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Update of Emission Factors of Greenhouse Gases and Criteria Air Pollutants, and Generation Efficiencies of the U.S. Electricity Generation Sector

Energy Systems Division

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ACRONYMS AND ABBREVIATIONS

AB	agricultural byproduct
ASCC	Alaska Systems Coordinating Council
AP-42	Compilation of Air Emissions Factors
BIT	bituminous coal
CAMD	EPA's Clean Air Markets Division
CAP	criteria air pollutant
CC	combined cycle
CH_4	methane
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
DFO	distillate fuel oil
ECHO	Enforcement and Compliance History Online
EF	emission factor
eGRID	Emissions & Generation Resource Integrated Database
EGU	Electric Generating Utility
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FC	fuel cell
FRCC	Florida Reliability Coordinating Council
FRS	Facility Registry Service
GHG	greenhouse gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model
GT	combustion gas turbine
HHV	higher heating value
HICC	Hawaiian Islands Coordinating Council
IC	internal combustion engine
IGCC	integrated gasification combined cycle
JF	jet fuel
KER	kerosene
LHV	lower heating value

LIG	lignite coal
MATS	Mercury and Air Toxics Standards
MRO	Midwest Reliability Organization
MSW	municipal solid waste
N_2O	nitrous oxide
NEI	National Emission Inventory
NEG	net electricity generated
NERC	North American Electric Reliability Council
NG	natural gas
NGCC	natural gas combined cycle
NO_x	nitrogen oxides
NPCC	Northeast Power Coordinating Council
OBL	other biomass liquids
OBS	other biomass solids
ORISPL	Office of the Regulatory Information System PLant
PC	petroleum coke
PDF	probability density function
$PM_{2.5}$	particulate matter up to 2.5 micrometers in size
PM_{10}	particulate matter up to 10 micrometers in size
RC	refined coal
RFC	Reliability First Corporation
RFO	residual fuel oil
SERC	SERC Reliability Corporation
SO_x	sulfur oxides
SPP	Southwest Power Pool
ST	steam turbine
SUB	subbituminous coal
T&D	transmission and distribution
TRE	Texas Regional Entity
VOC	volatile organic compounds
WC	waste/other coal
WECC	Western Electricity Coordinating Council
WDS	wood/wood waste solids
WO	waste/other oil

1 BACKGROUND

The last decade has seen a steady evolution of the electricity generation sector. Fuels used for electricity generation have shifted from coal to cleaner energy sources such as natural gas and renewables including solar, wind, and other renewable sources.[1] The share of U.S. electricity generated from coal decreased from 45% in 2010 to 24% in 2019, and is expected to decrease further to 13% by 2050.[1] The conversion efficiency of electricity generation has also increased gradually for fuels such as natural gas due as less-efficient old generators are retired and more-efficient generators replace them.[2] These changes in the electricity generation industry are likely to cause changes in the emissions from power generation units.

Emission factors of greenhouse gases (GHG) including CO_2, CH_4, and N_2O, and criteria air pollutants (CAPs) including CO, NO_x, PM_{10}, $PM_{2.5}$, and SO_x, from power plants are important parameters for estimating life-cycle emissions associated with vehicle electrification, energy systems, and the production of materials and chemicals. The electricity generation technologies and associated emission factors in the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET)[3] model need to be updated to reflect recent developments in the electricity generation sector.

The most recent update of the electricity generation emission factors in GREET adopted a mixed method.[4] The emission factors of CH_4, N_2O, NO_x, and SO_x were estimated using a "top-down" approach by dividing the total emissions by the total net electricity generation, because emission data of these pollutants are readily available in the Emissions & Generation Resource Integrated Database (eGRID). For other CAPs such as CO, VOC, PM_{10}, and $PM_{2.5}$, emission data were not reported in eGRID. A "bottom-up" method was used to estimate the emission factors for these pollutants by considering generic uncontrolled emission factors and the pollutant removal efficiencies of emission control technologies adopted in the electricity generation sector. However, the uncontrolled emission factors and the emission removal efficiencies of various emission control technologies considered in the 2012 study[4] came from the legacy AP-42 emission factors,[5] and may not reflect the actual emission performances of the electricity generation sector of today.

To leverage new data that recently became available, especially emission data measured from continuous emission monitoring systems (CEMS), we developed a new "top-down" approach to estimate efficiencies and GHG and CAP emission factors for electricity generation from combustion of individual fuel types by individual combustion technologies on the basis of power-generation data from U.S. Energy Information Administration's (EIA's) form EIA-923,[6] and plant emission data from Environmental Protection Agency's (EPA's) Clean Air Markets Division (CAMD) dataset and National Emissions Inventory (NEI) dataset.[7-8] Detailed discussion of the method and data used in this study can be found in Section 2.1. With this top-down approach, we aim to improve the estimates of energy efficiencies and emission factors for power plants using a more consistent methodology, and to update the emission factors, generation efficiencies, and generation technologies mixes in GREET to reflect recent technology advancements in the electricity generation sector.

2 METHOD AND DATA

2.1 DATA

Heat input, net electricity generation, and emission data are needed to calculate the energy efficiencies and emission factors for power generated by combusting a particular fuel using a specific combustion technology. The main data sources used in this study are listed below:

1. EIA-923 dataset.[6] Fuel type, combustion technology, heat input, and net power generation for each power plant in the year 2017 are obtained from EIA-923.

2. CAMD dataset downloaded as part of the Air Emissions Data Set from the EPA Enforcement and Compliance History Online (ECHO) website.[9] It includes annual facility-level CO_2, NO_x, and SO_x emission data for the power plants reporting to CAMD programs. The majority of reported emissions in this dataset are from CEMS and are generally considered the highest quality air emissions data.[10] This study used the 2017 CAMD dataset.

3. NEI dataset.[7] This dataset contains information on stationary and mobile sources that emit criteria air pollutants and hazardous air pollutants. The current study used process-level emission data for point emission sources in 2017 NEI data, which is the latest data when this study was performed.

EIA-923 is an important data source for eGRID. It reported detailed heat input and net generation at the plant level from fuel and combustion technology. It would therefore allow users to identify the plants that primarily burned a single (or dominant) fuel using primarily a single (or dominant) combustion technology. Efficiencies and emission factors of those plants better represent the characteristics of the combination of the corresponding fuel and combustion technology, as compared to those that do not differentiate plant emissions and electricity generation that may come from combustion of multiple fuels with multiple combustion technologies.

CAMD's Power Sector Emission Data is also an important data source for eGRID. It includes data reported to the U.S. Environmental Protection Agency (EPA) by electric generating units (EGU) to meet regulatory requirements. eGRID used monitored data from CAMD's Power Sector Emission Data to estimate CO_2, NO_x, and SO_x emissions where available. For those units that do not report to the EPA, eGRID calculated the emission factors based on EIA-923 reported emission rates where available and a fuel- and combustion technology-specific emission factor for the units whose emission rates are not reported in EIA-923. In this study, we used the CAMD emission data wherever available, and NEI emission data when the pollutants and power plants were not included in the CAMD emission data.

The emission data for EGU in the NEI dataset are from data reported by state, local, and tribal agencies wherever available. In the absence of reported data, the emission data are from three sources: annual sums of SO_x and NO_x emissions reported to the CAMD database, the 2010 Mercury and Air Toxics Standards (MATS) rule development testing program emission factors, and heat-input-based emission factors built from Compilation of Air Pollutant Emissions Factors (AP-42). The NEI dataset includes a larger number of power plant and pollutants than the CAMD dataset.

2.2 EFFICIENCY

Because the heat input of each power plant in EIA-923 is calculated based on the higher heating value (HHV) of the burning fuel, but GREET uses the lower heating value (LHV) of fuels to calculate electricity generation efficiencies, we used the ratio between the LHV and the HHV of a fuel in GREET to estimate LHV-based efficiencies. The efficiency of power plants depends on the fuel and combustion technology used. The efficiency can be estimated using Equation (1):[4]

$$\eta_{LHV,r,f,ct} = \frac{\sum_i NEG_{r,f,ct,i} \times kWh2mmBtu}{\sum_i H_{r,f,ct,i} \times k_f} \times 100\% \quad (1)$$

where

$\eta_{LHV,r,f,ct}$ (expressed in %) is the LHV-based energy efficiency by fuel type *f* and combustion technology *ct* in region *r*;

$kWh2mmBTU$ is the unit converter of per-kWh electricity to mmBtu, which is 0.003412 mmBtu per kWh;

$NEG_{r,f,ct,i}$ (expressed in kWh) is the annual net electricity generation from power plant *i* burning fuel *f* using combustion technology *ct* in region *r*;

$H_{f,ct,i}$ (expressed in mmBtu) is the annual heat input of from power plant *i* burning fuel *f* using combustion technology *ct*; and

k_f (unitless) is the ratio between the lower heating value and higher heating value of fuel type *f*. k_f is obtained from an earlier GREET update in 2012.[4]

2.3 EMISSION FACTORS

In this work, we used a top-down approach to estimate GHG and CAP emission factors for power plants. The emission factor of a particular pollutant from a power plant burning a specific fuel and employing a specific combustion technology is estimated using Equation (2):

$$EF_{r,p,f,ct} = \frac{\sum_i Emission_{r,p,f,ct,i}}{\sum_i NEG_{r,f,ct,i}} \quad (2)$$

where

$EF_{r,p,f,ct}$ (expressed in g/kWh) is the averaged emission factor of a GHG species or pollutant p emitted by all power plants burning fuel f using combustion technology ct in region r;

$Emission_{r,p,f,ct,i}$ (expressed in grams) is the annual emissions of a GHG species or pollutant p from power plant i burning fuel f using combustion technology ct in region r; and

$NEG_{r,f,ct,i}$ (expressed in kWh) is the annual net electricity generated by power plant i burning fuel f using combustion technology ct in region r.

The net electricity generation $NEG_{f,ct,i}$ was obtained from plant-level EIA-923 data.[6] The emission data $Emission_{p,f,ct,i}$ come from two sources. Annual emissions of CO_2, NO_x, and SO_x were from EPA's CAMD data whenever available.[8] For the power plants that do not report to CAMD, NO_x and SO_x emissions were collected from NEI.[7] Because the latest NEI data were released in 2017, the 2017 EIA-923 and CAMD data were also used to estimate net power generation and emissions, respectively, of CO_2, NO_x, and SO_x. Details are discussed below.

2.3.1 Power Plants with a Dominating Fuel and Combustion Technology

For each power plant, EIA-923 reported heat input and net power generation from burning a specific fuel and combustion technology in the reporting year. It is important to differentiate power generation from different fuels and combustion technologies that present different emission characteristics.

We first screened and removed the combinations of fuel and combustion technology that have negative electricity generation (possibly because of their operations in spinning reserve mode) for each power plant. Those combined heat and power (CHP) facilities, which accounted for 9% of total net electricity in 2017, are also excluded from calculation of efficiencies and emission factors because there is a lack of consensus on how to allocate emissions between the electricity and heat coproducts.[4]

Many power plants adopted more than one fuel and/or combustion technology in 2017. The emissions from these plants are the result of burning more than one fuel with multiple combustion technologies. In order to calculate the emission factor for a specific fuel and combustion technology, we selected power plants that have a dominant fuel and combustion technology. We define a power plant to have a dominant fuel and combustion technology if more than 98% of its net power generation came from burning a specific fuel using a specific combustion technology. The 98% threshold is high enough to obtain a reasonably good estimate of the emission factors for a specific fuel and combustion technology, while not being too restrictive, so that we still have a reasonably good number of power plants to represent the given fuel type and the engaged combustion technology.

2.3.2 Linking Power Generation Data with Emission Data

After down-selecting the power plants with a dominant fuel and combustion technology, emissions from these power plants were obtained. As stated above, the emission data of these power plants came from two data sources: CAMD and NEI datasets. For the power plants that report to CAMD, facility-level CO_2, NO_x, and SO_x emissions were obtained from the CAMD dataset. Emissions of other pollutants from these power plants were derived from the NEI dataset. For the power plants that do not report to CAMD, their emission data were also taken from the NEI dataset.

