁₀	Logistic	0.05871	0.47184	
		PM _{2.5}	Logistic	0.05871	0.47184	
		VOC	Logistic	0.13815	1.1102	
		CO	Logistic	0.47519	3.8187	
	BLR	Efficiency	Weibull	18.83	0.33896	0
		CO ₂	Gamma	6.5491	24.718	734.51
		CH ₄	Gamma	12.302	6.3328E-4	0.0251
		N ₂ O	Gamma	12.302	1.2666E-4	0.00502
		NO _x	Weibull	1.1438	4.7566	0
		SO ₂	Gamma	3.6389	2.1675	0
		PM ₁₀	Logistic	0.04483	0.17971	
		PM _{2.5}	Normal	0.06014	0.13952	
		VOC	Normal	0.00559	0.02162	
		CO	Gamma	2.5432	0.05795	-1.4002E-4
	CT	Efficiency	Weibull	4.7642	0.33963	0
		CO ₂	Logistic	175.42	1006.5	
		CH ₄	Gamma	38.994	0.00113	-0.00884
		N ₂ O	Gamma	38.994	2.2670E-4	-0.00177
		NO _x	Weibull	1.2522	3.7895	0
		SO ₂	Weibull	1.071	0.9712	0

Table 4. (Cont.)

Fuel Type	Combustion Technology	Efficiency, GHG, CAP	Best of 11		
			PDF Types	PDF Parameters	
Biomass	ICE	PM ₁₀	Logistic	0.06094	0.30122
		PM _{2.5}	Weibull	1.776	0.09508 0
		VOC	Gamma	2.4682	0.00122 3.2686E-5
		CO	Gamma	42.562	5.3952E-4 -0.00477
		Efficiency	Gamma	79.028	0.00466 -4.6389E-4
		CO ₂	Weibull	7.0769	906.81 0
		CH ₄	Gamma	106.26	3.2290E-4 -0.0046
		N ₂ O	Weibull	6.2643	0.00598 2.0959E-4
		PM ₁₀	Weibull	1.3362	0.01532 0
		PM _{2.5}	Weibull	1.4475	0.01456 0
		VOC	Weibull	7.0783	0.0124 0
		CO	Weibull	7.0783	0.03273 0
	BLR	Efficiency	Lognormal	0.15385	-1.5034
		CH ₄	Weibull	5.2917	0.52382 0
		N ₂ O	Weibull	5.2917	0.06984 0
		NO _x	Gamma	0.61517	1.2142 0.18634
		SO ₂	Weibull	0.87056	0.56781 0
		PM ₁₀	Logistic	0.64717	2.814
		PM _{2.5}	Logistic	0.4613	1.9763
		VOC	Weibull	5.3198	0.14308 0
		CO	Weibull	5.3141	5.0469 0

3.4 Projection of CAP Emission Factors from 2010 to 2020

CAP emission factors of the power sector are affected by various factors, primarily the fuel quality, emission control technology, and energy efficiency performance. These factors vary among plants and from year to year, and therefore may result in significant variation in CAP emission factors among different power plants, as illustrated in the Interactive Motion Charts created by the EPA (EPA, 2013c). This creates difficulty in capturing the fundamental drivers behind the variation among individual power plants. Our attempts to correlate the CAP emission factors to these various factors proved that statistically significant correlations were not possible when the dataset of individual power plants was employed. In order to project the CAP emission factors, we investigated the historical trend of the emission rates expressed in g/mmBtu of fuel consumption for the national average of coal-, NG-, oil-fired power plants, and emission factors expressed in g/kWh for biomass-fired power plants, and developed correlations between the emission rates and potential predictors such as the year and emission control penetration rates. For this purpose, we calculated the CAP emission rates/emission factors on the national average in 2002, 2005, 2008, and 2011, based on the CAP emissions from electricity generation by fuel

type in those years as reported in the EPA’s National Emission Inventory (NEI) and on the annual fuel consumption by electricity generation by fuel type as reported by the EIA (EIA, 2013e). The emission rates/emission factors in the period 2002–2011 that had no NEI emission data are linearly interpolated between 2002–2005, 2005–2008, and 2008–2011 to provide enough data points for a regression analysis to investigate the potential historical trend. Using the historical CAP emission rates on the national average from 2002 to 2011, statistically significant regression formulas with high prediction power (as indicated by a high Pearson correlation coefficient or the R^2) were developed for most of the CAP emission factors. These regression formulas are summarized in the Appendix. The “year” as a statistically significant predictor in these regression formulas with high R^2 values indicates that there are certain types of temporal variations in the CAP emission factors, and most of the variation in the CAP emission factors can be captured by this factor.