Because EIA-923 and the CAMD dataset both use the same Office of the Regulatory Information System PLant (ORISPL) code as the Energy Information Administration (EIA) to identify power plants, it is straightforward to link the power generation data in EIA-923 to the emission data from CAMD for the power plants that are present in both datasets.

It is not as convenient to link the power plants between EIA-923 and the NEI datasets, because NEI used a different identifier from EIA-923 for the facilities. EPA uses the Facility Registry Service (FRS)[11] to link air emission sources across various datasets such as EIA-923 and NEI. Each facility will be assigned to an FRS registry identifier (ID) through which it is possible to link facilities across multiple datasets such as CAMD and NEI. However, a few issues make it more complicated to link different datasets for some facilities. The following are some issues with FRS:

1) Some facilities were assigned multiple FRS IDs due to slight differences in the plant name, address, etc., in different datasets such as EIA-923 and NEI.

2) On certain occasions, more than one power plant in EIA-923 was assigned the same FRS ID because they share the same parent company. Consequently, they will be linked to the same facility in NEI.

3) Some power plants in EIA-923 can match with more than one NEI facility using FRS. This is usually because FRS included outdated NEI facility IDs that were no longer in use for these power plants.

For these reasons, only around half of the down-selected power plants in EIA-923 can be linked with an NEI facility based on FRS ID. The rest of the power plants need to be manually linked between EIA-923 and NEI. In order to improve the accuracy of the estimated emission factors, we manually linked 41 power plants in EIA-923 with NEI facilities based on their company name, latitude, longitude, address, zip code, parent company, and other identifying information; therefore, the linked power plants cover at least 80% of net power generation from burning a specific fuel using a particular combustion technology in the United States.

Another issue with the data sources is that NEI reported comprehensive process-based emissions for each source while CAMD only reports emissions directly from power generation (e.g., turbines and boilers). In other words, NEI included emissions from processes that do not directly stem from power generation, such as feedstock handling and drying, gas compression, and fugitive emissions. In addition, for a small number of power plants, emission data of some of its EGUs are included in the NEI datasets but not in the CAMD datasets. Such differences can lead to significant discrepancies between the CAMD and NEI datasets for some power plants.

For instance, the total NO_x emissions from the NGCC power plant of ORISPL code 117 reported by NEI is 4 times higher than the NO_x emissions reported by NEI for the same power plant. This is because the CAMD emission data covered only three out of the nine electricity generated-related processes included in NEI. The emission reported by CAMD is more in line with the emission data of other NGCC power plants of similar size. This discrepancy between the two datasets indicate that we need to filter the processes in NEI data to include only the processes that are included in the CAMD dataset.

The differences in the processes covered by the CAMD and NEI datasets require that the process-level emission data in NEI be down-selected before the calculation of GHG and CAP emission factors. Because we used net power generation and NO_x and SO_x emissions from CAMD whenever available, we only considered emissions from the processes included in CAMD when collecting the facility-level emissions of other pollutants (CH_4, N_2O, CO, $PM_{2.5}$, and PM_{10}) from the NEI dataset. For the plants for which it is not straightforward to determine which processes were included in CAMD data and those that did not report to CAMD, we manually selected processes that were directly related to electricity generation (for instance, emissions from combustion of fuels), while the other processes such as feedstock handling and drying, gas compression, and fugitive emissions were excluded from our calculation of facility-level emissions.

Once facility-level emissions were compiled for the plants with a dominant burning fuel type and combustion technology, we plugged their emissions and net power generation into Equation (2) to calculate the fuel- and combustion technology-specific emission factors for each power plant.

2.4 PROBABILITY DENSITY FUNCTIONS OF EFFICIENCIES AND EMISSION FACTORS

To address the variation and uncertainty associated with the estimations of energy efficiencies and emission factors, we developed the probability density functions (PDFs) of the emission factors and plant efficiencies by fuel type and combustion technology based on the performance of individual plants. A toolbox called EasyFit Professional developed by Mathwaves was used to develop a number of PDFs for each of the emission factors and plant efficiency based on multiple commonly used statistical goodness-of-fit criteria (e.g., Kolmogorov Smirnov[12] and Anderson Darling[13]). We used the calculated fuel/combustion technology-specific emission factors of individual plants as sample data values and used the corresponding net electricity generation of each plant as the probability density value. The best-fit PDF based on the goodness-of-fit criteria was selected from a gallery of built-in PDFs in EasyFit and in GREET.

2.5 ELECTRICITY TRANSMISSION AND DISTRIBUTION LOSS FACTORS

National- and state-level electricity T&D loss factors were calculated using the latest data from EIA's State Electricity Profiles,[14] which reported electricity losses, total disposition, interstate exports, and direct use data in each state and in the nation in 2018. National- and state-level electricity T&D loss factors were calculated by dividing the remainder of disposable electricity minus net interstate exports and direct plant use by the estimated losses in each state, as follows:[15]

$$T\&D\ Loss = \frac{Estimated\ Losses}{Total\ Disposition - Net\ Interstate\ Exports - Direct\ Use} \tag{3}$$

where

Estimated Losses	(expressed in MWh) is the electricity that is lost in transmission and distribution;
Total Disposition	(expressed in MWh) is the total amount of electricity that is sold for resale, consumed by respondent without charge, and lost. It is equal to the total amount of electricity generated;
Net Interstate Exports	(expressed in MWh) is the total amount of electricity exported to other states. The total net interstate exports for the United States is zero;
Direct Use	(expressed in MWh) is the total amount of electricity used by plants and/or utilities that is not sold or sale. Direct use electricity is not transmitted through the grid and thus does not have the potential to be lost.

3 RESULTS

3.1 COVERAGE OF PLANTS LINKED BETWEEN POWER GENERATION AND EMISSIONS DATA

Table 1 shows the coverage for each fuel and combustion technology of the power plants whose power generation data (from EIA-923) and emission data (from CAMD and/or NEI) are linked. Nuclear power generation and renewable electricity (hydropower, wind, and geothermal electricity), which accounted for 39% of the total electricity generation, do not undergo this linking process. For the other fuel types including coal and natural gas, which altogether accounted for 60% of total U.S. electricity generation in 2017, the coverage of the power plants for each major combustion technology is more than 80%. Coverage of biomass-fired power plants is also high, even though it only accounts for a small portion of power generation. Note that power generation derived from municipal solid waste (MSW) accounts for around 51% of power generation from biomass combustion, but none of the power plants used MSW as their dominant fuel. Therefore, no MSW-fired power plants met the requirement that 98% of the electricity be produced using a dominant fuel and combustion technology, and none were included in Table 1. The share of dominant combustion technology in Table 1 is calculated by total net electricity generation from power plants from the plants with dominant fuel subtype and combustion technology divided by the total net electricity generation from the fuel subtype and combustion technology. For instance, a coverage of 80% indicates that electricity generation from power plants with a dominant fuel subtype and combustion technology accounts for 80% of the total electricity from the corresponding fuel with the corresponding combustion technology. The coverage in Table 1 is calculated by Equation (4). A coverage of 100% indicates that all the power plants with the corresponding dominant fuel and combustion technology are linked between the power generation and emission data:

$$Coverage_{f,ct} = \frac{\sum_{i \in P} NEG_{f,ct,i}}{\sum_{i \in A} NEG_{f,ct,i}} \tag{4}$$

where

$NEG_{f,ct,i}$ (expressed in kWh) is the net electricity generation from power plant *i* burning fuel *f* as the dominant fuel using a dominant combustion technology *ct*;

A is the set of all the power plants burning fuel *f* as the dominant fuel using a dominant combustion technology *ct*; and

P is the set of the power plants burning fuel *f* as the dominant fuel using a dominant combustion technology *ct* whose emission data (CAMD and NEI) and power generation data (EIA-923) have been linked.

Coverage is low for power plants fired by certain types of oil (e.g., KER), but they accounted for a minimal fraction (<0.05%) of total electricity generation. The process of linking the electricity generation data and the emission data for the power plants is challenging as EPA's FRS only works for about half the plants; the rest must be linked manually based on information such as plant coordinates, zip code, and address. This makes it difficult to automate the linking process. As a result, the linking process consumes a great deal of time and effort in this update. If consistent plant identifiers were to be used for the EIA-923 and NEI datasets in the future, the linking process could be skipped in future updates for the power plants whose power generation data and emission data have already been linked in the current study. Instead, efforts could be devoted to linking the plants that have not been linked between the EIA-923 and NEI datasets to further increase the data coverage and representation.

TABLE 1 Share of net power generation for fuel and combustion technology, and their coverage.[a]

Fuel type (share)[b]	Fuel subtype (share)[c]	Combustion technology (share)[d]	Share of dominant combustion technology	Coverage
NG (32.8%)	NG (100.0%)	CC (87.5%)	85.9%	80.4%
		ST (6.7%)	47.5%	83.8%
		GT (5.4%)	65.1%	80.3%
		IC (0.3%)	89.9%	80.7%
Coal (30.0%)	SUB (38.8%)	ST (100.0%)	79.8%	81.5%
	BIT (35.9%)	ST (99.8%)	76.9%	84.5%
	RC (19.6%)	ST (100.0%)	70.1%	86.4%
	LIG (4.7%)	ST (100.0%)	78.6%	100.0%
	WC (0.5%)	ST (100.0%)	86.7%	100.0%
	PC (0.5%)	ST (100.0%)	16.8%	100.0%
Biomass (1.4%)	MSW (50.9%)	ST (100.0%)	91.3%	83.0%
	WDS (45.2%)	ST (99.5%)	77.7%	85.7%
	OBS (1.9%)	ST (100.0%)	80.0%	100.0%
	AB (1.8%)	ST (100.0%)	73.2%	100.0%
Oil (0.3%)	DFO (48.2%)	GT (18.1%)	25.9%	81.1%
		IC (16.6%)	44.3%	69.4%
	RFO (45.9%)	ST (100.0%)	62.9%	93.9%
	WO (4.6%)	CC (95.8%)	31.5%	100.0%
	KER (1.0%)	GT (80.6%)	77.5%	12.4%
	JF (0.1%)	GT (59.6%)	85.3%	100.0%

[a] NG: natural gas. SUB: subbituminous coal. BIT: bituminous coal. RC: refined coal. LIG: lignite coal. WC: waste/other coal. PC: petroleum coke. MSW: municipal solid waste. WDS: wood/wood waste solids. OBS: other biomass solids. AB: agricultural byproduct. DFO: distillate fuel oil. RFO: residual fuel oil. WO: waste/other oil. KER: kerosene. JF: jet fuel. CC: combined cycle. ST: steam turbine. GT: gas turbine. IC: internal combustion engine.
[b] The percentages indicate the shares of fuel in the total electricity generation in the United States.
[c] The percentages indicate the share of the fuel subtype in the total electricity generated from the corresponding fuel type.
[d] The percentages indicate the share of the combustion technology in the total electricity generated from the fuel subtype.

3.2 ELECTRICITY GENERATION EFFICIENCIES

Tables 2 and 3 show the national and regional electricity generation efficiencies. The electricity generation efficiencies in Table 3 will be used to update the efficiencies in GREET 2019, which were estimated by projections of the historical trend.[16]

When comparing the efficiencies obtained in this study to historical efficiencies, slight gains in electricity generation efficiencies have been seen in natural-gas-fired power plants. The national average efficiency of natural-gas combined-cycle (NGCC) power plants increased from 50.6%[16] in 2010 to 51.6% in 2017. Power plants burning natural gas with internal combustion engines achieved a high efficiency gain from 32.8% from 2010 to 41.0% in 2017. The estimated efficiency (41.0%) is well within reported range (28–46%) of energy efficiencies of burning natural gas using internal combustion engines.[17] The increase in energy efficiency is partly attributable to the advancements in engine technology.[18] Another reason for the increased energy efficiency of the natural gas internal combustion engines is a trend of installing large engines, which operate more efficiently than small engines,[17, 19] throughout the United States since 2010.[18]

3.3 EMISSION FACTORS

Tables 4 and 5 show the generation-weighted national and regional average emission factors by fuel and combustion technology, respectively.

TABLE 2 National and regional energy conversion efficiencies by fuel subtype and combustion technology.[a]

Fuel type (share)[b]	Fuel subtype (share)[c]	Combustion technology (share)[d]	National	ASCC	FRCC	HICC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC
NG (32.8%)	NG (100.0%)	CC (87.5%)	51.6%	44.6%	52.4%	NA	51.9%	50.9%	52.1%	52.1%	50.8%	51.2%	50.4%
		ST (6.7%)	33.8%	NA	41.2%	NA	28.9%	33.5%	33.3%	33.4%	31.8%	32.2%	31.1%
		GT (5.4%)	32.9%	25.6%	34.5%	NA	31.0%	32.6%	32.7%	33.1%	30.6%	28.6%	34.3%
		IC (0.3%)	41.0%	43.3%	19.1%	NA	42.2%	37.6%	40.2%	33.5%	40.0%	39.9%	41.3%
Coal (30.0%)	SUB (38.8%)	ST (100.0%)	34.7%	NA[e]	NA	NA	35.1%	28.9%	34.1%	35.0%	34.9%	34.4%	34.5%
	BIT (35.9%)	ST (99.8%)	34.8%	NA	34.1%	NA	16.5%	32.0%	34.8%	35.2%	34.0%	NA	34.2%
	RC (19.6%)	ST (100.0%)	34.2%	NA	NA	NA	33.3%	NA	34.6%	34.1%	26.5%	35.6%	32.9%
	LIG (4.7%)	ST (100.0%)	34.0%	25.2%	NA	NA	32.5%	NA	NA	30.7%	34.4%	34.5%	NA
	WC (0.5%)	ST (100.0%)	30.1%	24.1%	NA	NA	NA	NA	30.5%	NA	NA	NA	28.4%
	PC (0.5%)	ST (100.0%)	34.6%	NA	34.9%	NA	NA	NA	35.7%	32.8%	34.4%	24.6%	NA
Biomass (1.4%)	MSW (50.9%)	ST (100.0%)	19.6%	NA	18.7%	20.3%	18.3%	20.5%	19.7%	17.0%	NA	NA	20.0%
	WDS (45.2%)	ST (99.5%)	24.6%	NA	20.5%	NA	22.4%	25.6%	26.8%	25.7%	NA	26.0%	22.8%
	OBS (1.9%)	ST (100.0%)	17.4%	NA	16.2%	NA	30.4%	24.5%	NA	23.8%	NA	NA	NA
	AB (1.8%)	ST (100.0%)	26.8%	NA	NA	23.1%	26.3%	NA	NA	24.7%	NA	NA	29.6%
Oil (0.3%)	DFO (48.2%)	GT (18.1%)	26.8%	28.2%	31.6%	21.1%	20.5%	20.6%	27.3%	28.0%	19.2%	25.4%	20.4%
		IC (16.6%)	34.9%	37.2%	24.8%	36.7%	31.4%	28.9%	18.9%	25.6%	30.5%	31.3%	34.7%
	RFO (45.9%)	ST (100.0%)	32.5%	NA	30.1%	33.1%	NA	30.5%	29.9%	29.7%	NA	NA	NA
	KER (1.0%)	GT (80.6%)	29.0%	NA	NA	NA	30.2%	28.8%	32.3%	NA	NA	NA	NA
	JF (0.1%)	GT (59.6%)	24.7%	NA	NA	NA	NA	22.9%	19.3%	NA	28.7%	NA	25.0%

[a] Plant efficiencies higher than 1 (likely due to a mistake in data) are removed before calculation. ASCC: Alaska Systems Coordinating Council. FRCC: Florida Reliability Coordinating Council. HICC: Hawaiian Islands Coordinating Council. MRO: Midwest Reliability Organization. NPCC: Northeast Power Coordinating Council. RFC: Reliability First Corporation. SERC: SERC Reliability Corporation. SPP: Southwest Power Pool. TRE: Texas Regional Entity. WECC: Western Electricity Coordinating Council. NG: natural gas. SUB: subbituminous coal. BIT: bituminous coal. RC: refined coal. LIG: lignite coal. WC: waste/other coal. PC: petroleum coke. MSW: municipal solid waste. WDS: wood/wood waste solids. OBS: other biomass solids. AB: agricultural byproduct. DFO: distillate fuel oil. RFO: residual fuel oil. KER: kerosene. JF: jet fuel. CC: combined cycle. ST: steam turbine. GT: gas turbine. IC: internal combustion engine.

[b] The percentages indicate the shares of fuel in the total electricity generation in the United States.

[c] The percentages indicate the share of the fuel subtype in the total electricity generated from the corresponding fuel type.

[d] The percentages indicate the share of the combustion technology in the total electricity generated from the fuel subtype.

[e] NA: not available.

TABLE 3 National and regional energy conversion efficiencies by fuel type and combustion technology, in comparison to previous projection of national average values.[a]

Fuel type (share)[b]	Combustion technology (share)[c]	Calculation method	National	ASCC	FRCC	HICC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC
NG (32.8%)	CC (83.1%)	This study	51.6%	44.6%	52.4%	NA[d]	51.9%	50.9%	52.1%	52.1%	50.8%	51.2%	50.4%
		GREET 2019	55.0%	38.3%	50.9%	55.0%	48.5%	50.9%	50.1%	50.9%	49.5%	50.3%	51.1%
	GT (8.8%)	This study	32.9%	25.6%	34.5%	NA	31.0%	32.6%	32.7%	33.1%	30.6%	28.6%	34.3%
		GREET 2019	34.0%	29.9%	31.8%	43.2%	28.2%	33.2%	29.9%	32.2%	31.1%	29.1%	32.8%
	ST (7.1%)	This study	33.8%	NA	41.2%	NA	28.9%	33.5%	33.3%	33.4%	31.8%	32.2%	31.1%
		GREET 2019	34.0%	34.0%	33.0%	34.0%	28.6%	33.1%	31.9%	31.9%	32.5%	31.9%	32.0%
	IC (1.0%)	This study	41.0%	43.3%	19.1%	NA	42.2%	37.6%	40.2%	33.5%	40.0%	39.9%	41.3%
		GREET 2019	34.0%	34.0%	33.9%	34.0%	30.6%	31.4%	31.6%	33.1%	35.5%	35.4%	34.4%
Coal (30.0%)	ST (100.0%)[e]	This study	34.5%	24.7%	34.1%	NA	34.2%	31.7%	34.6%	34.8%	34.8%	34.5%	34.3%
		GREET 2019	36.0%	26.0%	34.8%	22.5%	34.4%	32.8%	34.9%	34.9%	34.3%	34.7%	34.7%
Biomass (1.4%)	ST (100.0%)	This study	21.7%	NA	18.7%	20.6%	20.6%	22.4%	21.5%	24.4%	NA	26.0%	22.7%
		GREET 2019	22.0%	39.9%	18.5%	22.9%	20.7%	23.6%	22.1%	19.9%	38.7%	22.0%	22.6%
Oil (0.3%)	ST (76.6%)	This study	32.6%	23.7%	31.0%	33.1%	31.2%	30.2%	32.9%	32.7%	33.7%	32.8%	34.0%
		GREET 2019	35.0%	35.0%	33.2%	34.0%	33.4%	30.1%	32.5%	33.3%	34.0%	32.4%	33.9%
	GT (13.5%)	This study	26.9%	28.2%	31.6%	21.1%	20.5%	24.9%	27.2%	28.0%	20.1%	25.4%	21.4%
		GREET 2019	32.0%	39.7%	28.2%	37.1%	19.8%	30.6%	26.1%	27.5%	54.9%	29.5%	27.6%
	IC (9.9%)	This study	34.9%	37.2%	24.8%	36.7%	31.4%	28.9%	18.9%	25.6%	30.5%	31.3%	34.7%
		GREET 2019	38.0%	36.5%	32.9%	37.3%	33.1%	32.8%	27.4%	35.0%	29.9%	23.9%	39.0%

[a] Plant efficiencies higher than 1 (likely due to mistake in data) are removed before calculation. ASCC: Alaska Systems Coordinating Council. FRCC: Florida Reliability Coordinating Council. HICC: Hawaiian Islands Coordinating Council. MRO: Midwest Reliability Organization. NPCC: Northeast Power Coordinating Council. RFC: Reliability First Corporation. SERC: SERC Reliability Corporation. SPP: Southwest Power Pool. TRE: Texas Regional Entity. WECC: Western Electricity Coordinating Council. NG: natural gas. CC: combined cycle. GT: gas turbine. ST: steam turbine. IC: internal combustion engine.

[b] The percentages indicate the shares of fuel in the total electricity generation in the United States.

[c] The percentages indicate the share of the combustion technology in the total electricity generated from the fuel type. The shares are normalized values after excluding minor technologies such as fuel cells for NG, IGCC for coal, and combined cycles for oil.

[d] NA: not available

[e] There is one coal-fired IGCC EGU (ORISID 7242), but it only generated 0.07% of total coal-based electricity generated in 2018.

TABLE 4 National generation-weighted average emission factors in g/kWh by fuel subtype and combustion technology.[a]

Fuel type (share)[b]	Fuel subtype (share)[c]	Combustion technology (share)[d]	NO_x	SO_x	$PM_{2.5}$	PM_{10}	VOC	CO	CH_4	N_2O
NG (32.8%)	NG (100.0%)	CC (87.5%)	0.050	0.007	0.017	0.017	0.004	0.034	0.009	0.001
		ST (6.7%)	0.654	0.010	0.035	0.036	0.025	0.339	NA[e]	NA
		GT (5.4%)	0.264	0.005	0.041	0.041	0.017	0.151	0.030	0.008
		IC (0.3%)	0.167	0.011	0.054	0.054	0.093	0.183	0.008	0.002
Coal (30.0%)	SUB (38.8%)	ST (100.0%)	0.731	1.124	0.043	0.061	0.015	0.381	NA	NA
	BIT (35.9%)	ST (99.8%)	0.728	0.644	0.068	0.082	0.010	0.166	0.158	0.023
	RC (19.6%)	ST (100.0%)	0.654	0.866	0.065	0.084	0.016	0.225	NA	NA
	LIG (4.7%)	ST (100.0%)	0.622	1.736	0.092	0.115	0.009	0.925	NA	NA
	WC (0.5%)	ST (100.0%)	0.787	2.527	0.044	0.049	0.007	0.336	NA	NA
	PC (0.5%)	ST (100.0%)	0.439	2.019	0.165	0.224	0.001	0.053	NA	NA
Biomass (1.4%)	MSW (50.9%)	ST (100.0%)	1.266	0.108	0.033	0.033	0.011	0.154	NA	NA
	WDS (45.2%)	ST (99.5%)	0.640	0.041	0.065	0.069	0.033	1.164	0.113	0.060
	OBS (1.9%)	ST (100.0%)	1.013	0.011	0.135	0.145	0.003	1.919	NA	NA
	AB (1.8%)	ST (100.0%)	1.303	0.271	0.096	0.100	0.029	0.864	NA	NA
Oil (0.3%)	DFO (48.2%)	GT (18.1%)	3.359	0.905	0.082	0.110	0.010	0.228	0.048	0.010
		IC (16.6%)	13.614	0.483	0.832	0.814	0.689	2.114	0.070	0.069
	RFO (45.9%)	ST (100.0%)	2.251	2.737	0.131	0.161	0.011	0.082	NA	NA
	KER (1.0%)	GT (80.6%)	18.755	2.826	2.076	2.218	1.199	18.411	NA	NA
	JF (0.1%)	GT (59.6%)	3.994	0.958	0.549	0.553	0.062	0.285	0.051	0.010

[a] NG: natural gas. SUB: subbituminous coal. BIT: bituminous coal. RC: refined coal. LIG: lignite coal. WC: waste/other coal. PC: petroleum coke. MSW: municipal solid waste. WDS: wood/wood waste solids. OBS: other biomass solids. AB: agricultural byproduct. DFO: distillate fuel oil. RFO: residual fuel oil. KER: kerosene. JF: jet fuel. ST: steam turbine. CC: combined cycle. GT: gas turbine. IC: internal combustion engine.
[b] The percentages indicate the shares of fuel in the total electricity generation in the United States.
[c] The percentages indicate the share of the fuel subtype in the total electricity generated from the corresponding fuel type.
[d] The percentages indicate the share of the combustion technology in the total electricity generated from the fuel subtype.
[e] NA: not available.