Using the developed regression formulas, the emission rates in 2015 and 2020 were calculated with the following assumptions: (1) The CAP emission rates will not increase from 2010 to 2020. This means that if the regression formulas predict higher emission rates during 2010 to 2020 than previous years, the emission rates from 2010 to 2020 will remain the same as those in 2010. (2) There will be no negative emission rates. This means that if the regression formulas predict negative emission rates in 2020, the emission rate reduction ratio between 2015 and 2010 will be applied to the period between 2015 and 2020. We calculated the changes in emission rates in 2015 and 2020, respectively, relative to those in 2010, as shown in Table 5. These relative changes were further compared to the emission standards of power plants in the United States (FR, 2012), and necessary adjustments were made by assuming that there will be no emission rates reduction from 2010 to 2020 if the emission rates in 2010 already met the emission standards for newly built power plants. Finally, we applied the relative changes in CAP emission rates in Table 5, with an efficiency gain adjustment that quantifies the effects of improvement in energy efficiencies on emission rates, to project the CAP emission factors in 2015 and 2020, as shown in Table 7. The energy efficiency gains in 2015 and 2020 for various types of power plants are shown in Table 6.

**Table 5 Relative changes in CAP emission rates
(g/mmBtu) in 2015 and 2020 relative to those in 2010**

Fuel Type	Pollutants	Ratio of 2015 to 2010	Ratio of 2020 to 2015
Coal	CO	0.476	0.476
	NO _x	0.375	0.375
	PM ₁₀	0.225	0.225
	PM _{2.5}	0.225 ^a	0.225 ^a
	SO _x	0.766	0.695
	VOC	0.610	0.031
NG	CO	1.000	1.000
	NO _x	1.000	1.000
	PM ₁₀	1.000	1.000
	PM _{2.5}	1.000	1.000
	SO _x	1.000	1.000
	VOC	1.000	1.000
Oil	CO	1.000	1.000
	NO _x	1.000	1.000
	PM ₁₀	1.000	1.000
	PM _{2.5}	1.000	1.000
	SO _x	0.500 ^b	0.200 ^c
	VOC	1.000	1.000
Biomass ^d	CO	1.000	1.000
	NO _x	1.000	1.000
	PM ₁₀	0.747	0.747
	PM _{2.5}	0.747 ^a	0.747 ^a
	SO _x	1.000	1.000
	VOC	1.000	1.000

^a Assumed the same as that for PM₁₀.

^b 50% sulfur emission control technology deployment in 2015 is assumed, compared to nearly zero in 2010.

^c 90% sulfur emission control technology deployment in 2020 is assumed, compared to nearly zero in 2010.

^d The regression formulas for biomass-fired plants predict the results in g/kWh.

Table 6 Projected energy efficiencies in 2015 and 2020 in comparison to those in 2010 by fuel and combustion technology

Fuel Type, Combustion Technology	Energy Efficiency		
	2010	2015	2020
Biomass, ST	22.0%	22.0%	25.0%
Coal, IGCC	35.0%	40.0%	45.0%
Coal, ST	35.0%	36.0%	38.0%
NG, CC	51.0%	55.0%	60.0%
NG, GT	32.0%	34.0%	36.0%
NG, ICE	33.0%	34.0%	36.0%
NG, ST	32.0%	34.0%	36.0%
Oil, GT	29.0%	32.0%	34.0%
Oil, ICE	36.0%	38.0%	40.0%
Oil, ST	33.0%	35.0%	37.0%