TABLE 5 NERC regional generation-weighted average emission factors in g/kWh by fuel subtype and combustion technology.[a]

NERC region	Fuel type (share)[b]	Fuel subtype (share)[c]	Combustion technology (share)[d]	NO_x	SO_x	$PM_{2.5}$	PM_{10}	VOC	CO	CH_4	N_2O
ASCC	NG (50.4%)	NG (100.0%)	CC (66.7%)	0.533	0.005	0.004	0.023	0.010	0.123	NA[e]	NA
			IC (23.8%)	0.050	0.015	0.017	0.017	0.041	0.026	NA	NA
			GT (9.4%)	1.488	0.017	0.054	0.058	0.413	0.648	NA	NA
	Oil (13.6%)	DFO (60.0%)	IC (69.8%)	13.498	0.326	0.603	0.544	0.587	1.760	0.000	NA
			GT (26.6%)	9.525	3.903	0.134	0.134	0.006	0.048	NA	NA
FRCC	NG (68.6%)	NG (100.0%)	CC (86.9%)	0.048	0.002	0.022	0.022	0.002	0.050	NA	NA
			ST (7.7%)	0.550	0.003	0.036	0.036	0.026	0.019	NA	NA
			GT (5.4%)	0.213	0.003	0.032	0.032	0.009	0.077	NA	NA
	Coal (15.1%)	BIT (97.2%)	ST (99.5%)	0.440	1.022	0.109	0.133	0.005	0.308	NA	NA
	Biomass (2.4%)	MSW (74.1%)	ST (100.0%)	1.427	0.101	0.046	0.036	0.013	0.121	NA	NA
		WDS (16.4%)	ST (100.0%)	0.753	0.066	0.071	0.071	0.020	0.595	NA	NA
		OBS (9.5%)	ST (100.0%)	1.013	0.011	0.135	0.145	0.003	1.919	NA	NA
HICC	Oil (67.7%)	RFO (72.9%)	ST (100.0%)	2.251	2.737	0.131	0.161	0.011	0.082	NA	NA
		DFO (24.3%)	IC (28.0%)	7.930	0.001	0.208	0.214	0.109	0.141	NA	NA
	Biomass (4.8%)	MSW (78.1%)	ST (100.0%)	1.048	0.003	0.011	0.014	0.002	0.074	NA	NA
		AB (10.3%)	ST (100.0%)	1.770	0.298	0.013	0.013	0.162	0.561	NA	NA

TABLE 5 (Cont.)

NERC region	Fuel type (share)[b]	Fuel subtype (share)[c]	Combustion technology (share)[d]	NO_x	SO_x	$PM_{2.5}$	PM_{10}	VOC	CO	CH_4	N_2O
MRO	Coal (51.0%)	SUB (55.0%)	ST (100.0%)	0.641	1.378	0.038	0.046	0.017	0.418	NA	NA
		RC (31.6%)	ST (100.0%)	1.110	0.426	0.105	0.128	0.021	0.228	NA	NA
		LIG (13.4%)	ST (100.0%)	1.074	2.695	0.128	0.152	0.018	0.282	NA	NA
	NG (7.6%)	NG (100.0%)	CC (77.8%)	0.047	0.002	0.006	0.007	0.001	0.118	0.010	0.001
			GT (17.2%)	0.422	0.005	0.026	0.028	0.009	0.195	0.011	0.001
			ST (4.0%)	1.290	0.007	0.055	0.055	0.048	0.392	NA	NA
			IC (1.1%)	0.361	0.003	0.097	0.098	0.140	0.706	0.009	0.001
	Biomass (0.7%)	MSW (45.9%)	ST (100.0%)	1.410	0.070	0.019	0.020	0.003	0.197	NA	NA
	Oil (0.1%)	DFO (95.8%)	GT (33.6%)	6.320	0.020	0.107	0.107	0.000	0.020	NA	NA
			IC (9.1%)	27.206	1.706	1.049	1.145	1.430	10.223	0.158	0.023
NPCC	NG (42.6%)	NG (100.0%)	CC (87.5%)	0.040	0.009	0.009	0.009	0.004	0.053	0.035	NA
			ST (10.2%)	0.449	0.030	0.037	0.037	0.026	0.230	NA	NA
			GT (2.0%)	1.108	0.084	0.090	0.097	0.116	0.408	NA	NA
	Biomass (4.4%)	MSW (56.4%)	ST (100.0%)	1.254	0.135	0.013	0.013	0.017	0.159	NA	NA
		WDS (43.6%)	ST (98.6%)	0.553	0.016	0.067	0.072	0.048	1.763	0.108	0.056
	Coal (1.1%)	BIT (90.9%)	ST (100.0%)	0.620	1.040	0.015	0.017	0.012	0.198	NA	NA
	Oil (0.6%)	DFO (33.3%)	GT (13.3%)	4.588	0.256	0.096	0.141	0.011	0.463	0.072	0.014
			IC (3.1%)	7.241	0.502	0.651	0.651	1.011	1.620	NA	NA
		KER (7.0%)	GT (97.4%)	18.755	2.826	2.076	2.218	1.199	18.411	NA	NA
		JF (0.2%)	GT (100.0%)	4.912	0.309	0.088	0.088	0.003	0.025	0.051	0.010
RFC	Coal (38.1%)	BIT (57.8%)	ST (99.7%)	0.673	0.766	0.063	0.072	0.010	0.151	NA	NA
		RC (28.3%)	ST (100.0%)	0.457	0.951	0.077	0.101	0.012	0.098	NA	NA
		SUB (12.0%)	ST (100.0%)	0.567	0.898	0.039	0.048	0.016	0.141	NA	NA
		WC (1.3%)	ST (100.0%)	0.674	2.624	0.046	0.051	0.005	0.378	NA	NA
		PC (0.6%)	ST (100.0%)	0.439	2.019	0.165	0.224	0.001	0.053	NA	NA
	NG (25.9%)	NG (100.0%)	CC (87.1%)	0.036	0.002	0.015	0.015	0.003	0.013	0.008	0.001
			GT (7.3%)	0.256	0.004	0.038	0.038	0.010	0.159	0.037	0.011

TABLE 5 (Cont.)

NERC region	Fuel type (share)[b]	Fuel subtype (share)[c]	Combustion technology (share)[d]	NO_x	SO_x	$PM_{2.5}$	PM_{10}	VOC	CO	CH_4	N_2O
			ST (5.3%)	0.539	0.039	0.043	0.043	0.008	0.192	NA	NA
			IC (0.2%)	0.317	0.017	0.093	0.093	0.079	0.216	0.008	0.002
	Biomass (0.7%)	MSW (69.0%)	ST (100.0%)	1.205	0.110	0.062	0.068	0.005	0.188	NA	NA
		WDS (31.0%)	ST (100.0%)	1.164	0.376	0.028	0.032	0.007	0.962	0.182	0.112
	Oil (0.1%)	DFO (93.1%)	GT (20.2%)	1.881	0.430	0.072	0.103	0.003	0.204	0.046	0.010
			IC (2.1%)	57.626	0.501	2.029	2.045	2.818	23.962	0.171	9.201
SERC	NG (35.3%)	NG (100.0%)	CC (88.0%)	0.043	0.002	0.018	0.018	0.006	0.017	NA	NA
			ST (6.6%)	0.772	0.004	0.034	0.035	0.028	0.340	NA	NA
			GT (5.4%)	0.256	0.003	0.048	0.049	0.017	0.161	0.032	0.011
	Coal (31.2%)	BIT (39.8%)	ST (100.0%)	0.702	0.504	0.047	0.052	0.010	0.105	NA	NA
		SUB (30.5%)	ST (100.0%)	0.697	1.333	0.032	0.052	0.018	0.201	NA	NA
		RC (29.4%)	ST (100.0%)	0.646	0.977	0.052	0.066	0.019	0.263	NA	NA
	Biomass (2.0%)	WDS (83.6%)	ST (100.0%)	0.642	0.024	0.042	0.043	0.005	0.562	NA	NA
		MSW (10.3%)	ST (100.0%)	1.388	0.011	0.031	0.034	0.005	0.187	NA	NA
		AB (3.4%)	ST (100.0%)	2.013	0.643	0.155	0.155	0.006	1.499	NA	NA
	Oil (0.1%)	DFO (90.4%)	GT (28.0%)	10.364	4.064	0.112	0.112	0.068	0.222	NA	NA
			IC (4.3%)	94.830	19.140	19.268	27.854	2.665	39.620	NA	0.005
SPP	Coal (41.1%)	SUB (88.4%)	ST (100.0%)	0.626	1.111	0.062	0.073	0.012	0.651	NA	NA
		LIG (7.0%)	ST (100.0%)	0.836	2.011	0.014	0.077	0.013	0.650	NA	NA
	NG (27.2%)	NG (100.0%)	CC (79.8%)	0.069	0.002	0.013	0.015	0.005	0.040	NA	NA
			ST (14.0%)	0.911	0.003	0.037	0.037	0.030	0.997	NA	NA
			GT (5.0%)	0.334	0.003	0.043	0.043	0.023	0.151	NA	NA
			IC (1.2%)	0.170	0.003	0.059	0.059	0.149	0.316	NA	NA
	Oil (0.1%)	DFO (97.1%)	IC (16.7%)	44.450	4.496	8.544	8.545	37.137	11.710	NA	NA
TRE	NG (43.7%)	NG (100.0%)	CC (91.7%)	0.080	0.002	0.015	0.015	0.004	0.057	NA	NA
			ST (5.6%)	0.339	0.003	0.041	0.041	0.030	0.176	NA	NA
			GT (2.2%)	0.290	0.006	0.073	0.073	0.028	0.134	NA	NA

TABLE 5 (Cont.)

NERC region	Fuel type (share)[b]	Fuel subtype (share)[c]	Combustion technology (share)[d]	NO_x	SO_x	$PM_{2.5}$	PM_{10}	VOC	CO	CH_4	N_2O
			IC (0.5%)	0.279	0.005	0.078	0.078	0.124	0.394	NA	NA
	Coal (29.5%)	SUB (68.2%)	ST (100.0%)	0.777	2.404	0.061	0.120	0.012	1.144	NA	NA
		LIG (31.7%)	ST (100.0%)	0.416	1.339	0.098	0.111	0.005	1.212	NA	NA
	Biomass (0.1%)	WDS (100.0%)	ST (100.0%)	0.521	0.006	0.008	0.009	0.002	0.208	NA	NA
	Oil (0.0%)	DFO (100.0%)	IC (0.8%)	31.496	4.557	1.428	1.618	1.407	18.266	NA	NA
WECC	NG (27.8%)	NG (100.0%)	CC (88.8%)	0.055	0.035	0.018	0.019	0.005	0.044	NA	NA
			GT (6.0%)	0.158	0.005	0.031	0.031	0.012	0.113	0.057	NA
			ST (4.3%)	0.425	0.010	0.028	0.028	0.020	0.271	NA	NA
			IC (0.7%)	0.164	0.012	0.062	0.062	0.098	0.119	NA	NA
	Coal (22.8%)	SUB (61.9%)	ST (100.0%)	0.913	0.630	0.041	0.061	0.015	0.268	NA	NA
		BIT (32.2%)	ST (100.0%)	1.081	0.379	0.118	0.162	0.014	0.284	0.158	0.023
		RC (5.5%)	ST (100.0%)	1.005	0.187	0.075	0.095	0.008	0.475	NA	NA
		WC (0.4%)	ST (100.0%)	1.497	1.914	0.028	0.033	0.021	0.067	NA	NA
	Biomass (0.9%)	WDS (80.3%)	ST (100.0%)	0.704	0.063	0.077	0.083	0.033	0.819	NA	NA
		MSW (13.6%)	ST (100.0%)	0.997	0.032	0.049	0.056	0.009	0.063	NA	NA
		AB (6.1%)	ST (100.0%)	0.845	0.088	0.090	0.097	0.004	0.644	NA	NA
	Oil (0.0%)	DFO (95.3%)	IC (13.3%)	14.221	0.373	0.332	0.332	0.434	3.587	NA	NA
		JF (0.7%)	GT (100.0%)	3.766	1.120	0.663	0.669	0.076	0.349	NA	NA

[a] NERC: North American Electric Reliability Council. ASCC: Alaska Systems Coordinating Council. FRCC: Florida Reliability Coordinating Council. HICC: Hawaiian Islands Coordinating Council. MRO: Midwest Reliability Organization. NPCC: Northeast Power Coordinating Council. RFC: Reliability First Corporation. SERC: SERC Reliability Corporation. SPP: Southwest Power Pool. TRE: Texas Regional Entity. WECC: Western Electricity Coordinating Council. NG: natural gas. DFO: distillate fuel oil. BIT: bituminous coal. MSW: municipal solid waste. WDS: wood/wood waste solids. OBS: other biomass solids. RFO: residual fuel oil. AB: agricultural byproduct. SUB: subbituminous coal. RC: refined coal. LIG: lignite coal. KER: kerosene. JF: jet fuel. WC: waste/other coal. PC: petroleum coke. CC: combined cycle. IC: internal combustion engine. GT: gas turbine. ST: steam turbine.