Table 7 Projected national average energy efficiencies, and GHG and CAP emission factors (g/kWh) by fuel type and combustion technology of the U.S. power sector in 2015 and 2020

Year	Fuel Type, Combustion Technology	Efficiency	CO ₂	CH ₄	N ₂ O	NO _x	SO _x	PM ₁₀	PM _{2.5}	CO	VOC
2015	Biomass, ST	22.0%		0.4905	0.0654	0.9225	0.6003	2.0938	0.6103	4.7330	0.1343
	Coal, IGCC	40.0%	853	0.0090	0.0135	0.1015	0.0351	1.6965	0.4945	0.0151	0.0009
	Coal, ST	36.0%	961	0.0100	0.0150	0.3619	2.3641	0.0614	0.0432	0.0560	0.0086
	NG, CC	55.0%	406	0.0071	0.0007	0.1081	0.0038	0.0008	0.0008	0.0902	0.0017
	NG, GT	34.0%	606	0.0106	0.0010	0.3208	0.0160	0.0359	0.0359	0.4143	0.0106
	NG, ICE	34.0%	597	0.0106	0.0011	2.9741	0.0059	0.4551	0.4551	3.6839	1.0710
	NG, ST	34.0%	606	0.0105	0.0010	0.8220	0.1658	0.0405	0.0405	0.4580	0.0304
	Oil, GT	32.0%	953	0.0322	0.0064	2.7341	0.4336	0.2766	0.0701	0.0166	0.0028
	Oil, ICE	38.0%	833	0.0284	0.0056	4.5320	0.1086	0.0132	0.0124	0.0301	0.0114
	Oil, ST	35.0%	845	0.0310	0.0062	4.2264	3.6037	0.1694	0.1315	0.1580	0.0204
2020	Biomass, ST	25.0%		0.0090	0.0136	0.8118	0.5282	1.3772	0.4014	4.1650	0.1182
	Coal, IGCC	45.0%	758	0.0080	0.0120	0.0902	0.0312	1.5080	0.4396	0.0134	0.0008
	Coal, ST	38.0%	910	0.0095	0.0142	0.1284	1.5573	0.0131	0.0092	0.0253	0.0003
	NG, CC	60.0%	372	0.0065	0.0007	0.0991	0.0035	0.0008	0.0008	0.0826	0.0015
	NG, GT	36.0%	572	0.0100	0.0010	0.3030	0.0151	0.0339	0.0339	0.3913	0.0100
	NG, ICE	36.0%	564	0.0100	0.0010	2.8089	0.0056	0.4299	0.4299	3.4793	1.0115
	NG, ST	36.0%	572	0.0100	0.0010	0.7764	0.1566	0.0382	0.0382	0.4326	0.0287
	Oil, GT	34.0%	897	0.0304	0.0061	2.5733	0.0816	0.2604	0.0660	0.0157	0.0026
	Oil, ICE	40.0%	791	0.0270	0.0054	4.3054	0.0206	0.0125	0.0118	0.0286	0.0108
	Oil, ST	37.0%	799	0.0293	0.0059	3.9979	0.6818	0.1603	0.1244	0.1495	0.0193

3.5 Electricity generation mixes by NERC region from 1990 to 2020

We evaluated the generation mixes by NERC region from 1990 to 2020 on the basis of various sources of EIA data, primarily the Annual Energy Outlook (EIA, 2013a), the State electricity profiles (EIA, 2013f), and the Form 923 data (EIA, 2013d), as shown in Table 8.