[b] The percentages indicate the shares of fuel in the total electricity generation in the NERC region.

[c] The percentages indicate the share of the fuel subtype in the total electricity generated from the corresponding fuel type.

[d] The percentages indicate the share of the combustion technology in the total electricity generated from the fuel subtype.

[e] NA: not available.

Table 6 lists the national average emission factors by fuel type and combustion technology in comparison with the emission factors in GREET 2019. For each fuel type in Table 6, the emission factors were calculated as the average of the emission factors in Table 4 weighted by the net electricity generation from each subtype of that fuel type. The difference in the estimated emission factors in the two studies is mainly attributable to the different methodologies and datasets used. Estimated emission factors of burning coal and natural gas using steam turbines is comparable to those in GREET 2019. For NGCC power plants, emission factors are comparable for most pollutants except particulate matter; the estimated emission factor of particulate matter in this study is more than 10 times higher than the GREET value. The primary source of the difference is that the methodology and dataset this study used to calculate the emission factors are different from the previous studies. The particulate matter emission factors in GREET were obtained from in-stack flue gas measurement of one NGCC plant.[20] This study, however, used particulate emissions reported by NEI for more than 200 NGCC plants. Note that the particulate emissions reported by NEI were not monitoring data. The particulate emissions were calculated on the basis of a number of methods such as engineering judgment, EPA emission factors, and site-specific emission factors. Given the importance of NGCC in the power generation industry, the emission factors of NGCC should be carefully reviewed in future updates.

The emission factors of EGUs burning natural gas with internal combustion engines estimated by this study is 1 order of magnitude lower than those in GREET 2019. Again, the differences are likely due to the change in the methodologies and datasets of the two studies. Taking the NO_x emission factor for example, the NO_x emission factor in GREET was calculated based on facility NO_x emissions reported by eGRID. The NO_x emissions from burning natural gas using internal combustion engines were calculated using an uncontrolled emission factor (2.768 lb./mcf, or 0.044 kg/m^3) because these power plants are usually small and do not report to CAMD.[15] However, such high NO_x emissions would not be allowed for larger plants due to the emission regulations for stationary engines in the United States.[21] Emissions of 0.03 g NO_x, 0.09 g CO, and 0.05 g VOC per kWh of electricity generation have been reported for a 9-MW gas engine with emission control.[17] It is thus expected that the emission factors obtained in this study for burning natural gas in internal combustion engines probably better reflect actual emissions subject to regulations.

Significant differences exist between this study and GREET 2019 for the emission factors burning oil with internal combustion engines. It is not clear which study achieves a better estimate of the emission factors because none of the emission data used in the two studies came from real-world monitored data. The NEI emission data of these facilities were calculated indirectly using a variety of methods, site-specific emission factors, vendor emission factors, stack test, and other information. Nonetheless, these oil-fired power plants usually have very small EGUs (nameplate capacity < 25 MW) and are generally not subject to regulations that require CAMD-based emission reporting.

Table 7 lists the emission factors by fuel type for each NERC region.

TABLE 6 National generation-weighted average emission factors (in g/kWh) by fuel type and comparison with the emission factors in GREET 2019.[a]

Fuel type (share)[b]	Combustion technology (share)[c]	Calculation method	NO_x	SO_x	$PM_{2.5}$	PM_{10}	VOC	CO	CH_4	N_2O
NG (32.8%)	CC (83.1%)	This study	0.050	0.007	0.017	0.017	0.004	0.034	0.009	0.001
		GREET 2019	0.108	0.004	0.001	0.001	0.002	0.090	0.007	0.001
	GT (8.8%)	This study	0.264	0.005	0.041	0.041	0.017	0.151	0.03	0.008
		GREET 2019	0.321	0.016	0.036	0.036	0.011	0.414	0.011	0.001
	ST (7.1%)	This study	0.654	0.010	0.035	0.036	0.025	0.339	NA[d]	NA
		GREET 2019	0.822	0.166	0.041	0.041	0.03	0.458	0.011	0.001
	IC (1.0%)	This study	0.167	0.011	0.054	0.054	0.093	0.183	0.008	0.002
		GREET 2019	2.974	0.006	0.455	0.455	1.071	3.684	0.011	0.001
Coal (30.0%)	ST (100.0%)	This study	0.708	0.942	0.060	0.076	0.013	0.297	0.158	0.023
		GREET 2019	0.362	2.364	0.043	0.061	0.009	0.056	0.01	0.015
Biomass (1.4%)	ST (100.0%)	This study	0.679	0.049	0.069	0.073	0.032	1.182	0.113	0.06
		GREET 2019	0.923	NA	0.610	2.094	0.134	4.733	0.491	0.065
Oil (0.3%)	ST (76.6%)	This study	2.251	2.737	0.131	0.161	0.011	0.082	NA	NA
		GREET 2019	4.226	3.604	0.132	0.169	0.02	0.158	0.031	0.006
	GT (13.5%)	This study	4.657	1.067	0.252	0.290	0.11	1.757	0.048	0.01
		GREET 2019	2.734	0.434	0.070	0.170	0.003	0.017	0.032	0.006
	IC (9.9%)	This study	13.614	0.483	0.832	0.814	0.689	2.114	0.07	0.069
		GREET 2019	4.532	0.109	0.012	0.008	0.011	0.03	0.028	0.006

[a] NG: natural gas. CC: combined cycle. GT: gas turbine. ST: steam turbine. IC: internal combustion engine.
[b] The percentages indicate the shares of fuel in the total electricity generation in the United States.
[c] The percentages indicate the share of the combustion technology in the total electricity generated from the fuel type.
[d] NA: not available.

TABLE 7 Generation-weighted average emission factors (in g/kWh) by fuel type for each NERC region.[a]

NERC region	Fuel type (share)[b]	Combustion technology (share)[c]	NO_x	SO_x	$PM_{2.5}$	PM_{10}	VOC	CO	CH_4	N_2O
ASCC	NG (50.4%)	CC (64.6%)	0.533	0.005	0.004	0.023	0.010	0.123	NA[d]	NA
		IC (24.4%)	0.050	0.015	0.017	0.017	0.041	0.026	NA	NA
		GT (11.0%)	1.488	0.017	0.054	0.058	0.413	0.648	NA	NA
	Oil (13.6%)	IC (72.5%)	13.498	0.326	0.603	0.544	0.587	1.760	0.000	NA
		GT (26.6%)	9.525	3.903	0.134	0.134	0.006	0.048	NA	NA
FRCC	NG (68.6%)	CC (86.2%)	0.048	0.002	0.022	0.022	0.002	0.050	NA	NA
		ST (8.0%)	0.550	0.003	0.036	0.036	0.026	0.019	NA	NA
		GT (5.6%)	0.213	0.003	0.032	0.032	0.009	0.077	NA	NA
	Coal (15.1%)	ST (100.0%)	0.440	1.022	0.109	0.133	0.005	0.308	NA	NA
	Biomass (2.4%)	ST (100.0%)	0.848	0.045	0.094	0.098	0.013	1.080	NA	NA
HICC	Oil (67.7%)	ST (86.0%)	2.251	2.737	0.131	0.161	0.011	0.082	NA	NA
		IC (8.0%)	7.930	0.001	0.208	0.214	0.109	0.141	NA	NA
	Biomass (4.8%)	ST (100.0%)	1.770	0.298	0.013	0.013	0.162	0.561	NA	NA
MRO	Coal (51.0%)	ST (100.0%)	0.847	1.252	0.072	0.086	0.018	0.339	NA	NA
	NG (7.6%)	CC (69.6%)	0.047	0.002	0.006	0.007	0.001	0.118	0.010	0.001
		GT (16.8%)	0.422	0.005	0.026	0.028	0.009	0.195	0.011	0.001
		ST (9.6%)	1.290	0.007	0.055	0.055	0.048	0.392	NA	NA
		IC (4.1%)	0.361	0.003	0.097	0.098	0.140	0.706	0.009	0.001
	Oil (0.1%)	GT (20.4%)	6.320	0.020	0.107	0.107	0.000	0.020	NA	NA
		IC (5.9%)	27.206	1.706	1.049	1.145	1.430	10.223	0.158	0.023

TABLE 7 (Cont.)

NERC region	Fuel type (share)[a]	Combustion technology (share)[b]	NO_x	SO_x	$PM_{2.5}$	PM_{10}	VOC	CO	CH_4	N_2O
NPCC	NG (42.6%)	CC (83.2%)	0.040	0.009	0.009	0.009	0.004	0.053	0.035	NA
		ST (9.6%)	0.449	0.030	0.037	0.037	0.026	0.230	NA	NA
		GT (6.0%)	1.108	0.084	0.090	0.097	0.116	0.408	NA	NA
	Biomass (4.4%)	ST (100.0%)	0.553	0.016	0.067	0.072	0.048	1.763	0.108	0.056
	Coal (1.1%)	ST (100.0%)	0.620	1.040	0.015	0.017	0.012	0.198	NA	NA
	Oil (0.6%)	GT (15.5%)	13.053	1.792	1.278	1.381	0.721	11.176	0.071	0.014
		IC (2.0%)	7.241	0.502	0.651	0.651	1.011	1.620	NA	NA
RFC	Coal (38.1%)	ST (100.0%)	0.597	0.866	0.064	0.078	0.011	0.138	NA	NA
	NG (25.9%)	CC (81.0%)	0.036	0.002	0.015	0.015	0.003	0.013	0.008	0.001
		GT (9.4%)	0.256	0.004	0.038	0.038	0.010	0.159	0.037	0.011
		ST (8.2%)	0.539	0.039	0.043	0.043	0.008	0.192	NA	NA
		IC (1.4%)	0.317	0.017	0.093	0.093	0.079	0.216	0.008	0.002
	Biomass (0.7%)	ST (100.0%)	1.164	0.376	0.028	0.032	0.007	0.962	0.182	0.112
	Oil (0.1%)	GT (19.8%)	1.881	0.430	0.072	0.103	0.003	0.204	0.046	0.010
		IC (2.2%)	57.626	0.501	2.029	2.045	2.818	23.962	0.171	9.201
SERC	NG (35.3%)	CC (82.9%)	0.043	0.002	0.018	0.018	0.006	0.017	NA	NA
		GT (9.4%)	0.256	0.003	0.048	0.049	0.017	0.161	0.032	0.011
		ST (7.1%)	0.772	0.004	0.034	0.035	0.028	0.340	NA	NA
	Coal (31.2%)	ST (100.0%)	0.684	0.897	0.044	0.056	0.015	0.181	NA	NA
	Biomass (2.0%)	ST (100.0%)	0.695	0.048	0.046	0.047	0.005	0.598	NA	NA
	Oil (0.1%)	GT (22.9%)	10.364	4.064	0.112	0.112	0.068	0.222	NA	NA
		IC (3.7%)	94.830	19.140	19.268	27.854	2.665	39.620	NA	0.005

TABLE 7 (Cont.)

NERC region	Fuel type (share)[a]	Combustion technology (share)[b]	NO_x	SO_x	$PM_{2.5}$	PM_{10}	VOC	CO	CH_4	N_2O
SPP	Coal (41.1%)	ST (100.0%)	0.641	1.177	0.058	0.074	0.012	0.651	NA	NA
	NG (27.2%)	CC (76.4%)	0.069	0.002	0.013	0.015	0.005	0.040	NA	NA
		ST (14.3%)	0.911	0.003	0.037	0.037	0.030	0.997	NA	NA
		GT (8.0%)	0.334	0.003	0.043	0.043	0.023	0.151	NA	NA
		IC (1.3%)	0.170	0.003	0.059	0.059	0.149	0.316	NA	NA
	Oil (0.1%)	IC (16.0%)	44.450	4.496	8.544	8.545	37.137	11.710	NA	NA
TRE	NG (43.7%)	CC (86.7%)	0.080	0.002	0.015	0.015	0.004	0.057	NA	NA
		GT (8.7%)	0.290	0.006	0.073	0.073	0.028	0.134	NA	NA
		ST (4.1%)	0.339	0.003	0.041	0.041	0.030	0.176	NA	NA
		IC (0.6%)	0.279	0.005	0.078	0.078	0.124	0.394	NA	NA
	Coal (29.5%)	ST (100.0%)	0.662	2.066	0.073	0.117	0.010	1.166	NA	NA
	Biomass (0.1%)	ST (100.0%)	0.521	0.006	0.008	0.009	0.002	0.208	NA	NA
	Oil (0.0%)	IC (0.9%)	31.496	4.557	1.428	1.618	1.407	18.266	NA	NA
WECC	NG (27.8%)	CC (83.7%)	0.055	0.035	0.018	0.019	0.005	0.044	NA	NA
		GT (10.7%)	0.158	0.005	0.031	0.031	0.012	0.113	0.057	NA
		ST (4.0%)	0.425	0.010	0.028	0.028	0.020	0.271	NA	NA
		IC (1.6%)	0.164	0.012	0.062	0.062	0.098	0.119	NA	NA
	Coal (22.8%)	ST (100.0%)	0.974	0.530	0.068	0.095	0.014	0.284	0.158	0.023
	Biomass (0.9%)	ST (100.0%)	0.714	0.065	0.078	0.084	0.031	0.807	NA	NA
	Oil (0.0%)	IC (12.4%)	14.221	0.373	0.332	0.332	0.434	3.587	NA	NA
		GT (5.8%)	3.766	1.120	0.663	0.669	0.076	0.349	NA	NA

[a] NERC: North American Electric Reliability Council. ASCC: Alaska Systems Coordinating Council. FRCC: Florida Reliability Coordinating Council. HICC: Hawaiian Islands Coordinating Council. MRO: Midwest Reliability Organization. NPCC: Northeast Power Coordinating Council. RFC: Reliability First Corporation. SERC: SERC Reliability Corporation. SPP: Southwest Power Pool. TRE: Texas Regional Entity. WECC: Western Electricity Coordinating Council. NG: natural gas. CC: combined cycle. IC: internal combustion engine. GT: gas turbine. ST: steam turbine.

[b] The percentages indicate the shares of fuel in the total electricity generation in the NERC region.

[c] The percentages indicate the share of the combustion technology in the total electricity generated from the fuel type.

[d] NA: not available.

3.3.1 Validation of CO_2 Emission Factors

The emission factor of CO_2 can be calculated using the same method as the emission factors of other pollutants. However, GREET by default used another methodology that calculates CO_2 emission factors directly based on carbon balance using the carbon content and LHV of fuel and power generation efficiency. Table 8 lists the LHVs and carbon content of the fuels in GREET. The CO_2 emission factors calculated using the two methods are compared in Table 9.

TABLE 8 Fuel properties data from GREET 2019.

Fuel type	LHV	Unit of LHV	Carbon ratio by weight
Coal	19,474,169	Btu/short ton	58.6%
natural gas	983	Btu/ft^3	72.4%
Biomass[a]	17,289,000	Btu/short ton	50.3%
Oil	140,353	Btu/gal	86.8%

[a] Data of forest residues in GREET 2019 are used.[3]

TABLE 9 Comparison of CO_2 calculated by GREET and from emission data.

Fuel	Combustion technology	CO_2 emission factor calculated by GREET (g/kWh)	CO_2 emission factor calculated from emission data (g/kWh)	Difference
Coal	Steam turbine	987	1,012	2.5%
Natural gas	Combined cycle	393	392	-0.3%
	Gas turbine	616	598	-3.0%
	Internal combustion engine	494	444	-10.1%
	Steam turbine	598	617	3.1%
Biomass[a]	Steam turbine	1,523	1,456	-4.6%
Oil	Gas turbine	1,076	913[b]	-15.1%
	Internal combustion engine	826	644[b]	-22.0%

[a] Data of forest residues are used.[3]

[b] Emission factors greater than 10,000 g/kWh are removed before calculating the CO_2 emission factor because the high CO_2 emission factors indicate that plant efficiencies are very low (~2%), which is unlikely to be true for a power plant.

Good agreement of CO_2 emission factors calculated from both methods was observed for coal boilers and NGCC, which are the most prevalent fuel and combustion technologies for electricity generation in the United States, together accounting for 59% of total electricity generation in the nation. The CO_2 emission factors of burning natural gas with internal combustion engines are different by 10%. A 5% difference is also observed for plants burning biomass with a steam turbine. Since both the GREET-calculated results and the emission-derived results are based on the same underlying efficiency, the differences in the results obtained by these methods are mainly driven by the difference in biomass feedstock properties such as carbon contents and heating values.

Large differences exist in oil-fired power plants. Besides the differences in fuel properties, the different emission control systems these plants use may also contribute to the differences in CO_2 emission factors estimated by GREET and that calculated from emission data. Another possible reason for the relatively large discrepancies of the oil-fired power plants is that unlike coal-fired and NGCC power plants whose emission data are from CEMS, emissions of oil-fired power plants are estimated based on a variety of emission factors (site-specific emission factors, vendor emission factors, trade group emission factors, etc.[22]) and are subject to uncertainty. GREET calculates CO_2 emission factors based on technology efficiency and carbon balance, including carbon in CO and VOC emissions. Therefore, uncertainty in CO and VOC emissions reported in the NEI dataset may affect the accuracy of the CO_2 emissions calculated with the carbon balance approach in GREET.

It should be noted that the combinations of fuel and combustion which see large differences between the CO_2 emission factors calculated from the two methods only accounted for a small portion of net power generation. Power plants burning natural gas with internal combustion engines and those burning biomass with steam turbines account for 0.09% and 0.7% of the nation's total power generation, respectively. Oil-fired power plants accounted for 0.3% of the total power generation.

3.3.2 Life-cycle GHG Emission Intensities of Electricity Generation by Coal Boiler and NGCC

Using the updated energy efficiencies and emission factors, we calculated the life-cycle GHG emission intensities of the two most prevalent electricity generation pathways: power generation from NGCC and burning coal using steam turbine. These two technologies together contributed to 59% of the electricity generated in the United States in 2017. The results are compared to those of GREET 2019, as shown in Table 10. The results shown here include the emissions from each stage of electricity generation, including feedstock production (coal mining, natural gas extraction, etc.), feedstock transportation, and combustion. These results are different from the emissions factors shown in Tables 4–7, which only include the emissions from direct combustion of the fuels. The update suggests an increase of about 5–7% in the carbon intensities of both technologies. The increases in the carbon intensities can be explained by (a) a decrease in electricity generation efficiencies for both technologies (the electricity generation efficiencies were projections of historical trends[16]), and (b) an increase in CO_2 emission factors.

TABLE 10 Comparison of pathway GHG emissions in GREET 2019 and current study.

Fuel	Combustion technology	GHG emissions in GREET 2019 (g/kWh)	GHG emissions in current study (g/kWh)	Difference
Natural gas	CC	462	492	6.5%
Coal	ST	1062	1,113	4.8%

3.3.3 State-level Electricity Generation Life-cycle GHG and CAP Emission Intensities

Figure 1 shows the generation-weighted average life-cycle GHG emission intensities of power generation by state. The average GHG emission intensity of power generation in West Virginia is the highest (1,021 g CO_2 eq./kWh) in the nation. Vermont produces the cleanest electricity with respect to GHG emissions (19 g CO_2 eq./kWh). The GHG emission intensity of electricity is mainly driven by the share of local electricity generation mix representing relative shares of power sources for power generation. Coal-fired electricity accounts for 93%, 86%, and 79% of the total power generation in West Virginia, Wyoming, and Kentucky, respectively. Therefore, GHG emission intensities of the electricity generated in these states are high (>950 g CO_2 eq./kWh). Vermont, Idaho, and Washington rely heavily on nuclear and other renewable electricity. Renewable electricity accounts for around 80% of total electricity generation in these states. As a result, the carbon intensities of the electricity generated in these states are low.

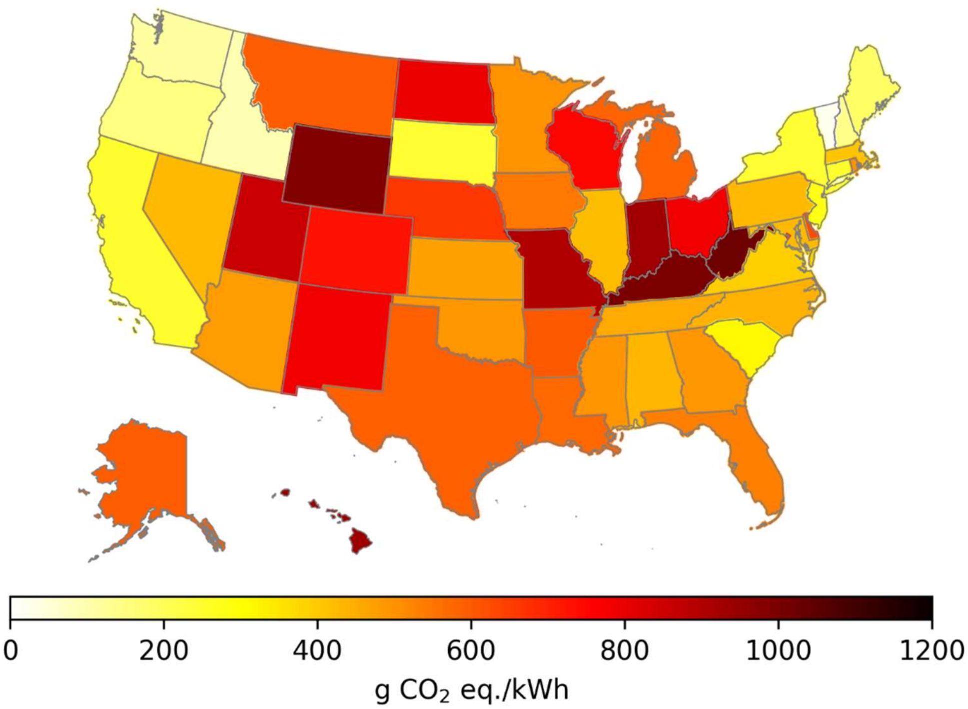

FIGURE 1 State-level GHG emission intensities of electricity generation

Figures 2–7 present life-cycle CAP emissions of electricity generation for each state. Hawaii and Alaska rely heavily on oil for power generation; 68% and 14% of electricity is generated from burning oil in Hawaii and Alaska, respectively, while less than 1% of electricity was generated from oil in the other states. CAP emission factors from oil combustion are high. As a result, the life-cycle emissions of all CAP emissions are high for Alaska and Hawaii. Life-cycle CAP emissions are also high in states such as West Virginia, Wyoming, Missouri, Kentucky, Utah, and Indiana, where electricity is mostly generated from burning coal. The states that generate most electricity from natural gas, including Delaware, Mississippi, Nevada, Massachusetts, Florida, and Louisiana, have lower CAP emissions than the abovementioned states that rely more on coal. In contrast, the states that generate electricity from nuclear and other renewable sources, including Washington, Idaho, Vermont, and California, have the lowest CAP emissions.