Table 8 Generation mixes by NERC region from 1990 to 2020

ASCC							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
1990	7.50%	63.87%	6.94%	0.00%	0.00%	21.69%	100.00%	0.00%	0.00%	0.00%	0.00%
1995	10.04%	55.27%	6.38%	0.00%	0.00%	28.31%	100.00%	0.00%	0.00%	0.00%	0.00%
2000	11.28%	64.69%	3.74%	0.00%	0.00%	20.29%	100.00%	0.00%	0.00%	0.00%	0.00%
2005	11.53%	60.15%	3.69%	0.00%	0.00%	24.63%	99.96%	0.00%	0.00%	0.00%	0.04%
2010	14.26%	59.38%	3.05%	0.00%	0.87%	22.43%	99.10%	0.00%	0.90%	0.00%	0.00%
2015	14.26%	59.38%	3.05%	0.00%	0.87%	22.43%	99.10%	0.00%	0.90%	0.00%	0.00%
2020	14.26%	59.38%	3.05%	0.00%	0.87%	22.43%	99.10%	0.00%	0.90%	0.00%	0.00%
FRCC							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
1990	20.30%	14.16%	47.78%	17.62%	0.00%	0.14%	42.94%	0.00%	0.00%	0.00%	57.06%
1995	14.67%	23.61%	42.04%	19.53%	0.00%	0.16%	43.09%	0.00%	0.00%	0.00%	56.91%
2000	20.21%	21.19%	39.52%	19.01%	0.00%	0.07%	43.09%	0.00%	0.00%	0.38%	56.53%
2005	18.42%	37.37%	29.35%	14.67%	0.00%	0.19%	42.67%	0.00%	0.00%	1.71%	55.62%
2010	4.24%	58.11%	24.73%	11.20%	0.18%	1.53%	41.41%	0.00%	0.00%	2.47%	56.11%
2015	0.14%	60.93%	19.72%	17.34%	0.28%	1.59%	43.51%	0.00%	0.00%	5.52%	50.98%
2020	0.14%	57.61%	22.35%	17.24%	1.05%	1.61%	40.58%	0.00%	0.00%	5.14%	54.29%
HICC							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
1990	99.64%	0.00%	0.00%	0.00%	0.00%	0.36%	79.13%	0.00%	0.00%	0.00%	20.87%
1995	99.74%	0.00%	0.00%	0.00%	0.00%	0.26%	100.00%	0.00%	0.00%	0.00%	0.00%
2000	99.73%	0.00%	0.00%	0.00%	0.00%	0.27%	85.09%	0.00%	0.00%	0.00%	14.91%
2005	99.84%	0.00%	0.00%	0.00%	0.00%	0.16%	84.38%	0.00%	0.00%	0.00%	15.62%
2010	96.30%	3.41%	0.00%	0.00%	0.00%	0.29%	91.19%	0.00%	0.00%	0.00%	8.81%
2015	96.30%	3.41%	0.00%	0.00%	0.00%	0.29%	91.19%	0.00%	0.00%	0.00%	8.81%
2020	96.30%	3.41%	0.00%	0.00%	0.00%	0.29%	91.19%	0.00%	0.00%	0.00%	8.81%
MRO							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
1990	0.34%	0.61%	72.99%	19.81%	0.00%	6.24%	76.86%	0.00%	17.43%	0.00%	5.70%
1995	0.41%	1.02%	72.25%	18.65%	0.00%	7.66%	70.61%	0.00%	23.64%	0.00%	5.75%

Table 8 (Cont.)

MRO (Cont.)							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
2000	0.42%	1.11%	74.46%	17.73%	0.00%	6.29%	64.36%	0.00%	29.84%	0.00%	5.80%
2005	0.68%	3.62%	74.12%	16.96%	0.00%	4.62%	58.10%	0.00%	36.05%	0.00%	5.85%
2010	0.33%	3.30%	65.52%	15.14%	0.31%	15.41%	54.06%	0.00%	40.07%	0.00%	5.87%
2015	0.25%	1.68%	63.05%	14.72%	0.29%	20.00%	41.18%	0.00%	52.82%	0.00%	6.01%
2020	0.20%	5.20%	59.17%	15.40%	0.48%	19.54%	41.56%	0.00%	52.48%	0.00%	5.97%
NPCC							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
1990	33.60%	17.87%	14.18%	25.48%	0.00%	8.87%	88.24%	0.00%	0.38%	0.00%	11.38%
1995	15.62%	28.62%	11.15%	36.68%	0.00%	7.95%	86.95%	0.00%	2.39%	0.00%	10.65%
2000	14.38%	11.51%	13.22%	58.09%	0.00%	2.80%	85.66%	0.00%	4.41%	0.00%	9.92%
2005	16.40%	10.99%	20.19%	36.49%	0.25%	15.69%	84.37%	0.00%	6.44%	0.00%	9.19%
2010	1.10%	40.95%	10.34%	30.47%	1.41%	15.73%	83.57%	0.00%	7.75%	0.00%	8.67%
2015	0.60%	41.90%	4.76%	32.24%	1.59%	18.91%	80.65%	0.00%	11.91%	0.17%	7.26%
2020	0.12%	42.26%	5.21%	32.04%	1.86%	18.51%	80.85%	0.00%	11.79%	0.17%	7.19%
RFC							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
1990	1.83%	1.09%	77.26%	18.32%	0.00%	1.50%	49.50%	0.00%	6.84%	0.00%	43.66%
1995	1.06%	1.60%	75.28%	20.89%	0.00%	1.18%	49.14%	0.00%	10.63%	0.00%	40.23%
2000	1.00%	1.22%	76.94%	19.55%	0.00%	1.30%	48.76%	0.00%	14.51%	0.00%	36.73%
2005	0.42%	0.95%	88.89%	8.40%	0.00%	1.34%	48.38%	0.00%	18.46%	0.00%	33.15%
2010	0.34%	9.59%	59.61%	27.95%	0.13%	2.38%	33.58%	0.00%	47.08%	0.24%	19.09%
2015	0.23%	13.90%	53.63%	28.20%	0.23%	3.81%	33.04%	0.00%	54.20%	0.95%	11.81%
2020	0.22%	13.82%	52.70%	27.93%	1.47%	3.87%	34.98%	0.00%	52.60%	0.92%	11.50%
SERC							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
1990	0.44%	4.83%	55.63%	32.97%	0.00%	6.14%	100.00%	0.00%	0.00%	0.00%	0.00%
1995	0.44%	5.76%	55.43%	33.64%	0.00%	4.73%	99.78%	0.00%	0.00%	0.00%	0.22%
2000	0.94%	5.09%	55.25%	35.81%	0.00%	2.92%	99.37%	0.00%	0.00%	0.00%	0.63%
2005	1.20%	5.57%	58.27%	30.02%	0.00%	4.94%	97.63%	0.00%	0.00%	0.00%	2.37%

Table 8 (Cont.)