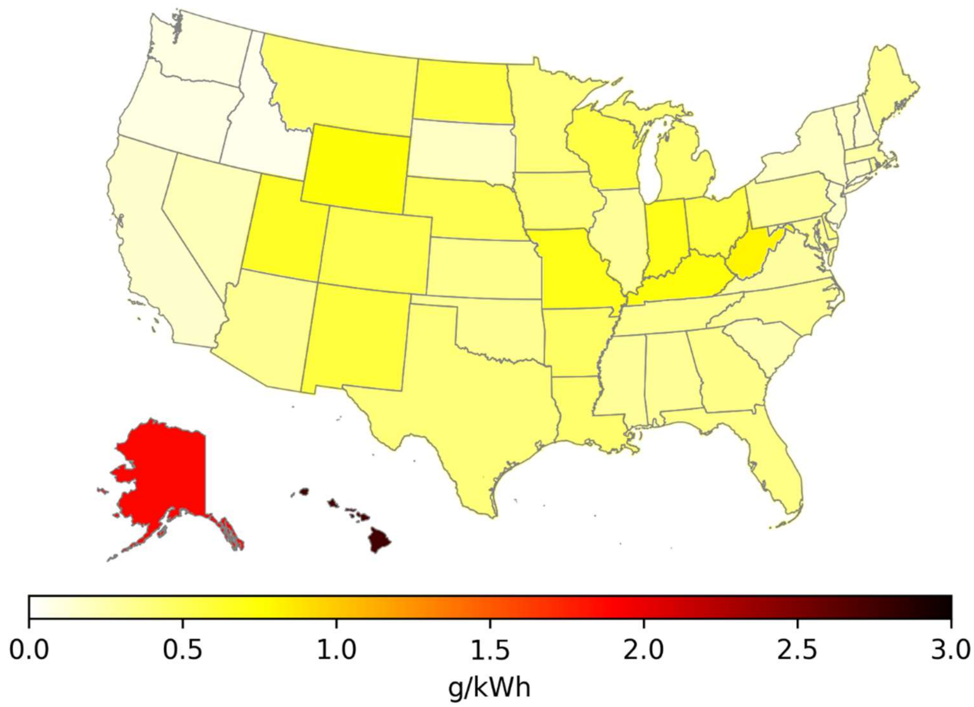

FIGURE 2 State-level life-cycle NO_x emissions of electricity generation

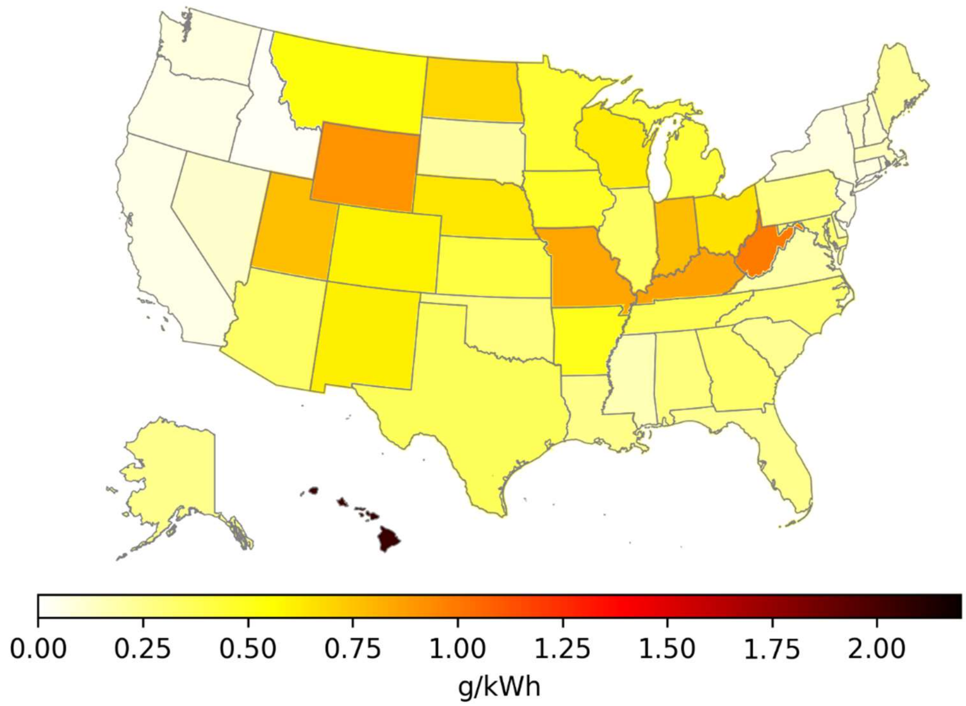

FIGURE 3 State-level life-cycle SO_x emissions of electricity generation

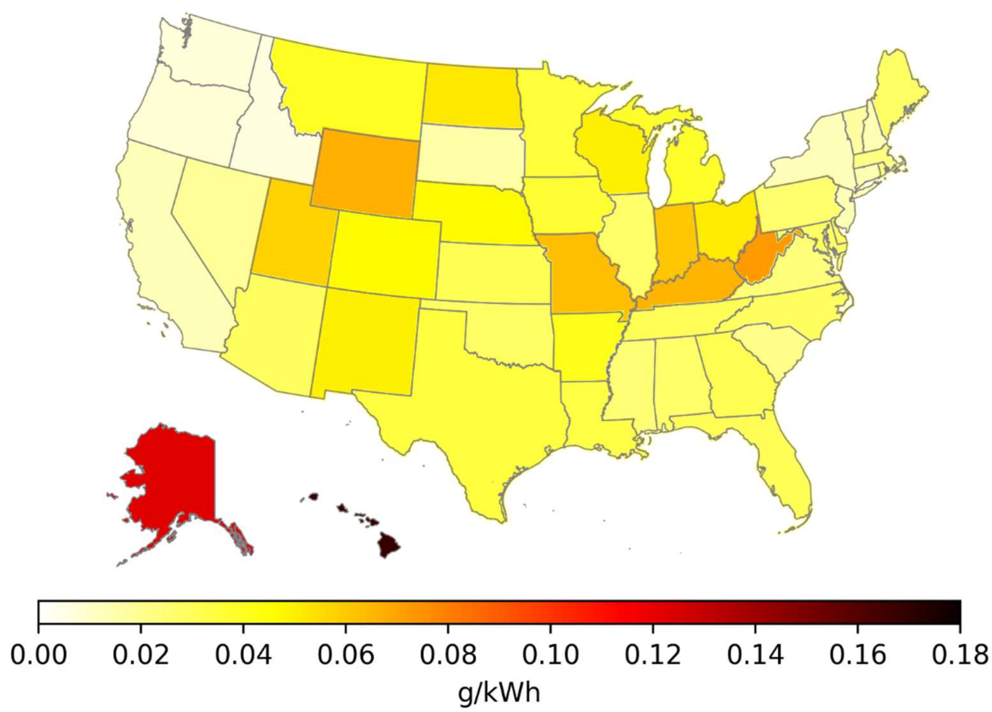

FIGURE 4 State-level life-cycle $PM_{2.5}$ emissions of electricity generation

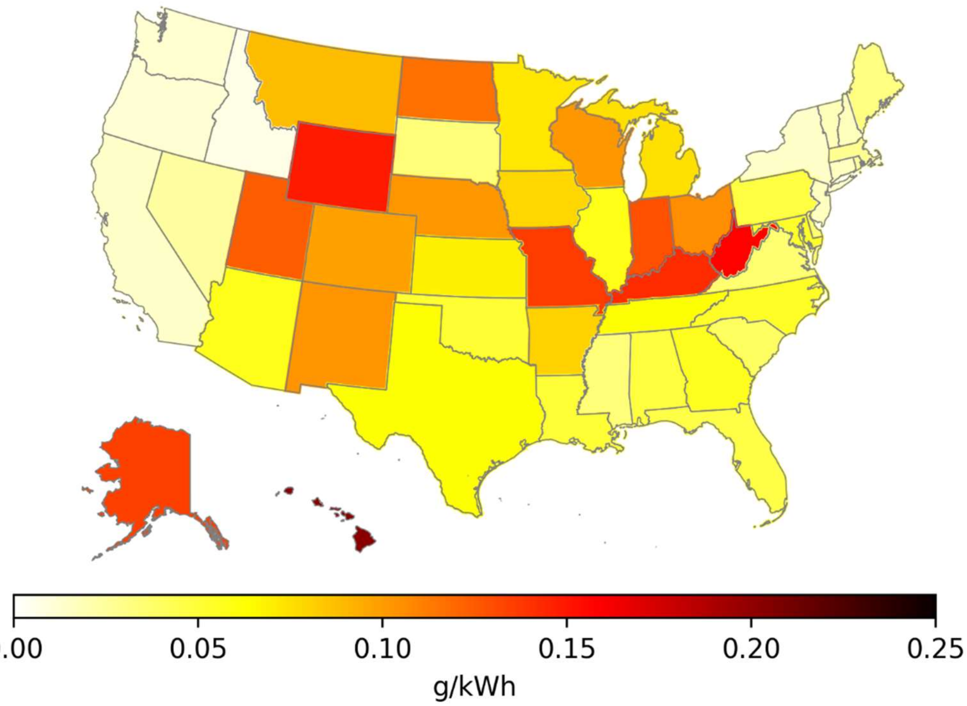

FIGURE 5 State-level life-cycle PM_{10} emissions of electricity generation

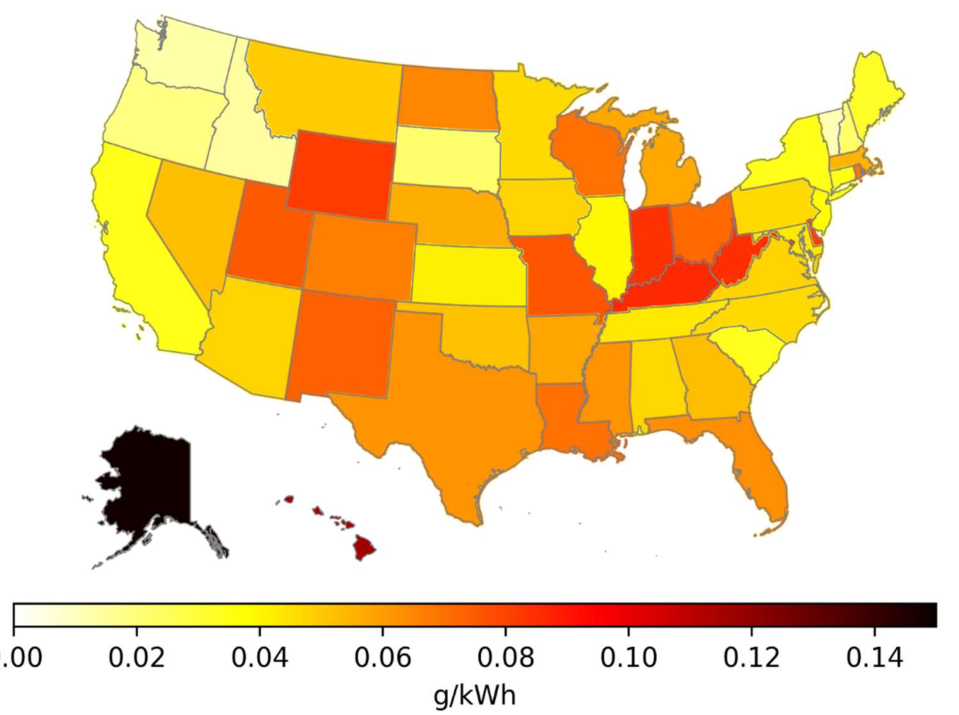

FIGURE 6 State-level life-cycle VOC emissions of electricity generation

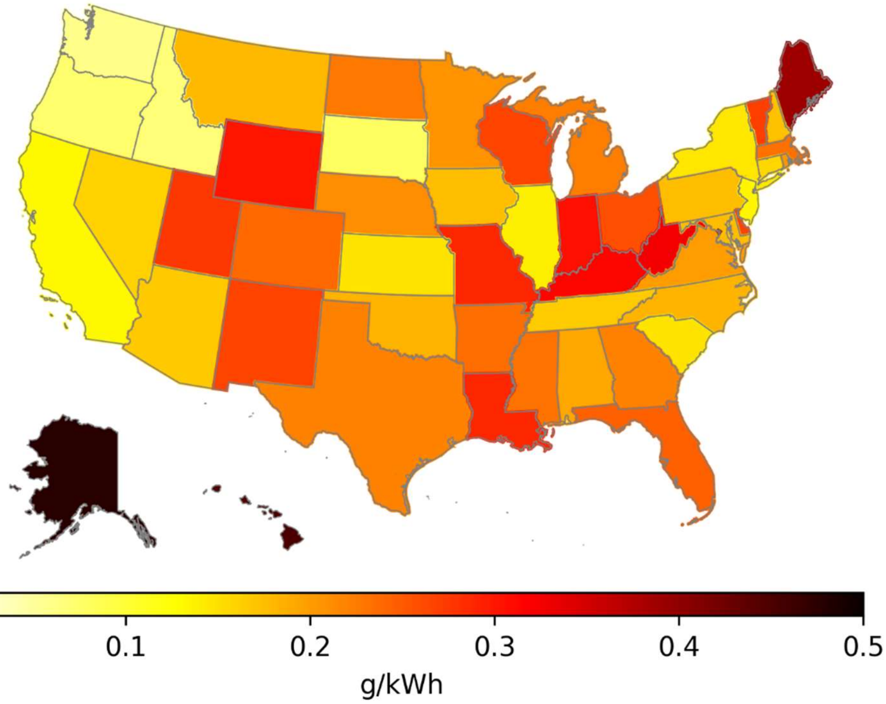

FIGURE 7 State-level life-cycle CO emissions of electricity generation

3.4 PROBABILITY DISTRIBUTION FUNCTIONS OF ELECTRICITY GENERATION EFFICIENCIES AND EMISSION FACTORS

Table 11 summarizes the PDFs of the electricity generation efficiencies and emission factors by fuel type and combustion technology. The best-fit PDFs were selected based on the 11 default PDFs in GREET's add-on Stochastic Simulation Tool. The best-fit PDFs of energy efficiencies and emission factors were implemented in GREET to allow the users to perform uncertainty analysis of life-cycle GHG and CAP emissions of various vehicle and fuel systems.