SERC (Cont.)							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
2010	0.53%	17.06%	52.94%	26.04%	0.15%	3.27%	93.68%	0.00%	2.65%	0.03%	3.65%
2015	0.37%	27.27%	41.35%	26.53%	0.42%	4.05%	85.67%	0.00%	9.67%	1.10%	3.56%
2020	0.19%	24.69%	41.48%	28.30%	1.52%	3.82%	84.71%	0.00%	9.58%	2.22%	3.49%
SPP							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
1990	0.13%	24.57%	60.56%	11.10%	0.00%	3.64%	6.72%	0.00%	87.74%	0.00%	5.53%
1995	0.10%	24.28%	60.65%	12.01%	0.00%	2.96%	5.66%	0.00%	89.65%	0.00%	4.69%
2000	0.37%	24.04%	61.93%	11.99%	0.00%	1.67%	4.60%	0.00%	91.55%	0.00%	3.86%
2005	0.75%	29.92%	61.82%	4.50%	0.00%	3.01%	3.53%	0.00%	93.45%	0.00%	3.02%
2010	0.90%	26.86%	59.77%	4.48%	0.00%	7.98%	2.83%	0.00%	94.71%	0.00%	2.46%
2015	0.23%	26.05%	55.63%	4.35%	0.01%	13.73%	0.69%	0.00%	98.53%	0.00%	0.78%
2020	0.17%	31.32%	50.87%	4.21%	0.09%	13.34%	0.70%	0.00%	98.52%	0.00%	0.78%
TRE							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
1990	0.21%	41.56%	50.57%	6.78%	0.00%	0.89%	2.18%	0.00%	97.09%	0.00%	0.73%
1995	0.08%	38.78%	46.67%	13.81%	0.00%	0.65%	2.34%	0.00%	96.71%	0.00%	0.95%
2000	0.40%	40.31%	46.38%	12.63%	0.00%	0.28%	2.51%	0.00%	96.32%	0.00%	1.17%
2005	0.07%	33.96%	51.37%	13.00%	0.00%	1.60%	2.68%	0.00%	95.93%	0.00%	1.39%
2010	0.18%	40.76%	37.68%	13.31%	0.00%	8.07%	2.81%	0.00%	95.52%	0.03%	1.64%
2015	0.14%	43.83%	33.41%	12.79%	0.34%	9.49%	3.08%	0.00%	94.44%	0.71%	1.78%
2020	0.13%	44.43%	33.85%	12.44%	0.32%	8.83%	3.13%	0.00%	94.08%	0.71%	2.08%
WECC							Of the Others:				
	Residual Oil	Natural Gas	Coal	Nuclear	Biomass	Others	Hydroelectric	Geothermal	Wind	Solar PV	Others
1990	0.98%	10.45%	38.29%	12.73%	0.00%	37.56%	66.86%	27.57%	5.57%	0.00%	0.00%
1995	0.14%	9.93%	37.16%	12.34%	0.00%	40.42%	67.05%	26.93%	6.02%	0.00%	0.00%
2000	0.17%	8.71%	40.44%	14.38%	0.00%	36.30%	67.28%	26.19%	6.53%	0.00%	0.00%
2005	0.08%	10.22%	42.32%	13.57%	0.12%	33.69%	67.54%	25.32%	7.14%	0.00%	0.00%
2010	0.25%	28.46%	31.17%	10.33%	0.54%	29.27%	66.65%	24.18%	7.42%	1.43%	0.33%
2015	0.18%	25.11%	30.31%	9.18%	0.28%	34.93%	57.38%	18.65%	7.98%	14.76%	1.24%
2020	0.17%	24.50%	28.22%	10.02%	1.71%	35.38%	54.83%	17.52%	7.50%	13.86%	6.29%

3.6 Urban shares of CAP emissions from power plants

We evaluated the urban shares of CAP emissions from various types of power plants by state based on the location and net electricity generation of power plants (EPA, 2012), as shown in Table 9.

Table 9 Urban shares of CAP emissions from power plants by state in 2010

State	Power plants				
	Coal-fired	NG-fired	Oil-fired	Biomass-fired	Nuclear
CT	100%	100%	100%	100%	100%
DE	32.12%	100.00%	100.00%	0.00%	0.00%
FL	57.93%	67.67%	98.48%	66.80%	58.63%
GA	42.04%	49.85%	98.04%	37.53%	0.00%
MA	34.77%	46.36%	94.77%	52.27%	0.00%
MD	83.43%	31.90%	0.00%	47.08%	100.00%
ME	69.23%	65.12%	71.00%	31.05%	33.42%
NC	62.32%	33.43%	59.99%	4.40%	100.00%
NH	75.01%	0.00%	0.00%	12.90%	0.00%
NJ	73.79%	99.38%	100.00%	100.00%	100.00%
NY	67.98%	39.66%	35.46%	71.06%	61.96%
PA	39.29%	92.75%	99.88%	80.38%	100.00%
RI	0.00%	79.71%	100.00%	0.00%	0.00%
SC	71.48%	56.78%	12.92%	76.13%	33.74%
VA	50.93%	76.62%	36.39%	47.26%	0.00%
VT	0.00%	0.00%	18.06%	55.98%	0.00%
WV	37.45%	100.00%	0.00%	0.00%	0.00%
IL	46.65%	89.24%	98.53%	0.00%	70.99%
IN	29.99%	97.42%	100.11%	100.00%	0.00%
IA	61.19%	38.25%	0.00%	0.00%	100.00%
KS	21.98%	36.19%	0.00%	0.00%	0.00%
KY	26.37%	44.98%	100.00%	0.00%	0.00%
MI	94.12%	83.25%	0.00%	22.69%	100.00%
MN	71.88%	65.13%	73.87%	33.22%	33.42%
MO	71.96%	70.82%	0.00%	0.00%	0.00%
NE	19.66%	39.55%	14.30%	0.00%	39.22%
ND	1.88%	0.00%	98.24%	0.00%	0.00%
OH	54.33%	98.96%	99.60%	16.42%	49.96%
OK	26.23%	61.74%	0.00%	0.00%	0.00%
SD	4.90%	37.23%	0.00%	0.00%	0.00%
TN	46.64%	33.79%	0.00%	30.89%	65.85%
WI	66.49%	69.84%	0.20%	22.81%	0.00%
AL	74.51%	86.06%	100.00%	49.30%	100.00%

Table 9 (Cont.)

State	Power plants				
	Coal-fired	NG-fired	Oil-fired	Biomass-fired	Nuclear
AR	54.48%	12.62%	0.00%	18.98%	0.00%
LA	34.77%	59.34%	100.00%	18.88%	53.32%
MS	58.15%	56.21%	99.90%	0.00%	0.00%
NM	0.00%	15.18%	0.00%	0.00%	0.00%
TX	27.00%	75.93%	92.42%	40.00%	0.00%
CO	50.78%	94.74%	0.00%	0.00%	0.00%
ID	50.13%	0.00%	0.00%	0.00%	0.00%
MT	6.88%	7.10%	100.00%	100.00%	0.00%
UT	2.86%	60.96%	0.00%	100.00%	0.00%
WY	0.00%	0.00%	0.00%	0.00%	0.00%
AK	0.00%	30.72%	0.00%	0.00%	0.00%
AZ	40.58%	99.94%	5.56%	0.00%	100.00%
CA	100.00%	98.30%	87.96%	74.03%	48.79%
HI	87.32%	74.61%	0.00%	94.82%	0.00%
NV	39.88%	84.11%	58.42%	0.00%	0.00%
OR	0.00%	19.13%	0.00%	58.94%	0.00%
WA	0.00%	37.98%	99.52%	31.98%	100.00%
USA	38.00%	31.29%	0.97%	1.26%	22.87%

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5 APPENDIX

Table A1 summarizes the regression formulas to predict CAP emission rates from 2010 to 2020.

Table A1 Regression formulas to predict CAP emission rates (g/mmBtu) for the period 2010 to 2020

Fuel Type	Pollutant	Constant	Year2 ^a	Year	coal_pm_control ^b	oil_pm_control ^c	oil_so2_control ^d
Coal	CO	-668967	-0.16622	666.5088	854.8768		
	NO _x	23749.79		-11.769			
	PM ₁₀	4041.723		-2.00438			
	PM _{2.5}	3666.483		-1.81945			
	SO _x	22317.14		-10.8275	-534.213		
	VOC	-21163.4	-0.00528	21.13464			
NG	CO	1261060	0.312852	-1256.22			
	NO _x	2299595	0.569582	-2288.93			
	PM ₁₀	145125.4	0.036039	-144.64			
	PM _{2.5}	135088.6	0.033548	-134.639			
	SO _x	2246.096		-1.11699			
	VOC	100053.8	0.024807	-99.6396			
Oil	CO	4721162	1.170758	-4702.04			
	NO _x	35500000	8.826457	-35399.2			
	PM ₁₀	69.89013				-97.1508	
	PM _{2.5}	44.6068				-53.5675	
	SO _x	415.071					-3630.27
	VOC	700384	0.174024	-698.235			
Biomass ^e	CO	117824.7	0.029098	-117.106			
	NO _x	186366	0.046159	-185.498			
	PM ₁₀	7132.896	0.00176	-7.08628			
	PM _{2.5}	27.37819		-0.0136			
	SO _x	59774.89	0.014808	-59.5033			
	VOC	5115.411	0.001263	-5.08413			

^a Refers to the product of “year” multiplying “year.”

^b Refers to the PM emission control penetration rate of coal-fired power plants.

^c Refers to the PM emission control penetration rate of oil-fired power plants.

^d Refers to the SO_x emission control penetration rate of oil-fired power plants.

^e The regression formulas for biomass-fired plants predict the results in g/kWh.