TABLE 11 Probability density functions of U.S. average electricity generation efficiencies, and pollutant emission factors by fuel type and combustion technology.[a]

Fuel type	Combustion technology	Efficiency, GHG, CAP	PDF type	PDF parameters
Coal	ST	Efficiency	Logistic	σ = 0.01154, μ = 0.34685
		NO_x	Gamma	L = 0.17417, α = 0.26038, β = 1.9676
		SO_x	Gamma	L = 0, α = 0.28324, β = 2.0991
		$PM_{2.5}$	Weibull	L = 0, α = 0.05726, β = 1.0577
		PM_{10}	Weibull	L = -1.4672E-4, α = 0.07896, β = 1.1844

TABLE 11 (Cont.)

Fuel type	Combustion technology	Efficiency, GHG, CAP	PDF type	PDF parameters
		VOC	Extreme value (min)	α = 0.01571, β = 0.0049
		CO	Logistic	σ = 0.02803, μ = 0.1179
Biomass	ST	Efficiency	Gamma	L = 0.04869, α = 0.01079, β = 16.321
		NO_x	Weibull	L = -0.07534, α = 1.2960, β = 2.2578
		SO_x	Triangular	a = 2.3039E-6, b = 0.17512, m = 1.5796E-5
		$PM_{2.5}$	Gamma	L = 4.8330E-11, α = 0.07658, β = 0.5602
		PM_{10}	Gamma	L = 0, α = 0.04466, β = 0.9374
		VOC	Triangular	a = 4.5767E-6, b = 0.02067, m = 4.6628E-6
		CO	Gamma	L = 0, α = 0.02567, β = 3.3543
NG	CC	Efficiency	Weibull	L = 0, α = 0.53197, β = 22.682
		NO_x	Extreme value (max)	α = 0.02676, β = 0.00901
		SO_x	Gamma	L = 9.6549E-4, α = 1.1106E-5, β = 90.071
		$PM_{2.5}$	Weibull	L = -8.8965E-4, α = 0.01905, β = 1.9057
		PM_{10}	Weibull	L = -7.3144E-4, α = 0.01944, β = 2.0147
		VOC	Gamma	L = 0, α = 0.00319, β = 1.2371
		CO	Exponential	λ = 67.477
	IC	Efficiency	Logistic	σ = 0.02186, μ = 0.4154
		NO_x	Uniform	a = 0.03155, b = 0.08087
		SO_x	Logistic	σ = 1.0300E-4, μ = 0.00251
		$PM_{2.5}$	Gamma	L = 0.00103, α = 0.05922, β = 0.86473
		PM_{10}	Gamma	L = 0.00103, α = 0.05652, β = 0.86202
		VOC	Weibull	L = 0, α = 0.07235, β = 1.1617
		CO	Exponential	λ = 15.490
	GT	Efficiency	Weibull	L = 0, α = 0.35268, β = 9.6078
		NO_x	Extreme value (max)	α = 0.1394, β = 0.099
		SO_x	Extreme value (max)	α = 0.00287, β = 3.4956E-4
		$PM_{2.5}$	Gamma	L = -0.02209, α = 0.00741, β = 7.7637
		PM_{10}	Gamma	L = -0.02198, α = 0.00712, β = 8.106
		VOC	Logistic	σ = 0.00443, μ = 0.01081
		CO	Weibull	L = 0, α = 0.10593, β = 0.10593
	ST	Efficiency	Weibull	L = 0, α = 0.34229, β = 14.378
		NO_x	Gamma	L = -0.31401, α = 0.1783, β = 5.413
		SO_x	Gamma	L = 0.00234, α = 1.3874E-4, β = 5.9916
		$PM_{2.5}$	Gamma	L = -0.05148, α = 6.8447E-4, β = 130.4
		PM_{10}	Gamma	L = -0.05514, α = 6.6544E-4, β = 139.47
		VOC	Triangular	a = 1.1227E-9, b = 0.05383, m = 0.0262
		CO	Uniform	a = -0.08334, b = 0.60239
Oil	IC	Efficiency	Logistic	σ = 0.02158, μ = 0.36658
		NO_x	Extreme value (min)	α = 13.946, β = 3.3546
		SO_x	Extreme value (max)	α = 0.00235, β = 0.00181
		$PM_{2.5}$	Logistic	σ = 0.04365, μ = 0.21314

TABLE 11 (Cont.)

Fuel type	Combustion technology	Efficiency, GHG, CAP	PDF type	PDF parameters
		PM_{10}	Uniform	a = 0.0853, b = 0.50635
		VOC	Uniform	a = 0.02805, b = 0.59599
		CO	Weibull	L = 0.04128, α = 1.2333, β = 0.87975
	GT	Efficiency	Weibull	L = -6.9792E6, α = 6.9792E6, β = 1.4136E8
		NO_x	Exponential	λ = 0.30831
		SO_x	Normal	σ = 0.12556, μ = 0.17632
		$PM_{2.5}$	Uniform	a = 0.02269, b = 0.128
		PM_{10}	Uniform	a = 0.02236, b = 0.12357
		VOC	Uniform	a = -1.9640E-4, b = 0.00461
		CO	Weibull	L = 0.01543, α = 0.01367, β = 1.3712

[a] PDFs of energy efficiency and emission factors are not generated for power plants burning oil with steam turbines because data are only available for a very small number (2) of plants. PDFs of N_2O and CH_4 emission factors are not generated for any fuel type or combustion technology because emission factors are not available for most of the plants.

3.5 ELECTRICITY TRANSMISSION AND DISTRIBUTION LOSS FACTORS

National- and state-average electricity T&D loss factors calculated from Equation (3) are shown in Table 12.

TABLE 12 Electricity T&D loss factors on state and national average basis.

Region	T&D loss	Region	T&D loss
Alabama	5.12%	Montana	4.71%
Alaska	4.88%	Nebraska	4.87%
Arizona	4.88%	Nevada	4.88%
Arkansas	4.88%	New Hampshire	4.88%
California	4.78%	New Jersey	4.88%
Colorado	4.88%	New Mexico	4.88%
Connecticut	4.88%	New York	4.88%
Delaware	4.88%	North Carolina	4.88%
District of Columbia	4.88%	North Dakota	4.85%
Florida	4.88%	Ohio	4.88%
Georgia	4.88%	Oklahoma	4.88%
Hawaii	5.14%	Oregon	4.87%
Idaho	4.88%	Pennsylvania	4.88%
Illinois	4.88%	Rhode Island	4.88%
Indiana	4.88%	South Carolina	4.88%
Iowa	4.88%	South Dakota	4.88%
Kansas	4.88%	Tennessee	4.88%
Kentucky	4.88%	Texas	4.87%
Louisiana	4.88%	Utah	4.88%
Maine	4.84%	Vermont	4.87%
Maryland	4.88%	Virginia	4.88%
Massachusetts	4.88%	Washington	4.62%
Michigan	4.88%	West Virginia	4.88%
Minnesota	4.86%	Wisconsin	4.88%
Mississippi	4.88%	Wyoming	4.88%
Missouri	4.88%	United States	4.86%

4 OUTSTANDING ISSUES

The “top-down” approach developed here to estimate fuel- and combustion technology-specific emissions and efficiency characteristics of electricity generation works well for the U.S. national average case when a decent coverage of emission data can be achieved for all the major fuel types and major combustion technologies for electricity generation. However, we face a data limitation issue at the state-level when a small number of power plants, and in some cases, no power plants that utilize a dominant fuel and a specific combustion technology could be found after the pairing process.

State-level, detailed fuel- and combustion technology-specific results, which vary with fuel properties, as well as the engineering design, configuration, and emission control options of power plants, provide necessary granularity to model the energy and emissions impacts of choices of fuel and combustion technologies to generate electricity by manufacturers of all kinds. With the data limitation issue at the state-level in mind, it may be reasonable to expect that the same choice for fuel and combustion technology options at the state level would present similar performances on thermal efficiency and emissions, assuming similar levels of emission control practices for the same technology choices at the state level and the national level. Therefore, we applied the national average efficiencies and emission factors, together with the state-level fuel- and combustion technology mixes estimated in this work to estimate state-level life-cycle emission intensities as shown in Figures 1-7.

In a future GREET release, aggregated state-level emission intensities can be estimated by dividing the total state level power generation emissions by the total state-level net electricity generation. Such aggregated, generation-based results may be useful to address energy and emission impacts of consuming such electricity by consumers that would not be able to choose specific fuel and combustion technology options to generate electricity on their own. In addition, emission results of generation-based electricity can serve as a basis for estimating consumption-based results when electricity exchanges among states are considered. Granular details of electricity generation at the fuel and combustion level could provide opportunities to improve accuracy and representation of consumption-based results.

5 CONCLUSION

This study estimated electricity generation mixes, efficiencies, and pollutant emission factors using the latest EIA-923 and NEI datasets. The emission factors of pollutants (NO_x, SO_x, $PM_{2.5}$, PM_{10}, CH_4, N_2O, VOC, and CO) were calculated using a new top-down approach, where emission factors were estimated based on plant-level emissions from the facilities burning a dominant fuel using a dominant combustion technology.

The power generation industry in the United States has seen a shift from coal toward natural gas over the last decade. The share of electricity generation from natural gas increased from 24% in 2010 to 33% in 2017, while the share of electricity generation from coal decreased from 49% to 30%.[4] This update also captures the increase in electricity generation efficiencies due to the retirement of less-efficient old generators and the installation of new, more efficient generators,[2] as well as the impacts of efficiency gain on the pollutant emission factors.

The new approach adopted in this study allows the emission factors of all the pollutants to be calculated from one data source (the 2017 NEI datasets[7]). However, it requires us to link the electricity generation data (EIA-923) to the emission data (NEI), which is not a trivial process. The linkage between the electricity generation and the emission data was completed for a sizeable fraction (>80% by the total net electricity generation) of power plants for most electricity-generation fuels and technologies. Nonetheless, there are still a small number of power plants (especially those fired by oil) whose electricity generation and emission data have not been linked. Future research efforts are required to link the electricity generation and emission data for these plants to achieve better estimates of the emission factors.

It should also be noted that the NEI dataset used in this study lacks N_2O and CH_4 emissions from EGUs for many power plants, as shown in Tables 4 and 5. N_2O and CH_4 emission data may be obtained from other sources such as Greenhouse Gas Reporting Program in future studies to improve the estimate of N_2O and CH_4 emission factors.

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